UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q

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

For the Quarterly Period Ended 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 ☒ No ☐

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

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

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

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

The number of shares outstanding of each registrant's common stock as of 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

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

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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

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.

PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

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

(In millions, except per share data)	Three Months Ended March 31, 2013	Three Months Ended March 31, 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

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

(In millions)	Three Months Ended March 31, 2013	Three Months Ended March 31, 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

See the Combined Notes to Consolidated Financial Statements

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

See the Combined Notes to Consolidated Financial Statements

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

See the Combined Notes to Consolidated Financial Statements

EXELON CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDERS' EQUITY
(Unaudited)

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

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	Three Months Ended 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

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	Three Months Ended March 31, 2013	Three Months Ended March 31, 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

See the Combined Notes to Consolidated Financial Statements

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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

See the Combined Notes to Consolidated Financial Statements

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	Three Months Ended March 31, 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

See the Combined Notes to Consolidated Financial Statements

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

See the Combined Notes to Consolidated Financial Statements

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

See the Combined Notes to Consolidated Financial Statements

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

See the Combined Notes to Consolidated Financial Statements

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

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	Three Months Ended March 31, 2013	Three Months Ended March 31, 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

See the Combined Notes to Consolidated Financial Statements

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

See the Combined Notes to Consolidated Financial Statements

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)

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	Three Months Ended March 31, 2013	Three Months Ended March 31, 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

See the Combined Notes to Consolidated Financial Statements

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

See the Combined Notes to Consolidated Financial Statements

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

See the Combined Notes to Consolidated Financial Statements

BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDERS' EQUITY
(Unaudited)

(In millions)	Common Stock	Retained Earnings	Total Shareholders' Equity	Preference stock not subject to mandatory redemption	Total Equity
Balance, December 31, 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

See the Combined Notes to Consolidated Financial Statements

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.

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.

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.

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.

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.

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 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.

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

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.

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.

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

(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 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 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.

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.

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 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 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.

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 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 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 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.

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

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

(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.

(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.

(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 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.

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

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

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

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

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.

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

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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

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

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

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.

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

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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.

(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

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

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)

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.

(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 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 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.

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.

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

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 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.

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.

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

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.

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 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.

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

	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	$ 19	$ (18)	$ 4	$	$ 4
Mark-to-market derivative assets (Noncurrent Assets)	34	7	25	(25)	41	12	53
Total mark-to-market derivative assets	$ 34	$ 10	$ 44	$ (43)	$ 45	$ 12	$ 57
Mark-to-market derivative liabilities (Current Liabilities)	$ (1)	$ (1)	$ (17)	$ 18	$ (1)	$	$ (1)
Mark-to-market derivative liabilities (Noncurrent liabilities)	(26)	—	(26)	25	(27)		(27)
Total mark-to-market derivative liabilities	$ (27)	$ (1)	$ (43)	$ 43	$ (28)	$ —	$ (28)
Total mark-to-market derivative net assets (liabilities)	$ 7	$ 9	$ 1	$ —	$ 17	$ 12	$ 29

(a) Generation enters into interest rate derivative contracts to economically hedge risk associated with the interest rate component of commodity positions. The characterization of the interest rate derivative contracts between the proprietary trading activity in the above table is driven by the corresponding characterization of the underlying commodity position that gives rise to the interest rate exposure. Generation does not utilize interest rate derivatives with the objective of benefiting from shifts or changes in market interest rates.
(b) Represents the netting of fair value balances with the same counterparty and any associated cash collateral.

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

	Loss on Swaps Three Months Ended March 31,		Gain (Loss) on Borrowings Three Months Ended March 31,	
Income Statement Classification	2013	2012	2013	2012
Interest expense(a)	$ (4)	$ (3)	$ (1)	$ 1

(a) For the three months ended March 31, 2013, the loss on the swaps in the table above includes $4 million reclassified to earnings, with an immaterial amount excluded from hedge effectiveness testing.

At March 31, 2013 and December 31, 2012, Exelon had $650 million of notional amounts of fixed-to-floating fair value hedges outstanding related to interest rate swaps, with unrealized gain of $44 million and $49 million, respectively, which expire in 2015. Upon merger closing, $550 million of fixed-to-floating interest rate swaps previously at Constellation with a fair value of $44 million, as of March 12, 2012, were re-designated as fair value hedges. During the three months ended March 31, 2013 and March 31, 2012, the impact of loss on the results of operations as a result of ineffectiveness from fair value hedges was immaterial.

Cash Flow Hedges. In connection with the DOE guaranteed loan for the Antelope Valley acquisition, as discussed in Note 10 — Debt and Credit Agreements, Generation entered into a floating-to-fixed forward starting interest rate swap with a notional amount of $485 million and a mandatory early termination date of April 5, 2014, by which date Generation anticipates the DOE loan to be fully drawn. The swap hedges approximately 75% of Generation's future interest rate exposure associated with the financing and was designated as a cash flow hedge. As such, the effective portion of the hedge will be recorded in other comprehensive income within Generation's Consolidated Balance Sheets, with any ineffectiveness recorded in Generation's Consolidated Statements of Operations and Comprehensive Income. Net gains (or losses) from settlement of the hedges, to the extent effective, will be amortized as an adjustment to the interest expense over the term of the DOE guaranteed loan.

Every time Generation draws down on the loan, an offsetting hedge (fixed-to-floating) is executed and a portion of the cash flow hedge, with a notional amount equal to the offsetting hedge, is de-designated and the related gains or losses going forward will be reflected in earnings, which is largely offset by the losses or gains in the offsetting hedge.

Antelope Valley received its first loan advance on April 5, 2012, and several additional advances subsequently. Generation has entered into a series of fixed-to-floating interest rate swaps with an aggregated notional amount of $273 million, 75% of the loan advance amount to offset portions of the original interest rate hedge, which are not designated as cash flow hedges. The remaining cash flow hedge has a notional amount of $211 million. At March 31, 2013, Generation's mark-to-market non-current derivative liability relating to the interest rate swaps in connection with the loan agreement to fund Antelope Valley was $23 million.

During the third quarter of 2011, a subsidiary of Constellation entered into floating-to-fixed interest rate swaps to manage a portion of the interest rate exposure for anticipated long-term borrowings to finance Sacramento PV Energy. The swaps have a total notional amount of $29 million as of March 31, 2013 and expire in 2027. After the closing of the merger with Constellation, the swaps were re-designated as cash flow hedges. At March 31, 2013, the subsidiary had an immaterial current and a $3 million non-current derivative liability related to these swaps.

During the third quarter of 2012, a subsidiary of Exelon Generation entered into a floating-to-fixed interest rate swap to manage a portion of the interest rate exposure of anticipated long-term borrowings to finance Constellation Solar Horizons. The swap has a notional amount of $29 million as of March 31, 2013 and expires in 2030. This swap is designated as a cash flow hedge. At March 31, 2013, the subsidiary had an immaterial current derivative liability and an immaterial non-current derivative asset related to the swap.

During the third quarter of 2012 and first quarter of 2013, Exelon entered into $125 million floating-to-fixed interest rate hedges to manage interest rate risks associated with anticipated future debt issuance. These swaps are designated as cash flow hedges. At March 31, 2013, Exelon had a $2 million non-current derivative asset related to these swaps.

During the three months ended March 31, 2013 and 2012, the impact on the results of operations as a result of ineffectiveness from cash flow hedges was immaterial.

Economic Hedges. At March 31, 2013, Exelon had $150 million of notional amounts of fixed-to-floating interest rate swaps that are marked-to-market, with unrealized gains of $4 million. These swaps, which were acquired as part of the merger with Constellation, expire in 2014. During the three months ended March 31, 2013 and the period from March 12 to March 31, 2012, the impact on the results of operations was immaterial.

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

Fair value accounting guidance and disclosures about offsetting assets and liabilities requires the fair value of derivative instruments to be shown in the Notes to the Consolidated Financial Statements on a gross basis, even when the derivative instruments are subject to legally enforceable master netting agreements and qualify for net presentation in the Consolidated Balance Sheet. A master netting agreement is an agreement between two counterparties that may have derivative and non-derivative contracts with each other providing for the net settlement of all referencing contracts via one payment stream, which takes place either as the contracts deliver, when collateral is requested or in the event of default. Generation's use of cash collateral is generally unrestricted unless Generation is downgraded below investment grade (i.e. to BB+ or Ba1). In the table below, Generation's energy related economic hedges and proprietary trading derivatives are shown gross and the impact of the netting of fair value balances with the same counterparty that are subject to legally enforceable master netting agreements, as well as netting of cash collateral, is aggregated in the collateral and netting column. As of March 31, 2013 and December 31, 2012, $2 million and $3 million, respectively, of cash collateral received was not offset against derivative positions because they were not associated with energy-related derivatives or as of the balance sheet date there were no positions to offset. Excluded from the tables below are economic hedges that qualify for the NPNS scope exception and other non-derivative contracts that are accounted for under the accrual method of accounting.

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

Cash collateral held by PECO and BGE must be deposited in a non affiliate major U.S. commercial bank or foreign bank with a U.S. branch office that meet certain qualifications.

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

The following table provides a summary of the derivative fair value balances recorded by the Registrants as of March 31, 2013:

	Generation				ComEd		Exelon
Derivatives	Economic Hedges(a)	Proprietary Trading	Collateral and Netting(b)	Subtotal (c)	Economic Hedges (a)(d)	Intercompany Eliminations (a)	Total Derivatives
Mark-to-market derivative assets (current assets)	$ 2,475	$ 1,989	$ (3,802)	$ 662	$ —	$ —	$ 662
Mark-to-market derivative assets with affiliate (current assets)	85	—	—	85	—	(85)	—
Mark-to-market derivative assets (noncurrent assets)	1,415	588	(1,350)	653	—	—	653
Total mark-to-market derivative assets	$ 3,975	$ 2,577	$ (5,152)	$1,400	$ —	$ (85)	$ 1,315
Mark-to-market derivative liabilities (current liabilities)	$ (2,218)	$ (1,946)	$ 3,999	$ (165)	$ (15)	$ —	$ (180)
Mark-to-market derivative liability with affiliate (current liabilities)	—	—	—	—	(85)	85	—
Mark-to-market derivative liabilities (noncurrent liabilities)	(1,005)	(553)	1,386	(172)	(60)	—	(232)
Total mark-to-market derivative liabilities	$ (3,223)	$ (2,499)	$ 5,385	$ (337)	$ (160)	$ 85	$ (412)
Total mark-to-market derivative net assets (liabilities)	$ 752	$ 78	$ 233	$1,063	$ (160)	$ —	$ 903

(a) 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, as described above.

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

(c) Current and noncurrent assets are shown net of collateral of $(98) million and $70 million, respectively, and current and noncurrent liabilities are shown net of collateral of $(99) million and $(106) million, respectively. The total cash collateral posted, net of cash collateral received and offset against mark-to-market assets and liabilities was $233 million at March 31, 2013.

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

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

The following table provides a summary of the derivative fair value balances recorded by the Registrants as of December 31, 2012:

	Generation				ComEd		Exelon
Derivatives	Economic Hedges(a)	Proprietary Trading	Collateral and Netting(b)	Subtotal (c)	Economic Hedges (a)(d)	Intercompany Eliminations (a)	Total Derivatives
Mark-to-market derivative assets (current assets)	$ 2,883	$ 2,469	$ (4,418)	$ 934	$ —	$ —	$ 934
Mark-to-market derivative assets with affiliate (current assets)	226	—	—	226	—	(226)	—
Mark-to-market derivative assets (noncurrent assets)	1,792	724	(1,638)	878	—	—	878
Mark-to-market							
Total mark-to-market derivative assets	$ 4,901	$ 3,193	$ (6,056)	$2,038	$ —	$ (226)	$ 1,812
Mark-to-market derivative liabilities (current liabilities)	$ (2,419)	$ (2,432)	$ 4,519	$ (332)	$ (18)	$ —	$ (350)
Mark-to-market derivative liability with affiliate (current liabilities)	—	—	—	—	(226)	226	—
Mark-to-market derivative liabilities (noncurrent liabilities)	(1,080)	(689)	1,568	(201)	(49)	—	(250)
Mark-to-market							
Total mark-to-market derivative liabilities	$ (3,499)	$ (3,121)	$ 6,087	$ (533)	$ (293)	$ 226	$ (600)
Total mark-to-market derivative net assets (liabilities)	$ 1,402	$ 72	$ 31	$1,505	$ (293)	$ —	$ 1,212

(a) Includes current and noncurrent assets for Generation and current and noncurrent liabilities for ComEd of $226 million related to the fair value of the five-year financial swap contract between Generation and ComEd, as described above. For Generation excludes $28 million noncurrent liability relating to an interest rate swap in connection with a loan agreement to fund Antelope Valley as discussed above.

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

(c) Current and noncurrent assets are shown net of collateral of $113 million and $201 million, respectively, and current and noncurrent liabilities are shown net of collateral of $ (214) million and $ (131) million, respectively. The total cash collateral received, net of cash collateral posted and offset against mark-to-market assets and liabilities was $31 million at December 31, 2012.

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

Cash Flow Hedges (Exelon, Generation and ComEd). As discussed previously, effective prior to the merger with Constellation, Generation de-designated all of its cash flow hedges relating to commodity price risk. 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.

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

Generation began recording prospective changes in the fair value of these instruments through current earnings from the date of de-designation. The net unrealized gains associated with the de-designated cash flow hedges prior to the merger was $1,928 million including $693 million related to the intercompany swap with ComEd. Approximately $404 million of these net pre-tax unrealized gains within accumulated OCI are expected to be reclassified from accumulated OCI during the next twelve months by Generation, including approximately $95 million related to the financial swap with ComEd. Generation expects the settlement of the majority of its cash flow hedges, including the ComEd financial swap contract, will occur during 2013 through 2014.

Exelon discontinues hedge accounting prospectively when it determines that the derivative is no longer effective in offsetting changes in the cash flows of a hedged item or when it is no longer probable that the forecasted transaction will occur. For the three months ended March 31, 2013 and 2012, amounts reclassified into earnings as a result of the discontinuance of cash flow hedges were immaterial.

The tables below provide the activity of accumulated OCI related to cash flow hedges for the three months ended March 31, 2013 and 2012, containing information about the changes in the fair value of cash flow hedges and the reclassification from accumulated OCI into results of operations. The amounts reclassified from accumulated OCI, when combined with the impacts of the actual physical power sales, result in the ultimate recognition of net revenues at the contracted price.

		Total Cash Flow Hedge OCI Activity, Net of Income Tax	
		Generation	Exelon
Three Months Ended March 31, 2013	Income Statement Location	Energy-Related Hedges	Total Cash Flow Hedges
Accumulated OCI derivative gain at December 31, 2012		$ 532(a)(c)	$ 368
Effective portion of changes in fair value		—	(1)(d)
Reclassifications from accumulated OCI to net income	Operating Revenues	(135)(b)	(58)
Accumulated OCI derivative gain at March 31, 2013		$ 397(a)(c)	$ 309

(a) Includes $58 million and $133 million of gains, net of taxes, related to the fair value of the five-year financial swap contract with ComEd, as of March 31, 2013 and December 31, 2012, respectively.
(b) Includes $75 million of losses, net of taxes, reclassified from accumulated OCI to recognize gains in net income related to the settlements of the five-year financial swap contract with ComEd.
(c) Excludes $16 million of losses and $20 million of losses net of taxes, related to interest rate swaps and treasury rate locks as of March 31, 2013 and December 31, 2012, respectively.
(d) Includes $3 million of losses, net of taxes, related to the effective portion of changes in fair value of interest rate swaps and treasury rate locks.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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Three Months Ended March 31, 2012	Income Statement Location	Total Cash Flow Hedge OCI Activity, Net of Income Tax — Generation Energy-Related Hedges	Exelon Total Cash Flow Hedges
Accumulated OCI derivative gain at December 31, 2011		$ 925(a)(c)	$ 488
Effective portion of changes in fair value		432(e)	317(d)
Reclassifications from accumulated OCI to net income	Operating Revenues	(194)(b)	(105)
Ineffective portion recognized in income	Purchased Power	3	3
Accumulated OCI derivative gain at March 31, 2012		$ 1,166(a)(c)	$ 703

(a) Includes $419 million and $420 million of gains, net of taxes, related to the fair value of the five-year financial swap contract with ComEd at March 31, 2012 and December 31, 2011, respectively.
(b) Includes a $89 million of losses, net of taxes, reclassified from accumulated OCI to recognize gains in net income related to the settlements of the five-year financial swap contract with ComEd.
(c) Excludes $12 million of gains and $10 million of losses, net of tax, related to interest rate swaps and treasury rate locks for the three months ended March 31, 2012 and the year ended December 31, 2011, respectively.
(d) Includes $12 million of losses, net of taxes, related to the effective portion of changes in fair value of interest rate swaps and treasury rate locks.
(e) Includes $88 million of gains, net of taxes, related to the effective portion of changes in fair value of the five-year financial swap contract with ComEd for the period ended March 9, 2012.

During the three months ended March 31, 2013 and 2012, Generation's former energy related cash flow hedge activity impact to pre-tax earnings based on the reclassification adjustment from accumulated OCI to earnings was a $ 223 million and a $320 million pre-tax gain, respectively. Given that the cash flow hedges had primarily consisted of forward power sales and power swaps and did not include power and gas options or sales, the ineffectiveness of Generation's cash flow hedges was primarily the result of differences between the locational settlement prices of the cash flow hedges and the hedged generating units. This price difference was actively managed through other instruments, which include financial transmission rights, whose changes in fair value are recognized in earnings each period, and auction revenue rights. Changes in cash flow hedge ineffectiveness, were losses of $ 5 million for the three months ended March 31, 2012.

Exelon's former energy-related cash flow hedge activity impact to pre-tax earnings based on the reclassification adjustment from accumulated OCI to earnings was a $ 99 million and a $173 million pre-tax gain for the three months ended March 31, 2013 and 2012, respectively. Changes in cash flow hedge ineffectiveness was losses of $ 5 million for the three months ended March 31, 2012. Neither Exelon nor Generation will incur changes in cash flow hedge ineffectiveness in future periods as all energy-related cash flow hedge positions were de-designated prior to the merger date.

Economic Hedges (Exelon and Generation). These instruments represent hedges that economically mitigate exposure to fluctuations in commodity prices and include financial options, futures, swaps, and physical forward sales and purchases but for which the fair value or cash flow hedge elections were not made. For the three months ended March 31, 2013 and 2012, the following net pre-tax mark-to-market gains (losses) of certain purchase and sale contracts were reported in operating revenues or purchased power and fuel expense at Exelon and Generation in the Consolidated Statements of Operations and Comprehensive Income and are included in "Net fair value changes related to derivatives" in Exelon's and Generation's Consolidated Statements of Cash Flows. In the tables below, "Change in fair value" represents the change in fair value of the

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

derivative contracts held at the reporting date. The “Reclassification to realized at settlement” represents the recognized change in fair value that was reclassified to realized due to settlement of the derivative during the period.

	Generation			Intercompany Eliminations	Exelon
Three Months Ended March 31, 2013	Operating Revenues	Purchased Power and Fuel	Total	Operating Revenues(a)	Total
Change in fair value	$ (485)	$ 149	$(336)	$ 7	$(329)
Reclassification to realized at settlement	(101)	34	(67)	10	(57)
Net mark-to-market gains (losses)	$ (586)	$ 183	$(403)	$ 17	$(386)

	Exelon and Generation			Intercompany Eliminations	Exelon
Three Months Ended March 31, 2012	Operating Revenues	Purchased Power and Fuel	Total	Operating Revenues(a)	Total
Change in fair value	$ 138	$ (40)	$ 98	$ 11	$ 109
Reclassification to realized at settlement	(60)	27	(33)	—	(33)
Net mark-to-market gains (losses)	$ 78	$ (13)	$ 65	$ 11	$ 76

(a) Prior to the merger, the five-year financial swap contract between Generation and ComEd was de-designated. As a result, all prospective changes in fair value are recorded to operating revenues and eliminated in consolidation.

Proprietary Trading Activities (Exelon and Generation). For the three months ended March 31, 2013 and 2012, Exelon and Generation recognized the following net unrealized mark-to-market gains (losses), net realized mark-to-market gains (losses) and total net mark-to-market gains (losses) (before income taxes) relating to mark-to-market activity on derivative instruments entered into for proprietary trading purposes. Gains and losses associated with proprietary trading are reported as operating revenue in Exelon’s and Generation’s Consolidated Statements of Operations and Comprehensive Income and are included in “Net fair value changes related to derivatives” in Exelon’s and Generation’s Consolidated Statements of Cash Flows. In the tables below, “Change in fair value” represents the change in fair value of the derivative contracts held at the reporting date. The “Reclassification to realized at settlement” represents the recognized change in fair value that was reclassified to realized due to settlement of the derivative during the period.

	Location on Income Statement	Three Months Ended March 31, 2013	2012
Change in fair value	Operating Revenues	$ (4)	$ 2
Reclassification to realized at settlement	Operating Revenues	6	1
Net mark-to-market gains (losses)	Operating Revenues	$ 2	$ 3

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

The Registrants would be exposed to credit-related losses in the event of non-performance by counterparties that enter into derivative instruments. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. For energy-related derivative instruments, Generation enters into enabling agreements that allow for payment netting with its counterparties, which reduces Generation’s exposure to counterparty risk by providing for the offset of amounts payable to the counterparty against amounts receivable from the counterparty. Typically, each enabling agreement is for a specific commodity and so, with

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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respect to each individual counterparty, netting is limited to transactions involving that specific commodity product, except where master netting agreements exist with a counterparty that allow for cross product netting. In addition to payment netting language in the enabling agreement, Generation's credit department establishes credit limits, margining thresholds and collateral requirements for each counterparty, which are defined in the derivative contracts. Counterparty credit limits are based on an internal credit review that considers a variety of factors, including the results of a scoring model, leverage, liquidity, profitability, credit ratings by credit rating agencies, and risk management capabilities. To the extent that a counterparty's margining thresholds are exceeded, the counterparty is required to post collateral with Generation as specified in each enabling agreement. Generation's credit department monitors current and forward credit exposure to counterparties and their affiliates, both on an individual and an aggregate basis.

The following tables provide information on Generation's credit exposure for all derivative instruments, NPNS, and applicable payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of March 31, 2013. The tables further delineate that exposure by credit rating of the counterparties and provide guidance on the concentration of credit risk to individual counterparties. The figures in the tables below do not include credit risk exposure from uranium procurement contracts or exposure through RTOs, ISOs, NYMEX, ICE and Nodal commodity exchanges, further discussed in ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK. Additionally, the figures in the tables below do not include exposures with affiliates, including net receivables with ComEd, PECO and BGE of $44 million, $59 million and $25 million, respectively.

Rating as of March 31, 2013	Total Exposure Before Credit Collateral	Credit Collateral	Net Exposure	Number of Counterparties Greater than 10% of Net Exposure	Net Exposure of Counterparties Greater than 10% of Net Exposure
Investment grade	$ 1,459	$ 184	$ 1,275	1	$ 387
Non-investment grade	49	29	20	—	—
No external ratings					
Internally rated — investment grade	403	5	398	1	252
Internally rated — non-investment grade	44	1	43	—	—
Total	$ 1,955	$ 219	$ 1,736	2	$ 639

Net Credit Exposure by Type of Counterparty	As of March 31, 2013
Investor-owned utilities, marketers and power producers	$ 515
Energy cooperatives and municipalities	824
Financial institutions	352
Other	45
Total	$ 1,736

ComEd's power procurement contracts provide suppliers with a certain amount of unsecured credit. The credit position is based on forward market prices compared to the benchmark prices. The benchmark prices are the forward prices of energy projected through the contract term and are set at the point of supplier bid submittals. If the forward market price of energy exceeds the benchmark price, the suppliers are required to post collateral for the secured credit portion after adjusting for any unpaid deliveries and unsecured credit allowed under the contract. The unsecured credit used by the suppliers represents ComEd's net credit exposure. As of March 31, 2013, ComEd's credit exposure to suppliers was immaterial.

ComEd is permitted to recover its costs of procuring energy through the Illinois Settlement Legislation as well as the ICC-approved procurement tariffs. ComEd's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. See Note 3 — Regulatory Matters of the Exelon 2012 Form 10-K for further information.

PECO's supplier master agreements that govern the terms of its electric supply procurement contracts, which define a supplier's performance assurance requirements, allow a supplier to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's lowest credit rating from the major credit rating agencies and the supplier's tangible net worth. The credit position is based on the initial market price, which is the forward price of energy on the day a transaction is executed, compared to the current forward price curve for energy. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post collateral to the extent the credit exposure is greater than the supplier's unsecured credit limit. As of March 31, 2013, PECO's net credit exposure with suppliers was immaterial and did not exceed the allowed unsecured credit levels.

PECO is permitted to recover its costs of procuring electric supply through its PAPUC-approved DSP Program. PECO's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. See Note 5 - Regulatory Matters for further information.

PECO's natural gas procurement plan is reviewed and approved annually on a prospective basis by the PAPUC. PECO's counterparty credit risk under its natural gas supply and asset management agreements is mitigated by its ability to recover its natural gas costs through the PGC, which allows PECO to adjust rates quarterly to reflect realized natural gas prices. PECO does not obtain collateral from suppliers under its natural gas supply and asset management agreements. As of March 31, 2013, PECO had immaterial credit exposure under its natural gas supply and asset management agreements with investment grade suppliers.

BGE is permitted to recover its costs of procuring energy through the MDPSC-approved procurement tariffs. BGE's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. See Note 5 — Regulatory Matters for further information.

BGE's full requirement wholesale electric power agreements that govern the terms of its electric supply procurement contracts, which define a supplier's performance assurance requirements, allow a supplier, or its guarantor, to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's lowest credit rating from the major credit rating agencies and the supplier's tangible net worth, subject to an unsecured credit cap. The credit position is based on the initial market price, which is the forward price of energy on the day a transaction is executed, compared to the current forward price curve for energy. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post collateral to the extent the credit exposure is greater than the supplier's unsecured credit limit. The seller's credit exposure is calculated each business day. As of March 31, 2013, BGE had no net credit exposure to suppliers.

BGE's regulated gas business is exposed to market-price risk. This market-price risk is mitigated by BGE's recovery of its costs to procure natural gas through a gas cost adjustment clause approved by the MDPSC. BGE does make off-system sales after BGE has satisfied its customers' demands, which are not covered by the gas cost adjustment clause. At March 31, 2013, BGE had credit exposure of $8 million related to off-system sales which is mitigated by parental guarantees, letters of credit, or right to offset clauses within other contracts with those third party suppliers.

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Collateral and Contingent-Related Features (Exelon, Generation, ComEd, PECO and BGE)

As part of the normal course of business, Generation routinely enters into physical or financially settled contracts for the purchase and sale of electric capacity, energy, fuels, emissions allowances and other energy-related products. Certain of Generation's derivative instruments contain provisions that require Generation to post collateral. Generation also enters into commodity transactions on exchanges (i.e., NYMEX, ICE). The exchanges act as the counterparty to each trade. Transactions on the exchanges must adhere to comprehensive collateral and margining requirements. This collateral may be posted in the form of cash or credit support with thresholds contingent upon Generation's credit rating from each of the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. These credit-risk-related contingent features stipulate that if Generation were to be downgraded or lose its investment grade credit rating (based on its senior unsecured debt rating), it would be required to provide additional collateral. This incremental collateral requirement allows for the offsetting of derivative instruments that are assets with the same counterparty, where the contractual right of offset exists under applicable master netting agreements. In the absence of expressly agreed-to provisions that specify the collateral that must be provided, collateral requested will be a function of the facts and circumstances of the situation at the time of the demand. In this case, Generation believes an amount of several months of future payments (i.e., capacity payments) rather than a calculation of fair value is the best estimate for the contingent collateral obligation, which has been factored into the disclosure below.

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

Credit-Risk Related Contingent Feature		**March 31, 2013**
Gross Fair Value of Derivative Contracts Containing this Feature(a)	**Offsetting Fair Value of In-the-Money Contracts Under Master Netting Arrangements(b)**	**Net Fair Value of Derivative Contracts Containing This Feature(c)**
($1,521)	$1,246	($275)

Credit-Risk Related Contingent Feature		**December 31, 2012**
Gross Fair Value of Derivative Contracts Containing this Feature(a)	**Offsetting Fair Value of In-the-Money Contracts Under Master Netting Arrangements(b)**	**Net Fair Value of Derivative Contracts Containing This Feature(c)**
($1,849)	$1,426	($423)

(a) Amount represents the gross fair value of out-of-the-money derivative contracts containing credit-risk-related contingent features that are not fully collateralized by posted cash collateral on an individual, contract-by-contract basis ignoring the effects of master netting agreements.
(b) Amount represents the offsetting fair value of in-the-money derivative contracts under legally enforceable master netting agreements with the same counterparty, which reduces the amount of any liability for which a Registrant could potentially be required to post collateral.
(c) Amount represents the net fair value of out-of-the-money derivative contracts containing credit-risk related contingent features after considering the mitigating effects of offsetting positions under master netting arrangements and reflects the actual net liability upon which any potential contingent collateral obligations would be based.

Generation has cash collateral posted of $467 million and letters of credit posted of $142 million and cash collateral held of $236 million and letters of credit held of $48 million as of March 31, 2013 and cash collateral posted of $527 million and letters of credit posted of $563 million and cash collateral held of $499 million and letters of credit held of $45 million at December 31, 2012 for counterparties with derivative positions. In the event of a credit downgrade below investment grade (i.e. to BB+ or Ba1), Exelon Generation Company, LLC could be required to post additional collateral of $1,747 million as of March 31, 2013 and $2,007 million as of

December 31, 2012. These amounts represent the potential additional collateral required after giving consideration to offsetting derivative and non-derivative positions under master netting agreements.

Generation's and Exelon's interest rate swaps contain provisions that, in the event of a merger, if Generation's debt ratings were to materially weaken, it would be in violation of these provisions, resulting in the ability of the counterparty to terminate the agreement prior to maturity. Collateralization would not be required under any circumstance. Termination of the agreement could result in a settlement payment by Exelon or the counterparty on any interest rate swap in a net liability position. The settlement amount would be equal to the fair value of the swap on the termination date. As of March 31, 2013, Generation's and Exelon's swaps were in an asset position, with a fair value of $17 million and $29 million, respectively.

See Note 21 — Segment Information of the Exelon 2012 Form 10-K for further information regarding the letters of credit supporting the cash collateral.

Generation entered into SFCs with certain utilities, including PECO and BGE, with one-sided collateral postings only from Generation. If market prices fall below the benchmark price levels in these contracts, the utilities are not required to post collateral. However, when market prices rise above the benchmark price levels, counterparty suppliers, including Generation, are required to post collateral once certain unsecured credit limits are exceeded. Under the terms of the financial swap contract between Generation and ComEd, if a party is downgraded below investment grade by Moody's or S&P, collateral postings would be required by that party depending on how market prices compare to the benchmark price levels. Under the terms of the financial swap contract, collateral postings will never exceed $200 million from either ComEd or Generation. Under the terms of ComEd's standard block energy contracts, collateral postings are one-sided from suppliers, including Generation, should exposures between market prices and benchmark prices exceed established unsecured credit limits outlined in the contracts. As of March 31, 2013, ComEd held neither cash nor letters of credit for the purpose of collateral from suppliers in association with energy procurement contracts. Under the terms of ComEd's annual renewable energy contracts, collateral postings are required to cover a fixed value for RECs only. In addition, under the terms of ComEd's long-term renewable energy contracts, collateral postings are required from suppliers for both RECs and energy. The REC portion is a fixed value and the energy portion is one-sided from suppliers should the forward market prices exceed contract prices. As of March 31, 2013, ComEd held approximately $19 million in the form of cash and letters of credit as margin for both the annual and long-term REC obligations. See Note 3 — Regulatory Matters of the Exelon 2012 Form 10-K for further information.

PECO's natural gas procurement contracts contain provisions that could require PECO to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon PECO's credit rating from the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. As of March 31, 2013, PECO was not required to post collateral for any of these agreements. If PECO lost its investment grade credit rating as of March 31, 2013, PECO could have been required to post approximately $36 million of collateral to its counterparties.

PECO's supplier master agreements that govern the terms of its DSP Program contracts do not contain provisions that would require PECO to post collateral.

BGE's full requirements wholesale power agreements that govern the terms of its electric supply procurement contracts do not contain provisions that would require BGE to post collateral.

BGE's natural gas procurement contracts contain provisions that could require BGE to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon BGE's credit rating from the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. As of March 31, 2013, BGE was not required to post collateral for any of these agreements. If BGE lost its investment grade credit rating as of March 31, 2013, BGE could have been required to post approximately $127 million of collateral to its counterparties.

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

Short-Term Borrowings

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

The Registrants had the following amounts of commercial paper borrowings outstanding as of March 31, 2013 and December 31, 2012:

Commercial Paper Borrowings	March 31, 2013	December 31, 2012
Exelon Corporate	$ —	$ —
Generation	—	—
ComEd	220	—
PECO	—	—
BGE	—	—

Credit Facilities

Exelon had bank lines of credit under committed credit facilities at March 31, 2013 for short-term financial needs, as follows:

Type of Credit Facility	Amount(a) (In billions)	Expiration Dates	Capacity Type
Exelon Corporate			
Syndicated Revolver	$ 0.5	August 2017	Letters of credit and cash
Generation			
Syndicated Revolver	5.3	August 2017	Letters of credit and cash
Bilateral	0.3	December 2015 and March 2016	Letters of credit and cash
Bilateral	0.1	January 2015	Letters of credit
ComEd			
Syndicated Revolver	1.0	March 2018	Letters of credit and cash
PECO			
Syndicated Revolver	0.6	August 2017	Letters of credit and cash
BGE			
Syndicated Revolver	0.6	August 2017	Letters of credit and cash
Total	$ 8.4		

(a) Excludes additional credit facility agreements for Generation, ComEd, PECO and BGE with aggregate commitments of $50 million, $34 million, $34 million and $5 million, respectively, arranged with minority and community banks located primarily within ComEd's, PECO's and BGE's service territories. These facilities expire on October 19, 2013 and are solely utilized to issue letters of credit. As of March 31, 2013, letters of credit issued under these agreements totaled $25 million, $26 million, $21 million and $1 million, respectively.

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

As of March 31, 2013, there were no borrowings under the Registrants' credit facilities.

On March 14, 2013, ComEd extended its unsecured revolving credit facility with aggregate bank commitments of $1.0 billion. Under this facility, ComEd may issue letters of credit in the aggregate amount of up to $500 million. The credit agreement expires on March 28, 2018, and ComEd may request another one-year extension of that term. The credit facility also allows ComEd to request increases in the aggregate commitments of up to an additional $500 million. Any such extension or increases are subject to the approval of the lenders party to the credit agreement in their sole discretion. Costs incurred to extend the facility for ComEd were not material.

Borrowings under Exelon Corporate's, Generation's, ComEd's, PECO's and BGE's credit agreements bear interest at a rate based upon either the prime rate or a LIBOR-based rate, plus an adder based upon the registrants credit rating. Exelon Corporate, Generation, ComEd, PECO and BGE have adders of 27.5, 27.5, 27.5, 0.0 and 7.5 basis points for prime based borrowings and 127.5, 127.5, 127.5, 100.0 and 107.5 basis points for LIBOR-based borrowings. The maximum adders for prime rate borrowings and LIBOR-based rate borrowings are 65 basis points and 165 basis points, respectively. The credit agreement also requires each entity to pay a facility fee based upon the aggregate commitments under the agreement. The fee varies depending upon the respective credit ratings of each entity.

On January 23, 2013, Generation entered into a two year $75 million bilateral letter of credit facility with a bank. The credit agreement expires in January 2015. This facility will solely be utilized by Generation to issue letters of credit.

Long-Term Debt

Issuance of Long-Term Debt

During the three months ended March 31, 2013, the following long-term debt was issued:

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Generation	Upstream Gas Lending Agreement	2.21%	July 22, 2016	$ 3	Used to fund Upstream gas activities
Generation	DOE Project Financing	2.72 - 2.81%	January 5, 2037	146	Funding for Antelope Valley Solar Development

During the three months ended March 31, 2012, there were no issuances of long-term debt.

Retirement of Current and Long-Term Debt

During the three months ended March 31, 2013, the following long-term debt was retired:

Company	Type	Interest Rate	Maturity	Amount
Generation	Kennett Square Capital Lease	7.83%	September 20, 2020	$ 1

On April 15, 2013, ComEd retired $125 million aggregate principal of its 7.625% Series 92 First Mortgage Bonds due April 15, 2013.

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

During the three months ended March 31, 2012, the following long-term debt was retired:

Company	Type	Interest Rate	Maturity	Amount
ComEd	First Mortgage Bond Series 98	6.15%	March 15, 2012	$ 450
Generation	Kennett Square Capital Lease	7.83%	September 20, 2020	$ 1

Accounts Receivable Agreement

PECO is party to an agreement with a financial institution under which it transferred an undivided interest, adjusted daily, in its accounts receivable designated under the agreement in exchange for proceeds of $210 million, which is classified as a short-term note payable on Exelon's and PECO's Consolidated Balance Sheets. As of March 31, 2013 and December 31, 2012, the financial institution's undivided interest in Exelon's and PECO's gross accounts receivable was equivalent to $322 million and $289 million, respectively, which represents the financial institution's interest in PECO's eligible receivables as calculated under the terms of the agreement. The agreement requires PECO to maintain eligible receivables at least equivalent to the financial institution's undivided interest. Upon termination or liquidation of this agreement, the financial institution is entitled to recover up to $210 million plus the accrued yield payable from its undivided interest in PECO's receivables. The amended agreement terminates on August 30, 2013 unless extended in accordance with its terms. As of March 31, 2013, PECO was in compliance with the requirements of the agreement. In the event the agreement is not extended, PECO has sufficient short-term liquidity and may seek alternate financing.

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

The effective income tax rate from continuing operations varies from the U.S. Federal statutory rate principally due to the following:

For the Three Months Ended March 31, 2013	Exelon	Generation(a)	ComEd(a)	PECO	BGE
U.S. Federal statutory rate	35.0%	35.0%	35.0%	35.0%	35.0%
Increase (decrease) due to:					
State income taxes, net of Federal income tax benefit	68.0	82.0	5.8	2.8	5.7
Qualified nuclear decommissioning trust fund income	62.0	(192.3)	—	—	—
Domestic production activities deduction	(2.4)	7.4	—	—	—
Tax exempt income	(1.6)	4.8	—	—	—
Health care reform legislation	2.2	—	(0.5)	—	0.4
Amortization of investment tax credit, net deferred taxes	(25.8)	75.6	0.4	(0.1)	(0.2)
Plant basis differences	(24.9)	—	0.9	(6.7)	(0.6)
Production tax credits and other credits	(21.7)	67.2	—	—	—
Other	7.4	(74.1)	0.1	0.1	0.4
Effective income tax rate	98.2%	5.6%	41.7%	31.1%	40.7%

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

For the Three Months Ended March 31, 2012	Exelon(b)	Generation(b)	ComEd	PECO	BGE(c)
U.S. Federal statutory rate	35.0%	35.0%	35.0%	35.0%	35.0%
Increase (decrease) due to:					
State income taxes, net of Federal income tax benefit	(27.4)	1.2	5.9	3.4	4.4
Qualified nuclear decommissioning trust fund income	16.0	14.7	—	—	—
Domestic production activities deduction	(1.2)	(1.2)	—	—	—
Tax exempt income	(0.4)	(0.4)	—	—	—
Health care reform legislation	0.2	—	0.4	—	—
Amortization of investment tax credit, net deferred taxes	(0.8)	(0.5)	(0.3)	(0.3)	0.9
Plant basis differences	(3.0)	—	—	(3.5)	2.7
Production tax credits and other credits	(0.5)	(3.1)	—	—	—
Fines and Penalties	13.3	11.9	—	—	—
Merger expenses(d)	13.2	—	—	—	(8.5)
Other	(0.3)	0.5	0.2	(0.1)	0.3
Effective income tax rate	44.1%	58.1%	41.2%	34.5%	34.8%

(a) Generation and ComEd recognized a loss before income taxes for the three months ended March 31, 2013. As a result, positive percentages represent an income tax benefit for Generation and ComEd for the three months ended March 31, 2013.

(b) Exelon activity for the three months ended March 31, 2012 includes the results of Constellation and BGE for March 12, 2012 — March 31, 2012. Generation activity for the three months ended March 31, 2012 includes the results of Constellation for March 12, 2012 — March 31, 2012.

(c) BGE activity represents the activity for the three months ended March 31, 2013 and 2012. BGE recognized a loss before income taxes for the three months ended March 31, 2012. As a result, positive percentages represent an income tax benefit for BGE for the three months ended March 31, 2012.

(d) Prior to the close of the merger, the Registrants recorded the applicable taxes on merger transaction costs assuming the merger would not be completed. Upon closing of the merger, the Registrants reversed such taxes for those merger transaction costs that were determined to be non tax-deductible upon successful completion of a merger.

Accounting for Uncertainty in Income Taxes

Exelon, Generation, ComEd, PECO, and BGE have $1,656 million, $903 million, $334 million, $44 million, and $0 million, of unrecognized tax benefits as of March 31, 2013, respectively, and $1,024 million, $876 million, $67 million, $44 million and $0 million, of unrecognized tax benefits as of December 31, 2012, respectively. The increase in Exelon's and ComEd's unrecognized tax benefits is primarily attributable to the like-kind exchange position discussed below.

Other Income Tax Matters

Involuntary Conversion, Like-Kind Exchange and Competitive Transition Charges

1999 Sale of Fossil Generating Assets (Exelon and ComEd). Exelon, through its ComEd subsidiary, took two positions on its 1999 income tax return to defer approximately $2.8 billion of tax gain on the sale of ComEd's fossil generating assets. Exelon deferred approximately $1.6 billion of the gain under the involuntary conversion provisions of the IRC. Exelon believed that it was economically compelled to dispose of ComEd's fossil generating plants as a result of the Illinois Act and that the proceeds from the sale of the fossil plants were properly reinvested in qualifying replacement property such that the gain could be deferred over the lives of the replacement property under the involuntary conversion provisions. The remaining approximately $1.2 billion of the gain was deferred by reinvesting the proceeds from the sale in qualifying replacement property under the like-kind exchange provisions of the IRC. The like-kind exchange replacement property purchased by Exelon included interests in three municipal-owned electric generation facilities which were properly leased back to the municipalities. The IRS disagreed with both positions and asserted that the entire gain of approximately $2.8 billion was taxable in 1999.

Competitive Transition Charges (Exelon, ComEd, and PECO). Exelon contended that the Illinois Act and the Competition Act resulted in the taking of certain of ComEd's and PECO's assets used in their respective businesses of providing electricity services in their defined service areas. Exelon filed refund claims with the IRS taking the position that CTCs collected during ComEd's and PECO's transition periods represent compensation for that taking and, accordingly, were excludible from taxable income as proceeds from an involuntary conversion. The tax basis of property acquired with the funds provided by the CTCs would be reduced such that the benefits of the position are temporary in nature. The IRS disallowed the refund claims for the 1999-2001 tax years.

Status of Involuntary Conversion and CTC Positions. In the second quarter of 2010, the IRS offered to settle the disagreement over the involuntary conversion and CTC positions. Exelon concluded, based on that offer, that it had sufficient new information that a remeasurement of the involuntary conversion and CTC positions was required in accordance with applicable accounting standards. As a result of the required remeasurement, Exelon recorded $65 million (after-tax) of interest expense, of which $36 million (after-tax) and $22 million (after-tax) were recorded at ComEd and PECO, respectively. ComEd also recorded a current tax expense of $70 million offset with a tax benefit recorded at Generation of $70 million. In the third quarter of 2010, Exelon and the IRS reached a nonbinding, preliminary agreement to settle Exelon's involuntary conversion on terms consistent with the settlement offer received in the second quarter. As a result of the preliminary agreement, Exelon and ComEd eliminated any liability for unrecognized tax benefits and established a current tax payable to the IRS. Exelon paid $302 million in late 2010 in advance of the final settlement and the assessment. In November 2012, the IRS and Exelon finalized and executed definitive agreements to resolve Exelon's involuntary conversion and CTC positions.

Status of Like-Kind Exchange Position. Exelon has been unable to reach agreement with the IRS regarding the dispute over the like kind exchange position. The IRS has asserted that the Exelon purchase and leaseback transaction is substantially similar to a leasing transaction, known as a SILO, which the IRS does not respect as the acquisition of an ownership interest in property. A SILO is a "listed transaction" that the IRS has identified as a potentially abusive tax shelter under guidance issued in 2005. Accordingly, the IRS has asserted that the sale of the fossil plants followed by the purchase and leaseback of the municipal owned generation facilities does not qualify as a like-kind exchange and the gain on the sale is fully subject to tax. The IRS has also asserted a penalty of approximately $86 million for a substantial understatement of tax.

Exelon disagrees with the IRS and continues to believe that its like-kind exchange transaction is not the same as or substantially similar to a SILO. Exelon expects to initiate litigation in 2013 to contest the IRS's disallowance of the like-kind exchange position. Although Exelon has been and remains willing to settle the disagreement on terms commensurate with the hazards of litigation, Exelon does not believe a settlement is possible. Because Exelon believed, as of December 31, 2012, that it was more-likely-than-not that Exelon would prevail in litigation, Exelon and ComEd had no liability for unrecognized tax benefits with respect to the like kind exchange position.

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

In accordance with applicable accounting standards, Exelon is required to assess whether it is more-likely-than-not that it will prevail in litigation. Exelon continues to believe that its transaction is not a SILO and that it has a strong case on the merits. However, in light of the Consolidated Edison decision and Exelon's current determination that settlement is unlikely, Exelon has concluded that subsequent to December 31, 2012, it is no longer more-likely-than-not that its position will be sustained. As a result, in the first quarter of 2013 Exelon recorded a non-cash charge to earnings of approximately $265 million, which represents the amount of interest expense (after-tax) and incremental state income tax expense for periods through March 31, 2013 that would be payable in the event that Exelon is unsuccessful in litigation. Of this amount, approximately $170 million was recorded at ComEd. Exelon intends to hold ComEd harmless from any unfavorable impacts of the after-tax interest amounts on ComEd's equity. As such, ComEd recorded on its consolidated balance sheet as of March 31, 2013, a $172 million receivable and non-cash equity contributions from Exelon. Exelon and ComEd will continue to accrue interest on the uncertain tax position, and the charges arising from future interest accruals are not expected to be material to the annual operating earnings of Exelon or ComEd. In addition, ComEd will continue to record a receivable and non-cash equity contribution from Exelon in amounts equal to the additional interest recorded by ComEd on the uncertain tax position. The IRS also continues to assert an $86 million penalty for a substantial understatement of tax with respect to the like-kind exchange position. Exelon continues to believe that it is unlikely that the penalty assertion will ultimately be sustained and therefore no liability for the penalty has been recorded.

This determination for accounting purposes does not alter Exelon's intent to aggressively litigate the issue through appeals, if necessary, which could take three to five years. Exelon currently expects to initiate the litigation in the United States Tax Court, whose decisions are not controlled by the Federal Circuit's decision in Consolidated Edison.

As of March 31, 2013, in the event of a fully successful IRS challenge to Exelon's like-kind exchange position, the potential tax and after-tax interest, exclusive of penalties, that could become currently payable may be as much as $840 million, of which approximately $302 million would be attributable to ComEd after consideration of Exelon's agreement to hold ComEd harmless, and the balance at Exelon. Litigation could take several years such that the estimated cash and interest impacts would likely change by a material amount.

Accounting for Generation Repairs (Exelon and Generation).

On April 30, 2013, the IRS issued guidance that will facilitate the determination of the appropriate tax treatment of costs incurred to repair electric generation assets. Exelon and Generation will assess its impact and expect to file a request for change in method of tax accounting for repair costs beginning with its 2014 taxable year.

12. Nuclear Decommissioning (Exelon and Generation)

Nuclear Decommissioning Asset Retirement Obligations

Generation has a legal obligation to decommission its nuclear power plants following the expiration of their operating licenses. To estimate its decommissioning obligation related to its nuclear generating stations, Generation uses a probability-weighted, discounted cash flow model which, on a unit-by-unit basis, considers multiple outcome scenarios that include significant estimates and assumptions, and are based on decommissioning cost studies, cost escalation rates, probabilistic cash flow models and discount rates. Generation generally updates its ARO annually during the third quarter, unless circumstances warrant more frequent updates, based on its review of updated cost studies and its annual evaluation of cost escalation factors and probabilities assigned to various scenarios.

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

The following table provides a rollforward of the nuclear decommissioning ARO reflected on Exelon's and Generation's Consolidated Balance Sheets from December 31, 2012 to March 31, 2013:

Nuclear decommissioning ARO at December 31, 2012(a)	$4,741
Accretion expense	64
Costs incurred to decommission retired plants	(1)
Nuclear decommissioning ARO at March 31, 2013(a)	$4,804

(a) Includes $10 million as the current portion of the ARO at March 31, 2013 and December 31, 2012, which is included in other current liabilities on Exelon's and Generation's Consolidated Balance Sheets.

Nuclear Decommissioning Trust Fund Investments

NDT funds have been established for each generating station unit to satisfy Generation's nuclear decommissioning obligations. NDT funds established for a particular unit may not be used to fund the decommissioning obligations of any other unit.

The NDT funds associated with the former ComEd, former PECO and former AmerGen units have been funded with amounts collected from ComEd customers, PECO customers and the previous owners of the former AmerGen plants, respectively. Based on an ICC order, ComEd ceased collecting amounts from its customers to pay for decommissioning costs. PECO currently collects funds, in revenues, for decommissioning the former PECO nuclear plants through regulated rates, and these collections are expected to continue through the operating lives of the plants. The amounts collected from PECO customers are remitted to Generation and deposited into the NDT funds. Every five years, PECO files a rate adjustment with the PAPUC that reflects PECO's calculations of the estimated amount needed to decommission each of the former PECO units based on updated fund balances and estimated decommissioning costs. The rate adjustment is used to determine the amount collectible from PECO customers. The most recent rate adjustment occurred on January 1, 2013, and the effective rates currently yield annual collections of $24 million. The next five-year adjustment is expected to be reflected in rates charged to PECO customers effective January 1, 2018. With respect to the former AmerGen units, Generation does not collect any amounts, nor is there any mechanism by which Generation can seek to collect additional amounts, from customers. Apart from the contributions made to the NDT funds from amounts collected from ComEd and PECO customers, Generation has not made contributions to the NDT funds.

Any shortfall of funds necessary for decommissioning, determined for each generating station unit, is ultimately required to be funded by Generation. Generation has recourse to collect additional amounts from PECO customers related to a shortfall of NDT funds for the former PECO units, subject to certain limitations and thresholds, as prescribed by an order from the PAPUC. Generally, PECO will not be allowed to collect amounts associated with the first $50 million of any shortfall of trust funds, on an aggregate basis for all former PECO units, compared to decommissioning obligations, as well as 5% of any additional shortfalls. The initial $50 million and up to 5% of any additional shortfalls would be borne by Generation. No recourse exists to collect additional amounts from ComEd customers for the former ComEd units or from the previous owners of the former AmerGen units. With respect to the former ComEd and PECO units, any funds remaining in the NDTs after decommissioning has been completed are required to be refunded to ComEd's or PECO's customers, subject to certain limitations that allow sharing of excess funds with Generation related to the former PECO units. With respect to the former AmerGen units, Generation retains any funds remaining in the funds after decommissioning.

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

At March 31, 2013 and December 31, 2012, Exelon and Generation had NDT fund investments totaling $7,559 million and $7,248 million, respectively. The following table provides unrealized gains (losses) on NDT funds for the three months ended March 31, 2013 and 2012:

	Three Months Ended March 31, 2013	Three Months Ended March 31, 2012
Net unrealized gains on decommissioning trust funds — Regulatory Agreement Units(a)	$ 195	$ 247
Net unrealized gains on decommissioning trust funds — Non-Regulatory Agreement Units(b)(c)	64	65

(a) Net unrealized gains related to Generation's NDT funds associated with Regulatory Agreement Units are included in regulatory liabilities on Exelon's Consolidated Balance Sheets and noncurrent payables to affiliates on Generation's Consolidated Balance Sheets.

(b) Excludes $2 and $35 million of net unrealized gains related to the Zion Station pledged assets for the three months ended March 31, 2013 and 2012, respectively. Net unrealized gains related to Zion Station pledged assets are included in the payable for Zion Station decommissioning on Exelon's and Generation's Consolidated Balance Sheets.

(c) Net unrealized gains related to Generation's NDT funds associated with Non-Regulatory Agreement Units are included within Other, net in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

Interest and dividends on NDT fund investments are recognized when earned and are included in Other, net in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. Interest and dividends earned on the NDT fund investments for the Regulatory Agreement Units, which are subject to regulatory accounting, are eliminated within Other, net in Exelon's and Generation's Consolidated Statement of Operations and Comprehensive Income.

See Note 3 and Note 22 of the Exelon 2012 Form 10-K for information regarding regulatory liabilities at ComEd and PECO and intercompany balances between Generation, ComEd and PECO reflecting the obligation to refund to customers any decommissioning-related assets in excess of the related decommissioning obligations.

Zion Station Decommissioning. On September 1, 2010, Generation completed an Asset Sale Agreement (ASA) with EnergySolutions Inc. and its wholly owned subsidiaries, EnergySolutions, LLC (EnergySolutions) and ZionSolutions under which ZionSolutions has assumed responsibility for decommissioning Zion Station, which is located in Zion, Illinois and ceased operation in 1998. On January 7, 2013, EnergySolutions announced that it had entered a definitive acquisition agreement to be acquired by another Company. Generation reviewed the acquisition as it relates to the ASA to decommission Zion Station. Based on that review, Generation determined that the acquisition will not adversely impact decommissioning activities under the ASA. See Note 13 of the Exelon 2012 Form 10-K for information regarding the specific treatment of assets, including NDT funds, and decommissioning liabilities transferred in the transaction.

On July 14, 2011, three people filed a purported class action lawsuit in the United States District Court for the Northern District of Illinois naming ZionSolutions and Bank of New York Mellon as defendants and seeking, among other things, an accounting for use of NDT funds, an injunction against the use of NDT funds, the appointment of a trustee for the NDT funds, and the return of NDT funds to customers of ComEd to the extent legally entitled thereto. If the plaintiffs prevail on the merits of their claims, some or all of the NDT funds may no longer be available to ZionSolutions for decommissioning Zion Station, in which case, the contractual arrangement would require ZionSolutions to utilize a line of credit to complete the decommissioning. In addition, the appointment of a NDT fund trustee in this matter could impact Generation's future decommissioning activities at other stations by setting a precedent for the appointment of trustees for NDT funds. On July 20, 2012, ZionSolutions and Bank of New York Mellon filed a motion to dismiss the amended complaint for failing to state a claim. The matter is currently under review by the court.

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

ZionSolutions is subject to certain restrictions on its ability to request reimbursements from the Zion Station NDT funds as defined within the ASA. Therefore, the transfer of the Zion Station assets did not qualify for asset sale accounting treatment and, as a result, the related NDT funds were reclassified to pledged assets for Zion Station decommissioning within Generation's and Exelon's Consolidated Balance Sheets and will continue to be measured in the same manner as prior to the completion of the transaction. Additionally, the transferred ARO for decommissioning was replaced with a payable to ZionSolutions in Generation's and Exelon's Consolidated Balance Sheets. Changes in the value of the Zion Station NDT assets, net of applicable taxes, will be recorded as a change in the payable to ZionSolutions. At no point will the payable to ZionSolutions exceed the project budget of the costs remaining to decommission Zion Station. Any Zion Station NDT funds remaining after the completion of all decommissioning activities will be returned to ComEd customers. Generation has retained its obligation to transfer the SNF at Zion Station to the DOE for ultimate disposal and has a liability of approximately $79 million, which is included within the nuclear decommissioning ARO at March 31, 2013. Generation also has retained NDT assets to fund its obligation to maintain and transfer the SNF at Zion Station. The following table provides the pledged assets and payable to ZionSolutions, and withdrawals by ZionSolutions at March 31, 2013 and December 31, 2012:

	Exelon and Generation	
	March 31, 2013	December 31, 2012
Carrying value of Zion Station pledged assets	$ 580	$ 614
Payable to Zion Solutions(a)	531	564
Current portion of payable to Zion Solutions(b)	159	132
Withdrawals by Zion Solutions to pay decommissioning costs(c)	371	335

(a) Excludes a liability recorded within Generation's Consolidated Balance Sheets related to the tax obligation on the unrealized activity associated with the Zion Station NDT Funds. The NDT Funds will be utilized to satisfy the tax obligations as gains and losses are realized.
(b) Included in other current liabilities within Generation's Consolidated Balance Sheets.
(c) Cumulative withdrawals since September 1, 2010.

NRC Minimum Funding Requirements. NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that funds will be available in specified minimum amounts to decommission the facility at the end of its life. On April 1, 2013, Generation submitted its NRC-required biennial decommissioning funding status report as of December 31, 2012. As of December 31, 2012, Generation provided adequate funding assurance for all of its units, including Limerick Unit 1, where Generation has in place a $115 million parent guarantee to cover the NRC minimum funding assurance requirements.

On January 31, 2013, Generation received a letter from the NRC indicating that the NRC has identified potential “apparent violations” of its regulations because of alleged inaccuracies in the Decommissioning Fund Status reports for 2005, 2006, 2007, and 2009. The NRC asserted that Generation's status reports deliberately reflected cost estimates for decommissioning its nuclear plants that were less than what the NRC says are the minimum amounts required by NRC regulations. Generation met with the NRC on April 30, 2013 for a pre-decisional enforcement conference to provide additional information to explain why Generation believes that it complied with the regulatory requirements and did not deliberately or otherwise provide incomplete or inaccurate information in its decommissioning funding status reports. While Generation does not believe that any sanction is appropriate, the ultimate outcome of this proceeding including the amount of a potential fine or sanction, if any, is uncertain. Generation anticipates that the NRC will issue its findings sometime this year. The January 31, 2013 letter from the NRC does not take issue with Generation's current funding status, and as reflected in Generation's April 1, 2013 decommissioning funding status report referenced above, Generation continues to provide adequate funding assurance for each of its units.

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

13. Retirement Benefits (Exelon, Generation, ComEd, PECO and BGE)

Exelon sponsors defined benefit pension plans and other postretirement benefit plans for essentially all Generation, ComEd, PECO, BGE and BSC employees.

Defined Benefit Pension and Other Postretirement Benefits

During the first quarter of 2013, Exelon received an updated valuation of its legacy Exelon pension and other postretirement benefit obligations to reflect actual census data as of January 1, 2013. This valuation resulted in an increase to the pension obligation of $8 million and a decrease to the other postretirement benefit obligation of $39 million. Additionally, accumulated other comprehensive loss decreased by approximately $75 million (after tax) and regulatory assets increased by $93 million. The updated valuation for legacy Constellation plans will be completed in the second quarter of 2013.

The following tables present the components of Exelon's net periodic benefit costs for the three months ended March 31, 2013 and 2012. The 2013 pension benefit cost for all plans is calculated using an expected long-term rate of return on plan assets of 7.50% and a discount rate of 3.92%. The 2013 other postretirement benefit cost is calculated using an expected long-term rate of return on plan assets of 6.45% for funded plans and a discount rate of 4.00% for all plans. Legacy Constellation other postretirement benefit plans are not funded. A portion of the net periodic benefit cost is capitalized within the Consolidated Balance Sheets.

	Pension Benefits Three Months Ended March 31,		Other Postretirement Benefits Three Months Ended March 31,	
	2013	2012	2013	2012
Service cost	$ 80	$ 61	$ 41	$ 37
Interest cost	163	164	48	51
Expected return on assets	(253)	(232)	(33)	(29)
Amortization of:				
Transition obligation	—	—	—	3
Prior service cost (benefit)	3	4	(4)	(3)
Actuarial loss	140	106	20	19
Net periodic benefit cost	$ 133	$ 103	$ 72	$ 78

The amounts below were included in capital additions and operating and maintenance expense during the three months ended March 31, 2013 and 2012, for Generation's, ComEd's, PECO's, BGE's and BSC's allocated portion of the pension and postretirement benefit plan costs.

	Three Months Ended March 31,	
Pension and Other Postretirement Benefit Costs	2013	2012
Generation	$ 87	$ 81
ComEd	77	69
PECO	11	13
BGE(a)	13	16
BSC(b)	17	14

(a) BGE's pension and postretirement benefit costs for the three months ended March 31, 2012 include $12 million of costs incurred prior to the closing of Exelon's merger with Constellation on March 12, 2012. These amounts are not included in Exelon's net periodic benefit costs for the three months ended March 31, 2012 shown in the first table of the Defined Benefit Pension and Other Postretirement Benefits section above.

(b) These amounts primarily represent amounts billed to Exelon's subsidiaries through intercompany allocations. These amounts are not included in the Generation, ComEd, PECO or BGE amounts above.

Management considers various factors when making pension funding decisions, including actuarially determined minimum contribution requirements under ERISA, contributions required to avoid benefit restrictions and at-risk status as defined by the Pension Protection Act of 2006, management of the pension obligation and regulatory implications. Exelon expects to contribute $255 million to its qualified pension plans in 2013, of which Generation, ComEd, PECO and BGE will contribute $113 million, $116 million, $11 million and $0 million, respectively. Unlike the qualified pension plans, Exelon's non-qualified pension plans are not funded. Exelon expects to make non-qualified pension plan benefit payments of $79 million in 2013, of which Generation, ComEd, PECO, and BGE will make payments of $6 million, $1 million, $1 million, and $2 million, respectively.

Unlike qualified pension plans, other postretirement plans are not subject to regulatory minimum contribution requirements. Exelon's management has historically considered several factors in determining the level of contributions to its other postretirement benefit plans, including levels of benefit claims paid and regulatory implications (amounts deemed prudent to meet regulator expectations and best assure continued recovery). In 2013, Exelon anticipates funding its other postretirement benefit plans based on the funding considerations discussed above, with the exception of those plans previously sponsored by Constellation and AmerGen, which remain unfunded. Exelon expects to make other postretirement benefit plan contributions, including benefit payments related to unfunded plans, of approximately $292 million in 2013, of which Generation, ComEd, PECO, and BGE expect to contribute $117 million, $114 million, $22 million, and $18 million, respectively.

Plan Assets

Investment Strategy. On a regular basis, Exelon evaluates its investment strategy to ensure that plan assets will be sufficient to pay plan benefits when due. As part of this ongoing evaluation, Exelon may make changes to its targeted asset allocation and investment strategy.

Exelon has developed and implemented an investment strategy for its qualified pension plans that has reduced the volatility of its pension assets relative to its pension liabilities. Exelon is likely to continue to gradually increase the liability hedging portfolio as the funded status of its plans improves. The overall objective is to achieve attractive risk-adjusted returns that will balance the liquidity requirements of the plans' liabilities while striving to minimize the risk of significant losses. This investment strategy would tend to result in a lower expected rate of return on plan assets in future years. Trust assets for Exelon's other postretirement plans are managed in a diversified investment strategy that prioritizes maximizing liquidity and returns while minimizing asset volatility.

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

Defined Contribution Savings Plans

The Registrants participate in various 401(k) defined contribution savings plans that are sponsored by Exelon. The plans are qualified under applicable sections of the IRC and allow employees to contribute a portion of their pre-tax income in accordance with specified guidelines. All Registrants match a percentage of the employee contributions up to certain limits. The following table presents the matching contributions to the savings plans during the three months ended March 31, 2013 and 2012:

	Three Months Ended March 31,	
Savings Plan Matching Contributions	2013	2012
Exelon	$ 22	$ 16
Generation	11	8
ComEd	5	4
PECO	2	2
BGE(a)	2	2
BSC(b)	2	1

(a) BGE’s matching contributions for the three months ended March 31, 2012 include $1 million of costs incurred prior to the closing of Exelon’s merger with Constellation on March 12, 2012, which is not included in Exelon’s matching contributions for the three months ended March 31, 2012.

(b) These amounts primarily represent amounts billed to Exelon’s subsidiaries through intercompany allocations. These costs are not included in the Generation, ComEd, PECO or BGE amounts above.

14. Stock-Based Compensation Plans (Exelon, Generation, ComEd, PECO and BGE)

Exelon grants stock-based awards through its LTIP, which primarily includes stock options, restricted stock units and performance share awards. At March 31, 2013, there were approximately 16 million shares authorized for issuance under the LTIP. For the three months ended March 31, 2013 and 2012, exercised and distributed stock-based awards were primarily issued from authorized but unissued common stock shares.

The Compensation Committee of Exelon’s Board of Directors changed the mix of awards granted under the LTIP in 2013 by eliminating stock options in favor of the use of full value shares, consisting of performance shares and restricted stock. The performance share awards granted in 2013 will vest at the end of a three-year performance period. The performance share awards granted in 2012 and earlier had a one-year performance period and vested ratably over three years. To address the reduction in annual award opportunity resulting from the transition to a three-year performance period, the Compensation Committee also approved a one-time grant of performance share transition awards in 2013, which will vest one-third after one year, with the remaining balance vesting over a two-year performance period.

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

The following table presents the stock-based compensation expense included in Exelon's Consolidated Statements of Operations and Comprehensive Income for the three months ended March 31, 2013 and 2012:

Components of Stock-Based Compensation Expense	Three Months Ended March 31, 2013	Three Months Ended March 31, 2012
Performance share awards	$ 16	$ 16
Stock options	1	7
Restricted stock units	20	19
Other stock-based awards	1	1
Total stock-based compensation expense included in operating and maintenance expense	38	43
Income tax benefit	(15)	(16)
Total after-tax stock-based compensation expense	$ 23	$ 27

The following table presents stock-based compensation expense (pre-tax) for the three months ended March 31, 2013 and 2012:

Subsidiaries	Three Months Ended March 31, 2013	Three Months Ended March 31, 2012
Generation	$ 15	$ 14
ComEd	2	5
PECO	2	3
BGE(a)	2	2
BSC(b)	17	19
Total(c)	$ 38	$ 43

(a) BGE's stock-based compensation expense (pre-tax) for the three months ended March 31, 2012 includes $2 million of cost incurred prior to the closing of Exelon's merger with Constellation on March 12, 2012. This amount is not included in Exelon's stock-based compensation expense for the three months ended March 31, 2012 shown in the table titled Components of Stock-Based Compensation Expense above.
(b) These amounts primarily represent amounts billed to Exelon's subsidiaries through intercompany allocations. These amounts are not included in the Generation, ComEd, PECO and BGE amounts above.
(c) The stock-based compensation expense (pre-tax) for the three months ended March 31, 2013 reflects the impact of changes to the retirement eligibility requirements for employees participating in the LTIP. In addition, the stock-based compensation expense at ComEd reflects the adoption of the ComEd Key Manager Long-Term Performance Program in 2013 for certain employees, which is not consider stock-based compensation expense under the applicable authoritative guidance. In 2012, these employees participated in the Exelon Restricted Stock Award Program.

There were no significant stock-based compensation costs capitalized during the three months ended March 31, 2013 and 2012.

Stock Options

Non-qualified stock options are granted under the LTIP with exercise prices equal to the fair market value of the underlying stock at the date of grant. Generally, the stock options vest ratably over a four-year vesting period and expire ten years from the date of grant.

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

There were no stock options granted in 2013. The Compensation Committee eliminated stock option grants by changing the mix of long-term incentives for Senior Vice Presidents (SVPs) and higher officers from 75% performance shares and 25% stock options to 67% performance shares and 33% restricted stock units ("RSUs").

At March 31, 2013, $5 million of total unrecognized compensation costs related to nonvested stock options are expected to be recognized over the remaining weighted-average period of 2.1 years.

Restricted Stock Units

Restricted stock units are granted under the LTIP with the majority being settled in a specific number of shares of common stock after the service condition has been met. The corresponding cost of services is measured based on the grant date fair value of the restricted stock unit issued. The requisite service period for restricted stock units is generally three to five years. However, certain restricted stock unit awards become fully vested upon the employee reaching retirement-eligibility.

At March 31, 2013, Exelon had obligations related to outstanding restricted stock units not yet settled of $48 million, which are included in common stock in Exelon's Consolidated Balance Sheets. As of March 31, 2013, Exelon had no obligations related to outstanding restricted stock units that will be settled in cash. During the three months ended March 31, 2013 and 2012, Exelon settled restricted stock units with a fair value totaling $22 million and $20 million, respectively. At March 31, 2013, $94 million of total unrecognized compensation costs related to nonvested restricted stock units are expected to be recognized over the remaining weighted-average period of 2.6 years.

Performance Share and Performance Share Transition Awards

Performance share awards are granted under the LTIP with the 2013 performance share awards being settled 50% in common stock and 50% in cash at the end of the three-year performance period except for awards granted to executive vice presidents and higher officers that may be settled 100% in cash if certain ownership requirements are satisfied. The 2012 performance share awards are being settled 50% in common stock and 50% in cash over the three-year vesting term with executive vice presidents and higher officers receiving 100% cash if certain ownership requirements are satisfied. The performance shares granted prior to 2012 generally vest and settle over a three-year period with the holders receiving shares of common stock and/or cash annually during the vesting period.

The one-time 2013 performance share transition awards, which provide an opportunity to earn an award contingent on company performance, will be settled 50% in common stock and 50% in cash, except for awards granted to executive vice presidents and higher officers that may be settled 100% in cash if certain ownership requirements are satisfied. One-third of the award vests and is payable after a one-year performance period while the remaining two-thirds vests and is payable after a two-year performance period.

The payout of the 2013 performance share awards and one-time performance share transition awards are based on the Company's performance against specific operational and financial goals set annually during the respective performance periods. As a result, the 2013 performance share awards have been divided into equal tranches for the purpose of expense recognition as though the respective award were multiple awards; with each tranche representing a corresponding fiscal year. The one-time performance share transition awards have also been divided into multiple tranches for the purpose of expense recognition. One tranche reflects the one-third of the awards that vests and are payable after a one-year period. The two-thirds of the one-time performance share transition awards that are subject to a two-year performance period have also been divided into equal tranches; with each tranche representing a corresponding fiscal year. The grant date for each tranche of the 2013 performance share and one-time performance share transition awards is the date in which the performance goals for that fiscal year are approved and communicated, which typically occurs at the corresponding January Compensation Committee meeting.

The 2013 performance share awards and one-time performance share transition awards are recorded at fair value at the grant dates for each tranche, with the estimated grant date fair value based on the expected payout of the award, which may range from 50% to 150% of the payout target. The 2013 performance share awards also include a total shareholder return modifier (TSR) that may increase or decrease the award up to 25% and an individual performance modifier (IPM) that can decrease the award by up to 50% or increase the award by up to 10% for senior vice presidents and higher officers or up to 20% for vice presidents. The one-time performance share transition award is not affected by either TSR or the IPM.

The common stock portion of the performance share and one-time performance share transition awards is considered an equity award being valued based on Exelon's stock price on the grant date. The cash portion of the awards is considered a liability award which is remeasured each reporting period based on Exelon's current stock price. As the value of the common stock and cash portions of the awards are based on Exelon's stock price during the performance period, coupled with changes in the total shareholder return modifier and expected payout of the award, the compensation costs are subject to volatility until payout is established.

The 2012 performance share awards are recorded at fair value at the date of grant with the estimated grant date fair value based on the expected payout of the award, which may range from 75% to 125% of the payout target. The common stock portion is considered an equity award with the 75% payout floor being valued based on Exelon's stock price on the grant date. The cash portion of the award is considered a liability award with the 75% payout floor being remeasured each reporting period based on Exelon's current stock price. The expected payout in excess of the 75% floor for the equity and liability portions are remeasured each reporting period based on Exelon's current stock price and changes in the expected payout of the award; therefore these portions of the award are subject to volatility until the payout is established.

For nonretirement-eligible employees, stock-based compensation costs are recognized over the vesting period of three years using the graded-vesting method. For performance share and one-time performance share transition awards granted to retirement-eligible employees, the value of the performance shares in recognized ratably over the vesting period, which is the year of grant.

During the three months ended March 31, 2013 and 2012, Exelon settled performance shares with a fair value totaling $22 million and $18 million, respectively, of which $9 million and $3 million was paid in cash, respectively. As of March 31, 2013, $47 million of total unrecognized compensation costs related to nonvested performance shares are expected to be recognized over the remaining weighted-average period of 2.7 years. In addition, as of March 31, 2013, $29 million of total unrecognized compensation costs related to nonvested one-time performance share transition awards are expected to be recognized over the remaining weighted-average period of 1.8 years.

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

15. Changes in Accumulated Other Comprehensive Income (Exelon, Generation, and PECO)

The following table presents changes in accumulated other comprehensive income (loss) by component for three months ended March 31, 2013:

	Gains and (Losses) on Cash Flow Hedges	Unrealized Gains and (Losses) on Marketable Securities	Pension and Non-Pension Postretirement Benefit Plan items	Foreign Currency Items	AOCI of Equity Investments	Total
Exelon(a)						
Beginning balance	$ 368	$ —	$ (3,137)	$ —	$ 2	$(2,767)
OCI before reclassifications	—	(1)	76	(1)	26	100
Amounts reclassified from AOCI(b)	(58)	—	50	—	2	(6)
Net current-period OCI	(58)	(1)	126	(1)	28	94
Ending balance	$ 310	$ (1)	$ (3,011)	$ (1)	$ 30	$(2,673)
Generation(a)						
Beginning balance	$ 513	$ (1)	$ (19)	$ —	$ 20	$ 513
OCI before reclassifications	5	(1)	—	(1)	26	29
Amounts reclassified from AOCI(b)	(135)	—	—	—	2	(133)
Net current-period OCI	(130)	(1)	—	(1)	28	(104)
Ending balance	$ 383	$ (2)	$ (19)	$ (1)	$ 48	$ 409
PECO(a)						
Beginning balance	$ —	$ 1	$ —	$ —	$ —	$ 1
OCI before reclassifications	—	—	—	—	—	—
Amounts reclassified from AOCI(b)	—	—	—	—	—	—
Net current-period OCI	—	—	—	—	—	—
Ending balance	$ —	$ 1	$ —	$ —	$ —	$ 1

(a) All amounts are net of tax. Amounts in parenthesis represent a decrease in accumulated other comprehensive income.
(b) See next table for details about these reclassifications.

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

The following table presents amounts reclassified out of AOCI to Net Income during the three months ended March 31, 2013:

Details about AOCI components	Items reclassified out of AOCI(a) Exelon	Generation	ComEd	PECO	BGE	Affected line item in the statement where Net Income is presented
Gains and (losses) on cash flow hedges						
Energy related hedges	$ 99	$ 223	$ —	$ —	$—	Operating revenues
Other cash flow hedges	(1)	—	—	—	—	Interest expense
	98	223	—	—	—	Total before tax
	(40)	(88)	—	—	—	Tax (expense)
	$ 58	$ 135	$ —	$ —	$—	Net of tax
Amortization of pension and other postretirement benefit plan items						
Actuarial gains/ (losses)	$ (83)	—	—	—	—	(b)
	(83)	—	—	—	—	Total before tax
	33	—	—	—	—	Tax benefit
	$ (50)	$ —	$ —	$ —	$—	Net of tax
Equity investments						
Capital activity	$ (3)	$ (3)	$ —	$ —	$—	Equity in losses of unconsolidated affiliates
	(3)	(3)	—	—	—	Total before tax
	1	1	—	—	—	Tax benefit
	$ (2)	$ (2)	$ —	$ —	$—	Net of tax
Total reclassifications for the period	$ 6	$ 133	$ —	$ —	$—	Net of Tax

(a) All amounts are net of tax. Amounts in parenthesis represent a decrease in net income.
(b) This accumulated other comprehensive income component is included in the computation of net periodic pension and OPEB cost (see Note 13 — Retirement Benefits for additional details).

16. Earnings Per Share and Equity (Exelon)

Earnings per Share

Diluted earnings per share is calculated by dividing net income by the weighted average number of shares of common stock outstanding, including shares to be issued upon exercise of stock options, performance share awards and restricted stock outstanding under Exelon's LTIPs considered to be common stock equivalents. The following table sets forth the components of basic and diluted earnings per share and shows the effect of these stock options, performance share awards and restricted stock on the weighted average number of shares outstanding (in millions) used in calculating diluted earnings per share:

	Three Months Ended March 31, 2013	2012
Net (loss) income	$ (4)	$ 200
Weighted average common shares outstanding — basic	855	705
Assumed exercise and/or distributions of stock based awards	—	2
Weighted average common shares outstanding — diluted	855	707

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

For the three months ended March 31, 2013 in which there was a net loss to common stockholders, no potentially dilutive securities are included in the calculation of diluted loss per share, as inclusion of these securities would have reduced the net loss per share. For the three months ended March 31, 2012, the number of stock options not included in the calculation of diluted common shares outstanding due to their antidilutive effect was approximately 11 million.

Under share repurchase programs, 35 million shares of common stock are held as treasury stock with a cost of $2.327 billion as of March 31, 2013. In 2008, Exelon management decided to defer indefinitely any share repurchases.

Preferred Securities

PECO has $87 million of cumulative preferred securities that are redeemable at its option at any time for the redemption price established when each series of securities were issued. 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. The redemption premium will be reflected as a direct charge to retained earnings in PECO's Consolidated Balance Sheet in the second quarter of 2013.

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

The following is an update to the current status of commitments and contingencies set forth in Note 19 of the Exelon 2012 Form 10-K.

Commitments

Energy Commitments

As of March 31, 2013, Generation's short- and long-term commitments relating to the purchases from unaffiliated utilities and others of energy, capacity and transmission rights, are as indicated in the following table:

	Net Capacity Purchases(a)	Power-Related Purchases(b)	Transmission Rights Purchases(c)	Purchased Energy from CENG	Total
2013	$ 274	$ 60	$ 22	$ 584	$ 940
2014	356	76	26	588	1,046
2015	351	36	13	—	400
2016	266	19	2	—	287
2017	203	4	2	—	209
Thereafter	472	3	34	—	509
Total	$ 1,922	$ 198	$ 99	$ 1,172	$3,391

(a) Net capacity purchases include PPAs and other capacity contracts including those that are accounted for as operating leases. Amounts presented in the commitments represent Generation's expected payments under these arrangements at March 31, 2013, net of fixed capacity payments expected to be received by Generation under contracts to resell such acquired capacity to third parties under long-term capacity sale contracts. These capacity payments represent the fixed, or pre-determined, payment for output from contracted generation facilities. Output in this context generally includes products such as energy, capacity, and various ancillary services associated with generating facilities. Expected payments include certain capacity charges which are contingent on plant availability.
(b) Power-Related Purchases include firm REC purchase agreements. The table excludes renewable energy purchases that are contingent in nature.
(c) Transmission rights purchases include estimated commitments for additional transmission rights that will be required to fulfill firm sales contracts.

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

In connection with Constellation's comprehensive agreement with EDF in October 2010, Constellation's and EDF's existing power purchase agreements with CENG were modified to be unit-contingent through the end of their original term in 2014. Under these agreements, CENG has the ability to fix the energy price on a forward basis by entering into monthly energy hedge transactions for a portion of the future sale, while any unhedged portions will be provided at market prices by default. Additionally, beginning in 2015 and continuing to the end of the life of the respective plants, Generation agreed to purchase 50.01% of the available output of CENG's nuclear plants at market prices. Generation discloses in the table above commitments to purchase from CENG at fixed prices. All commitments to purchase at market prices, which include all purchases subsequent to December 31, 2014, are excluded from the table. Generation continues to own a 50.01% membership interest in CENG that is accounted for as an equity method investment. See Note 5 — Investment in Constellation Energy Nuclear Group, LLC for more details on this arrangement.

ComEd's, PECO's and BGE's electric supply procurement, curtailment services, REC and AEC purchase commitments as of March 31, 2013 are as follows:

		Expiration within					
	Total	2013	2014	2015	2016	2017	2018 and beyond
ComEd							
Electric supply procurement(a)	$1,103	$367	$323	$136	$137	$140	$ —
Renewable energy and RECs(b)	1,632	49	66	74	76	82	1,285
PECO							
Electric supply procurement(c)	1,073	704	309	60	—	—	—
AECs	27	10	5	2	2	2	6
BGE							
Electric supply procurement(d)	1,191	651	466	74	—	—	—
Curtailment services	140	37	46	41	16	—	—

(a) ComEd entered into various contracts for the procurement of electricity that started to expire in 2012, and will continue to expire through 2017. ComEd is permitted to recover its electric supply procurement costs from retail customers with no mark-up. See Note 5 — Regulatory Matters for additional information.

(b) ComEd entered into 20-year contracts for renewable energy and RECs beginning June 2012. ComEd is permitted to recover its renewable energy and REC costs from retail customers with no mark-up. 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. See Note 5 — Regulatory Matters for additional information.

(c) PECO entered into various contracts for the procurement of electric supply to serve its default service customers that expire between 2013 and 2015. PECO is permitted to recover its electric supply procurement costs from default service customers with no mark-up in accordance with its PAPUC-approved DSP Programs. See Note 5 — Regulatory Matters for additional information.

(d) BGE entered into various contracts for the procurement of electricity that expire between 2013 and 2015. The cost of power under these contracts is recoverable under MDPSC approved fuel clauses. See Note 5 — Regulatory Matters for additional information.

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

Fuel Purchase Obligations

In addition to the energy commitments described above, Generation has commitments to purchase fuel supplies for nuclear and fossil generation (and with respect to coal, commitments to sell coal). PECO and BGE have commitments to purchase natural gas, related to transportation, storage capacity and services to serve customers in their gas distribution service territory. As of March 31, 2013, these net commitments were as follows:

		Expiration within					
	Total	2013	2014	2015	2016	2017	2018 and beyond
Generation	$8,622	$940	$1,239	$1,256	$1,021	$1,068	$ 3,098
PECO	461	141	103	75	49	15	78
BGE	588	104	72	50	48	48	266

Other Purchase Obligations

The Registrants’ other purchase obligations as of March 31, 2013, which primarily represent commitments for services, materials and information technology, are as follows:

		Expiration within					
	Total	2013	2014	2015	2016	2017	2018 and beyond
Exelon	$817	$204	$196	$127	$61	$58	$ 171
Generation	570	135	141	107	41	38	108
ComEd	14	2	12	—	—	—	—
PECO	47	18	19	1	1	1	7
BGE	—	—	—	—	—	—	—

Construction Commitments

Generation has committed to the construction of a solar PV facility in Los Angeles County, California. The first portion of the project began operations in December 2012, with additional phases to come online and an expectation of full commercial operation in December 2013. Generation’s estimated remaining commitment for the project is $304 million for 2013.

Refer to Note 3 of the Exelon 2012 Form 10-K for information on investment programs associated with regulatory mandates, such as ComEd’s Infrastructure Investment Plan under EIMA, PECO’s Smart Meter Procurement and Installation Plan and BGE’s comprehensive smart grid initiative.

Constellation Merger Commitments

In 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 was 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.

On February 17, 2012, the MDPSC approved the merger with conditions. Many of the conditions were reflective of the settlement agreements described above. The following costs were recognized after the closing of the merger and are included in Exelon's, Generation's and BGE's Consolidated Statements of Operations and Comprehensive Income for the year ended December 31, 2012. See Note 4 of the Exelon 2012 Form 10-K for additional information on the merger.

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

Description	Payment Period	BGE	Generation	Exelon	Statement of Operations Location
BGE rate credit of $100 per residential customer(a)	Q2 2012	$113	$ —	$ 113	Revenues
Customer investment fund to invest in energy efficiency and low-income energy assistance to BGE customers	2012 to 2014	—	—	113.5	O&M Expense
Contribution for renewable energy, energy efficiency or related projects in Baltimore	2012 to 2014	—	—	2	O&M Expense
Charitable contributions at $7 million per year for 10 years	2012 to 2021	28	35	70	O&M Expense
State funding for offshore wind development projects	Q2 2012	—	—	32	O&M Expense
Miscellaneous tax benefits	Q2 2012	(2)	—	(2)	Taxes Other Than Income
Total		$139	$ 35	$328.5	

(a) Exelon made a $66 million equity contribution to BGE in the second quarter of 2012 to fund the after-tax amount of the rate credit as directed in the MDPSC order approving the merger transaction.

Contingencies

Commercial Commitments

The Registrants' commercial commitments as of March 31, 2013, representing commitments potentially triggered by future events were as follows:

	Exelon	Generation	ComEd	PECO	BGE
Letters of credit (non-debt)(a)	$ 1,573	$ 1,522	$ 26	$ 22	$ 1
Guarantees	7,550(b)	1,848(c)	209(d)	181(e)	252(f)
Nuclear insurance premiums(g)	2,494	2,494	—	—	—
Total commercial commitments	$11,617	$ 5,864	$ 235	$203	$253

(a) Non-debt letters of credit maintained to provide credit support for certain transactions as requested by third parties.
(b) Primarily reflects parental guarantees issued on behalf of Generation to allow the flexibility needed to conduct business with counterparties without having to post other forms of collateral. Also reflects guarantees issued to ensure performance under specific contracts, preferred securities of financing trusts, property leases, indemnifications, NRC minimum funding assurance requirements and $211 million on behalf of CENG nuclear generating facilities for credit support and miscellaneous guarantees. The estimated net exposure for obligations under commercial transactions covered by these guarantees was $1.1 billion at March 31, 2013, which represents the total amount Exelon could be required to fund based on March 31, 2013 market prices.
(c) Primarily reflects guarantees issued to ensure performance under energy marketing and other specific contracts and $211 million on behalf of CENG nuclear generating facilities for credit support. The estimated net exposure for obligations under commercial transactions covered by these guarantees was $0.4 billion at March 31, 2013, which represents the total amount Generation could be required to fund based on March 31, 2013 market prices.
(d) Primarily reflects full and unconditional guarantees of $200 million Trust Preferred Securities of ComEd Financing III which is a 100% owned finance subsidiary of ComEd.

(e) Primarily reflects full and unconditional guarantees of $178 million Trust Preferred Securities of PECO Trust III and IV which is a 100% owned finance subsidiary of PECO.
(f) Primarily reflects full and unconditional guarantees of $250 million Trust Preferred Securities of BGE Capital Trust II which is a 100% owned finance subsidiary of BGE.
(g) Represents the maximum amount that Generation would be required to pay for retrospective premiums in the event of nuclear disaster at any domestic site under the Secondary Financial Protection pool as required under the Price-Anderson Act as well as the current aggregate annual retrospective premium obligation that could be imposed by NEIL. See the Nuclear Insurance section within this note for additional details on Generation's nuclear insurance premiums.

Nuclear Insurance (Exelon and Generation)

The Price-Anderson Act requires mandatory participation in a retrospective rating plan for power reactors (currently 104 reactors) resulting in $12.2 billion in funds available for public liability claims for any single incident at any power reactor site that exceeds the primary level of financial protection currently required ($375 million). Additionally, Generation is also required each year to report to the NRC the current levels and sources of property insurance that demonstrates Generation possesses sufficient financial resources to stabilize and decontaminate a reactor and reactor station site in the event of an accident. The property insurance maintained for each facility is currently provided through insurance policies purchased from NEIL, an industry mutual insurance company of which Generation is a member. Premiums paid to NEIL by its members are subject to assessment for adverse loss experience (the retrospective premium obligation). The maximum combined retrospective premium amount that Generation could be required to pay due to participation in the Price-Anderson Act retrospective rating plan for power reactors and the NEIL retrospective premium obligation is $2.2 billion, which is included above in the Commercial Commitments table. See the Nuclear Insurance section within Note 19 of the Exelon 2012 Form 10-K for additional details on Generation's nuclear insurance premiums.

Indemnifications Related to Sale of Sithe (Exelon and Generation)

On January 31, 2005, subsidiaries of Generation completed a series of transactions that resulted in Generation's sale of its investment in Sithe. Specifically, subsidiaries of Generation consummated the acquisition of Reservoir Capital Group's 50% interest in Sithe and subsequently sold 100% of Sithe to Dynegy, Inc. (Dynegy).

The estimated maximum possible exposure to Exelon related to the guarantees provided as part of the sales transaction to Dynegy was approximately $200 million at March 31, 2013. Generation believes that it is remote that it will be required to make any additional payments under the guarantee, and currently has no recorded liabilities associated with this guarantee. Generation expects that the exposure covered by this guarantee will expire in 2014. The guarantee is included above in the Commercial Commitments table under performance guarantees.

Indemnifications Related to Sale of TEG and TEP (Exelon and Generation)

On February 9, 2007, Tamuin International Inc. (TII), a wholly owned subsidiary of Generation, sold its 49.5% ownership interests in TEG and TEP to a subsidiary of AES Corporation for $95 million in cash plus certain purchase price adjustments. In connection with the transaction, Generation entered into a guarantee agreement under which Generation guarantees the timely payment of TII's obligations to the subsidiary of AES Corporation pursuant to the terms of the purchase and sale agreement relating to the sale of TII's ownership interests. Generation would be required to perform in the event that TII does not pay any obligation covered by the guarantee that is not otherwise subject to a dispute resolution process. Generation's maximum obligation under the guarantee is $95 million as of March 31, 2013. Generation believes that it is remote that it will be required to make payments under the guarantee and has not recorded a liability associated with this guarantee.

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

The exposures covered by this guarantee expired in part during 2008. Generation expects that the remaining exposure will expire in the third quarter of 2013. The guarantee of $95 million is included above in the Commercial Commitments table under performance guarantees.

Environmental Issues

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

ComEd, PECO and BGE have identified sites where former MGP activities have or may have resulted in actual site contamination. For almost all of these sites, ComEd, PECO or BGE is one of several PRPs that may be responsible for ultimate remediation of each location.

- ComEd has identified 42 sites, 15 of which have been approved for cleanup by the Illinois EPA or the U.S. EPA and 27 that are currently under some degree of active study and/or remediation. ComEd expects the majority of the remediation at these sites to continue through at least 2016.
- PECO has identified 26 sites, 16 of which have been approved for cleanup by the PA DEP and 10 that are currently under some degree of active study and/or remediation. PECO expects the majority of the remediation at these sites to continue through at least 2019.
- BGE has identified 13 former gas manufacturing or purification sites that it currently owns or owned at one time through a predecessor's acquisition. Two gas manufacturing sites require some level of remediation and ongoing monitoring under the direction of the MDE. The required costs at these two sites are not considered material. One gas purification site is in the initial stages of investigation at the direction of the MDE.

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

As of March 31, 2013 and December 31, 2012, the Registrants had accrued the following undiscounted amounts for environmental liabilities in other current liabilities and other deferred credits and other liabilities within their respective Consolidated Balance Sheets:

March 31, 2013	Total Environmental Investigation and Remediation Reserve	Portion of Total Related to MGP Investigation and Remediation
Exelon	$ 337	$ 296
Generation	30	—
ComEd	259	252
PECO	47	44
BGE	1	—

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December 31, 2012	Total Environmental Investigation and Remediation Reserve	Portion of Total Related to MGP Investigation and Remediation
Exelon	$ 338	$ 298
Generation	30	—
ComEd	260	254
PECO	47	44
BGE	1	—

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

Water Quality

Section 316(b) of the Clean Water Act. Section 316(b) requires that the cooling water intake structures at electric power plants reflect the best technology available to minimize adverse environmental impacts, and is implemented through state-level NPDES permit programs. All of Generation's and CENG's power generation facilities with cooling water systems are subject to the regulations. Facilities without closed-cycle recirculating systems (e.g., cooling towers) are potentially most affected. For Generation, those facilities are Clinton, Dresden, Eddystone, Fairless Hills, Gould Street, Handley, Mountain Creek, Mystic 7, Oyster Creek, Peach Bottom, Quad Cities, Riverside, Salem and Schuylkill. For CENG, those facilities are Calvert Cliffs, Nine Mile Point Unit 1 and R.E. Ginna.

On March 28, 2011, the U.S. EPA issued the proposed regulation under Section 316(b). The proposal does not require closed-cycle cooling (e.g., cooling towers) as the best technology available to address impingement and entrainment. The proposal provides the state permitting agency with discretion to determine the best technology available to limit entrainment (drawing aquatic life into the plants cooling system) mortality, including application of a cost-benefit test and the consideration of a number of site-specific factors. After consideration of these factors, the state permitting agency may require closed cycle cooling, an alternate technology, or determine that the current technology is the best available. The proposed rule also imposes limits on impingement (trapping aquatic life on screens) mortality, which likely will be accomplished by the installation of screens or another technology at the intake. Exelon filed comments on the proposed regulation on August 18, 2011, stating its support for a number of its provisions (e.g., cooling towers not required as best technology available, and the use of site-specific and cost benefit analysis) while also noting a number of technical provisions that require revision to take into account existing unit operations and practices within the industry.

In June 2012, the U.S. EPA published two Notices of Data Availability (NODA) seeking public comment on alternate compliance technologies for impingement and the use of a public opinion survey to calculate the so-called "non-use" benefits of the rule. Exelon filed comments for each NODA, supporting the additional flexibility afforded by the impingement NODA, and opposing the NODA relating to calculation of non-use benefits due to its inaccurate and unreliable methodologies that would artificially inflate the benefits of proposed technologies that would otherwise not be cost-effective. On July 18, 2012, the U.S. EPA announced that it had agreed to extend the court approved Settlement Agreement to extend the deadline to issue a final rule until June 27, 2013. Until the rule is finalized, the state permitting agencies will continue to apply their best professional judgment to address impingement and entrainment.

Salem and Other Power Generation Facilities. In June 2001, the NJDEP issued a renewed NPDES permit for Salem, allowing for the continued operation of Salem with its existing cooling water system. NJDEP advised PSEG, in July 2004 that it strongly recommended reducing cooling water intake flow commensurate with closed-cycle cooling as a compliance option for Salem. PSEG submitted an application for a renewal of the permit on February 1, 2006. In the permit renewal application, PSEG analyzed closed-cycle cooling and other options and demonstrated that the continuation of the Estuary Enhancement Program, an extensive environmental restoration program at Salem, is the best technology to meet the Section 316(b) requirements. PSEG continues to operate Salem under the approved June 2001 NPDES permit while the NPDES permit renewal application is being reviewed. If the final permit or Section 316(b) regulations ultimately requires the retrofitting of Salem's cooling water intake structure to reduce cooling water intake flow commensurate with closed-cycle cooling, Exelon's and Generation's share of the total cost of the retrofit and any resulting interim replacement power would likely be in excess of $430 million, based on a 2006 estimate, and would result in increased depreciation expense related to the retrofit investment.

It is unknown at this time whether the NJDEP permit programs will require closed-cycle cooling at Salem. In addition, the economic viability of Generation's other power generation facilities, as well as CENG's, without closed-cycle cooling water systems will be called into question by any requirement to construct cooling towers. Should the final rule not require the installation of cooling towers, and retain the flexibility afforded the state permitting agencies in applying a cost benefit test and to consider site-specific factors, the impact of the rule would be minimized even though the costs of compliance could be material to Generation and CENG.

Given the uncertainties associated with the requirements that will be contained in the final rule, Generation cannot predict the eventual outcome or estimate the effect that compliance with any resulting Section 316(b) or interim state requirements will have on the operation of its and CENG's generating facilities and its future results of operations, cash flows and financial position.

Groundwater Contamination. In October 2007, a subsidiary of Constellation entered into a consent decree with the MDE relating to groundwater contamination at a third party facility that was licensed to accept fly ash, a byproduct generated by coal-fired plants. The consent decree required the payment of a $1 million penalty, remediation of groundwater contamination resulting from the ash placement operations at the site, replacement of drinking water supplies in the vicinity of the site, and monitoring of groundwater conditions. Prior to the merger, Constellation recorded a liability in its Consolidated Balance Sheets of approximately $23 million to comply with the consent decree. The remaining liability as of March 31, 2013, is approximately $3 million. In addition, a private party has asserted claims relating to groundwater contamination. The company believes that these claims are without merit and is vigorously contesting them.

Air Quality

Cross State Air Pollution Rule (CSAPR). On July 11, 2008, the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit Court) vacated the CAIR, which had been promulgated by the U.S. EPA to reduce power plant emissions of SO_2 and NO_x. The D.C. Circuit Court later remanded the CAIR to the U.S. EPA, without invalidating the entire rulemaking, so that the U.S. EPA could correct CAIR in accordance with the D.C. Circuit Court's July 11, 2008 opinion. On July 7, 2011, the U.S. EPA published the final rule, known as the CSAPR. The CSAPR requires 28 states in the eastern half of the United States to significantly improve air quality by reducing power plant emissions that cross state lines and contribute to ground-level ozone and fine particle pollution in other states.

Numerous entities challenged the CSAPR in the D.C. Circuit Court, and some requested a stay of the rule pending the Court's consideration of the matter on the merits. On December 30, 2011, the Court granted a stay of the CSAPR, and directed the U.S. EPA to continue the administration of CAIR in the interim. On August 21, 2012, a three-judge panel of the D.C. Circuit Court held that the U.S. EPA has exceeded its authority in certain material aspects of the CSAPR and vacated the rule and remanded it to the U.S. EPA for further rulemaking consistent with its decision. The Court also ordered that CAIR remain in effect pending finalization of CSAPR on remand. On January 24, 2013, the Court denied petitions for reconsideration of the ruling by the three-judge panel. In March 2013, the U.S. EPA petitioned the U.S. Supreme Court to review the D.C. Circuit Court's CSAPR decision, and Exelon has filed in support of the U.S. EPA's petition.

Under the CSAPR, Generation units were to receive allowances based on historic heat input and intrastate and limited interstate, trading of allowances was permitted. The CSAPR restricted entirely the use of pre-2012 allowances. Existing SO_2 allowances under the ARP would remain available for use under ARP. As of March 31, 2013, Generation had $51 million of emission allowances carried at the lower of weighted average cost or market.

EPA Mercury and Air Toxics Standards (MATS). The MATS rule became final on April 16, 2012. The MATS rule reduces emissions of toxic air pollutants, and finalized the new source performance standards for fossil fuel-fired electric utility steam generating units (EGUs). The MATS rule requires coal-fired EGUs to achieve high removal rates of mercury, acid gases and other metals from air emissions. To achieve these standards, coal units with no pollution control equipment installed (uncontrolled coal units) will have to make capital investments and incur higher operating expenses. It is expected that smaller, older, uncontrolled coal units will retire rather than make these investments. Coal units with existing controls that do not meet the required standards may need to upgrade existing controls or add new controls to comply. In addition, the new standards will cause oil units to achieve high removal rates of metals. Owners of oil units not currently meeting the proposed emission standards may choose to convert the units to light oils or natural gas, install control technologies or retire the units. The MATS rule requires generating stations to meet the new standards three years after the rule takes effect, April 16, 2015, with specific guidelines for an additional one or two years in limited cases. Numerous entities have challenged MATS in the D.C. Circuit Court, and Exelon was granted permission by the Court to intervene in support of the rule. A decision by the Court is expected sometime in 2013. The outcome of the appeal, and its impact on power plant operators' investment and retirement decisions, is uncertain.

Exelon, along with the other co-owners of Conemaugh Generating Station are moving forward with plans to improve the existing scrubbers and install Selective Catalytic Reduction (SCR) controls to meet the mercury removal requirements of MATS.

In addition, as of March 31, 2013, Exelon had a $700 million net investment in coal-fired plants in Georgia and Texas subject to long-term leases extending through 2028-2032. While Exelon currently estimates the value of these plants at the end of the lease term will be in excess of the recorded residual lease values, final applications of the CSAPR and MATS regulations could negatively impact the end-of-lease term values of these assets, which could result in a future impairment loss that could be material.

National Ambient Air Quality Standards (NAAQS). The U.S. EPA previously announced that it would complete a review of all NAAQS by 2014. Oral argument in the litigation (*State of Miss. v. EPA*) of the final 2008 ozone standard occurred in the D.C. Circuit Court in November 2012 and a final Court decision is expected in 2013. Concurrent with litigation of the 2008 ozone standard, the U.S. EPA continues its regular, periodic review of the ozone NAAQS and is expected to propose revisions in the fall of 2014, with preliminary indications that the U.S. EPA will likely propose a tightened standard. It is unclear at this point in time whether the U.S. EPA would be able to respond to a Court directive for the U.S. EPA to revisit the 2008 ozone NAAQS on remand on a timeframe that would be any quicker than that of the U.S. EPA's current, periodic review schedule. In December 2012, the U.S. EPA issued its final revisions to the Agency's particulate matter (PM) NAAQS. In its final rule, the U.S. EPA lowered the annual PM2.5 standard, but declined to issue a new secondary NAAQS to improve urban visibility. The U.S. EPA indicated in its final rule that by 2020 it expects

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most areas of the country will be in attainment of the new PM2.5 NAAQS based on currently expected regulations, such as the MATS regulation. It is unclear if the vacatur of the CSAPR, one of the regulations that the U.S. EPA is relying on to assist with future PM reduction, would alter the U.S. EPA's view since either CAIR or a finalized CSAPR regulation would be in effect leading up to 2020. In March 2013, a number of industry coalitions filed a joint lawsuit challenging the new PM2.5 standard. Also during early 2013, the D.C. Circuit remanded several rules for implementation of earlier PM2.5 NAAQS to the U.S. EPA for revision of certain aspects of the rules, with a requirement that the U.S. EPA re-promulgate regulations in conformance with the correct subparts of the Clean Air Act.

In addition to these NAAQS, the U.S. EPA also expects to finalize initial designations for the 2010 one-hour SO_2 standard in June 2013 and require states to submit state implementation plans (SIPs) for nonattainment areas by February 2015. In a February 2013 strategy document, the U.S. EPA establishes the direction and timeframe for state air agencies to achieve compliance with certain aspects of the NAAQS and also establishes a methodology, based on 2009-2011 air quality monitoring, for establishing nonattainment designations by June 2013. Based on its strategy document, the U.S. EPA regional offices sent "120 Day" letters to states, in February 2013, to indicate U.S. EPA's intentions with regard to designations in the states. With regard to Texas and Maryland, no nonattainment areas were identified in these letters. With regard to Illinois and Pennsylvania, several counties, or portions of counties, in each state were identified as likely to be designated nonattainment in June 2013. The U.S. EPA's strategy document also outlines a process and timeline for it to address additional designations in states' counties under separate, future action that will occur after June 2013. Nonattainment county compliance with the one-hour SO_2 standard is required by February 2018. While significant SO2 reductions will occur as a result of MATS compliance in 2015, Exelon is unable to predict the requirements of pending states' SIPs to further reduce SO_2 emissions in support of attainment of the one hour SO_2 standard.

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

On August 6, 2007, ComEd received a NOV addressed to it and Midwest Generation from the U.S. EPA, alleging, in relevant part, that ComEd and Midwest Generation violated and are continuing to violate provisions of the Clean Air Act as a result of the modification and/or operation of six electric generation stations located in northern Illinois that have been owned and operated by Midwest Generation since their purchase from ComEd in 1999. In August 2009, the United States and the State of Illinois filed a complaint against Midwest Generation with the U.S. District Court for the Northern District of Illinois initiating enforcement proceedings with respect to most of the alleged Clean Air Act violations set forth in the NOV. Neither ComEd nor Exelon was named as a defendant in this original complaint. In March 2010, the District Court granted Midwest Generation's partial motion to dismiss all but one of the claims against Midwest Generation. The District Court held that Midwest Generation cannot be liable for any alleged violations relating to construction that occurred prior to Midwest Generation's ownership of the stations. In May 2010, the government plaintiffs filed an amended complaint against Midwest Generation asserting claims substantially similar to those in the original complaint, and added ComEd and EME as defendants. The amended complaint seeks injunctive relief and civil penalties against all defendants, although not all of the claims specifically pertain to ComEd. On March 16, 2011, the District Court granted ComEd's motion to dismiss the May 2010 complaint in its entirety as it relates to ComEd. On January 3, 2012, upon leave of the District Court, the government parties appealed the dismissal of ComEd to the U.S. Circuit Court of Appeals for the Seventh Circuit. Exelon, Generation and ComEd are unable to predict the ultimate resolution of the claims alleged in the amended complaint, however, Exelon, Generation and ComEd have concluded that, in light of the March 2011 District Court decision, the likelihood of loss is remote. Therefore, no reserve has been established.

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

The Bankruptcy Court approved the rejection of a coal rail car lease under which Midwest Generation had agreed to reimburse ComEd for all obligations. The rejection left Generation as the party responsible to make remaining payments under the lease. In January 2013, Generation made the final $10 million payment due under the lease agreement which had been reserved for at December 31, 2012. As a result of the bankruptcy filing, Exelon and Generation have recorded liabilities as of March 31, 2013 of $3 million for estimated payments for asbestos personal injury claims filed pre-Petition Date. Exelon and Generation currently expect Midwest Generation or its successor will remain responsible for asbestos personal injury claims filed post-Petition Date, and as such have recorded no liability for such amounts. Requirements for Generation to ultimately satisfy such claims could have a material adverse impact on Exelon's and Generation's future results of operations.

As of the Petition Date, Generation had wholesale power transactions with Edison Mission Marketing and Trading, an affiliate of Midwest Generation not included in the bankruptcy proceeding. Generation expects these transactions to be fully settled in the normal course.

Certain environmental laws and regulations subject current and prior owners of properties or generators of hazardous substances at such properties to liability for remediation costs of environmental contamination. As a prior owner of the generating stations, ComEd (and Generation, through its agreement in the 2001 restructuring to assume ComEd's rights and obligations associated with its former generation business) could face liability (along with any other potentially responsible parties) for environmental conditions requiring remediation, with the determination of the allocation among the parties subject to many uncertain factors, including the impact of Midwest Generation's bankruptcy. Additionally, the obligations of EME and Midwest Generation to ComEd under the sale agreement, including the environmental indemnity, may be discharged in the bankruptcy proceeding. In such circumstances, ComEd (and Generation, through ComEd) may only have an unsecured claim against EME and Midwest Generation for the environmental remediation costs that would have otherwise been obligations of EME and Midwest Generation under the sale agreement. This unsecured claim may yield a fractional, or possibly no, recovery for ComEd and Generation.

ComEd and Generation continue to monitor the bankruptcy proceedings and available public information as to potential environmental exposures regarding the Midwest Generation plant sites. Midwest Generation publicly disclosed in its 2012 Form 10-K that (i) it has accrued a probable amount of approximately $9 million for estimated environmental investigation and remediation costs under CERCLA, or similar laws, for the investigation and remediation of contaminated property at four Midwest Generation plant sites, (ii) it has identified stations for which a reasonable estimate for investigation and/ or remediation cannot be made and (iii) it and the Illinois EPA entered into Compliance Commitment Agreements outlining specified environmental remediation measures and groundwater monitoring activities to be undertaken at its Crawford, Powerton, Joliet, Will County and Waukegan generating stations. At this time, however, ComEd and Generation do not have sufficient information to reasonably assess the potential likelihood or magnitude of any such exposures. Further, Midwest Generation's reorganization process will likely extend beyond one year and the outcome is uncertain, including whether the facilities will continue to operate and the identity or financial wherewithal of potential future plant owners. For these reasons, ComEd and Generation are unable to predict whether and to what extent they may ultimately be held responsible for remediation and other costs relating to the generating stations, and no liability has been recorded as of March 31, 2013. Any liability imposed on ComEd or Generation for environmental matters relating to the generating stations could have a material adverse impact on their future results of operations and cash flows.

Solid and Hazardous Waste

Cotter Corporation. The U.S. EPA has advised Cotter Corporation (Cotter), a former ComEd subsidiary, that it is potentially liable in connection with radiological contamination at a site known as the West Lake Landfill in Missouri. On February 18, 2000, ComEd sold Cotter to an unaffiliated third party. As part of the sale, ComEd agreed to indemnify Cotter for any liability arising in connection with the West Lake Landfill. In connection with Exelon's 2001 corporate restructuring, this responsibility to indemnify Cotter was transferred to Generation. On May 29, 2008, the U.S. EPA issued a Record of Decision approving the remediation option submitted by Cotter and the two other PRPs that required additional landfill cover. The current estimated cost of the anticipated landfill cover remediation for the site is approximately $42 million, which will be allocated among all PRPs. Generation has accrued what it believes to be an adequate amount to cover its anticipated share of such liability. By letter dated January 11, 2010, the U.S. EPA requested that the PRPs perform a supplemental feasibility study for a remediation alternative that would involve complete excavation of the radiological contamination. On September 30, 2011, the PRPs submitted the final supplemental feasibility study to the U.S. EPA for review. In June 2012, the U.S. EPA requested that the PRPs perform additional analysis and groundwater sampling as part of the SFS that could take up to one year to complete, and subsequently requested additional analysis sampling and modeling to be conducted in 2013. In light of these additional requests, it is unknown when the U.S EPA will propose a remedy for public comment. Thereafter the U.S. EPA will select a final remedy and enter into a Consent Decree with the PRPs to effectuate the remedy. A complete excavation remedy would be significantly more expensive than the previously selected additional cover remedy; however, Generation believes the likelihood that the U.S. EPA would require a complete excavation remedy is remote.

On August 8, 2011, Cotter was notified by the DOJ that Cotter is considered a PRP with respect to the government's clean-up costs for contamination attributable to low level radioactive residues at a former storage and reprocessing facility named Latty Avenue near St. Louis, Missouri. The Latty Avenue site is included in ComEd's indemnification responsibilities discussed above as part of the sale of Cotter. The radioactive residues had been generated initially in connection with the processing of uranium ores as part of the U.S. government's Manhattan Project. Cotter purchased the residues in 1969 for initial processing at the Latty Avenue facility for the subsequent extraction of uranium and metals. In 1976, the NRC found that the Latty Avenue site had radiation levels exceeding NRC criteria for decontamination of land areas. Latty Avenue was investigated and remediated by the United States Army Corps of Engineers pursuant to funding under the Formerly Utilized Sites Remedial Action Program. The DOJ has not yet formally advised the PRPs of the amount that it is seeking, but it is believed to be approximately $90 million. The DOJ and the PRPs agreed to toll the statute of limitations until August 2013 so that settlement discussions could proceed. Based on Exelon's preliminary review, it appears probable that Exelon has liability to Cotter under the indemnification agreement and has established an appropriate accrual for this liability.

On February 28, 2012, and April 12, 2012, two lawsuits were filed in the U.S. District Court for the Eastern District of Missouri against 15 and 14 defendants, respectively, including Exelon, Generation and ComEd (the "Exelon defendants"). The suits allege that individuals living in the North St. Louis area developed some form of cancer due to the defendants' negligent or reckless conduct in processing, transporting, storing, handling and/or disposing of radioactive materials. Plaintiffs have asserted claims for negligence, strict liability, emotional distress, medical monitoring, and violations of the Price-Anderson Act. The complaints do not contain specific damage claims. On May 30, 2012, the plaintiffs filed voluntary motions to dismiss the Exelon defendants from both lawsuits which was subsequently granted. On October 23, 2012, a third lawsuit was filed in the same court on behalf of three additional plaintiffs against Cotter and seven other defendants, but not Exelon. On April 19, 2013, a fourth lawsuit was filed in the same court on behalf of two additional plaintiffs against Cotter and seven other defendants, but not Exelon. The allegations in these latter two complaints mirror the two previously-filed lawsuits. It is reasonably possible that Exelon would be considered liable due to its indemnification responsibilities of Cotter described above. On March 27, 2013, the U.S. District Court dismissed all state common law actions brought under the initial two lawsuits; and also found that the plaintiffs had not properly brought the actions under the Price–Anderson Act. The plaintiffs have until May 10, 2013 to file amended complaints under the Price–Anderson Act. At this stage of the litigation, Exelon cannot estimate a range of loss, if any.

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

Sauer Dump. On May 30, 2012, BGE was notified by the U.S. EPA that it is considered a PRP at the Sauer Dump Superfund site in Dundalk, MD. The U.S. EPA offered BGE and three other PRPs the opportunity to conduct an environmental investigation and present cleanup recommendations at the site. The letter provided 60 days for the PRPs to decide whether or not to participate in the investigation. In addition, the U.S. EPA is seeking recovery from the PRPs of $1.7 million for past cleanup and investigation costs at the site. On March 11, 2013, BGE and three other PRP's signed an Administrative Settlement Agreement and Order on Consent with the U.S. EPA which requires the PRP's to conduct a Remedial Investigation and Feasibility Study at the site to determine what, if any, are the appropriate and recommended cleanup activities for the site. The ultimate outcome of this proceeding is uncertain. Since the U.S. EPA has not selected a cleanup remedy and the allocation of the cleanup costs among the PRPs has not been determined, an estimate of the range of BGE's reasonably possible loss, if any, cannot be determined.

Climate Change Regulation. Exelon is subject to climate change regulation or legislation at the Federal, regional and state levels. In 2007, the U.S. Supreme Court ruled that GHG emissions are pollutants subject to regulation under the new motor vehicle provisions of the Clean Air Act. Consequently, on December 7, 2009, the U.S. EPA issued an endangerment finding under Section 202 of the Clean Air Act regarding GHGs from new motor vehicles and on April 1, 2010 issued final regulations limiting GHG emissions from cars and light trucks effective on January 2, 2011. While such regulations do not specifically address stationary sources, such as a generating plant, it is the U.S. EPA's position that the regulation of GHGs under the mobile source provisions of the Clean Air Act has triggered the permitting requirements under the Prevention of Significant Deterioration (PSD) and Title V operating permit sections of the Clean Air Act for new and modified stationary sources effective January 2, 2011. Therefore, on May 13, 2010, the U.S. EPA issued final regulations (the Tailoring Rule) relating to these provisions of the Clean Air Act for major stationary sources of GHG emissions that apply to new sources that emit greater than 100,000 tons per year, on a CO_2 equivalent basis, and to modifications to existing sources that result in emissions increases greater than 75,000 tons per year on a CO_2 equivalent basis. These thresholds became effective January 2, 2011, apply for six years and will be reviewed by the U.S. EPA for future applicability thereafter. On July 2, 2012 the U.S. EPA declined to lower GHG permit thresholds in its final "Step 3" Tailoring Rule update. The U.S. EPA will review permit thresholds again in a 2015 rulemaking process. On June 26, 2012, the United States Court of Appeals for the District of Columbia, in a *per cunum* decision, dismissed industry and state petitions challenging the U.S. EPA's Tailoring Rule based on petitioners' lack of standing. Further, in the same decision, the court denied all challenges to U.S. EPA's endangerment finding, and the Agency's "Tailpipe Rule" for cars and light trucks. In August 2012, several industry parties filed petitions for an *en banc* rehearing of the Agency's GHG regulations with the D.C. Circuit court. On September 6, 2012 the Circuit Court ordered the U.S. EPA, intervening groups, and some states to reply to the industry petitions.

On April 13, 2012, the U.S. EPA published proposed regulations for NSPS for GHG emissions from new fossil fuel power plants, greater than 25 MW, that would require the plants to limit CO2 emissions to a thirty year average of less than 1,000 pounds per MWh (less than 1,800 pounds per MWh for the first ten years and less than 600 pounds per MWh thereafter). Under the PSD regulations, new and modified major stationary sources could be required to install best available control technology, to be determined on a case by case basis. Generation could be significantly affected by the regulations if it were to build new plants or modify existing plants. The U.S. EPA is also expected to establish in 2013 GHG emission regulations for existing stationary sources under Section 111(d) of the Clean Air Act.

Litigation and Regulatory Matters

Except to the extent noted below, the circumstances set forth in Note 19 of the Exelon 2012 Form 10-K describe, in all material respects, the current status of litigation matters. The following is an update to that discussion.

Asbestos Personal Injury Claims (Exelon, Generation and BGE)

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

At March 31, 2013 and December 31, 2012, Generation had reserved approximately $62 million and $63 million, respectively, in total for asbestos-related bodily injury claims. As of March 31, 2013, approximately $16 million of this amount related to 189 open claims presented to Generation, while the remaining $46 million of the reserve is for estimated future asbestos-related bodily injury claims anticipated to arise through 2050, based on actuarial assumptions and analyses, which are updated on an annual basis. On a quarterly basis, Generation monitors actual experience against the number of forecasted claims to be received and expected claim payments and evaluates whether an adjustment to the reserve is necessary. During the second quarter of 2012, Generation increased its reserve by approximately $19 million, primarily due to increased actual and projected number and severity of claims.

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

Approximately 480 individuals who were never employees of BGE or Generation have pending claims each seeking several million dollars in compensatory and punitive damages. Cross-claims and third-party claims brought by other defendants may also be filed against BGE and Generation in these actions. To date, most asbestos claims which have been resolved have been dismissed or resolved without any payment by BGE or Generation and a small minority of these cases has been resolved for amounts that were not material to BGE or Generation's financial results.

Discovery begins in these cases once they are placed on the trial docket. At present, none of the pending cases are set for trial. Given the limited discovery, BGE and Generation do not know the specific facts that are necessary to provide an estimate of the reasonably possible loss relating to these claims; as such, no accrual has been made and a range of loss is not estimable. The specific facts not known include:

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

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

Continuous Power Interruption (ComEd)

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

On August 18, 2011, ComEd sought from the ICC a determination that ComEd is not liable for damage compensation to customers in connection with the July 11, 2011 storm system that produced multiple power interruptions that in the aggregate affected more than 900,000 customers in ComEd's service territory, as well as for five other storm systems that affected ComEd's customers during June and July 2011 ("Summer 2011 Storm Docket"). The ICC is currently conducting a proceeding to assess ComEd's request. In the absence of a favorable determination from the ICC, some ComEd customers affected by the outages could seek recovery of their actual, non-consequential damages, and the local governments in the areas in which those customers are located could seek recovery of emergency and contingency expenses.

In addition, on September 29, 2011, ComEd sought from the ICC a determination that it was not liable for damage compensation related to the February 1, 2011 blizzard (February 2011 Blizzard Docket). On January 10, 2013, the ALJ issued a Proposed Order in the February 2011 Blizzard Docket, finding that a complete waiver of liability should apply for the storm. As with the Summer 2011 Storm Docket, the ALJ found that ComEd's system is designed, constructed and maintained in accordance with good utility practice.

On January 25, 2013 the ALJ issued a Proposed Order in the Summer 2011 Storm Docket. The ALJ found that a complete waiver of liability should apply for five of the six storms at issue, and found that for the July 2011 storm, 34,599 interruptions were preventable and therefore no waiver should apply. The ALJ also found that ComEd's system is designed, constructed and maintained in accordance with good utility practice, thereby rejecting a request by the Illinois Attorney General for the ICC to open an investigation.

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

The ultimate outcomes of these proceedings are uncertain, and the amount of damages, if any, which might be asserted, cannot be reasonably estimated at this time, but may be material to ComEd's results of operations and cash flows.

Securities Class Action (Exelon)

Three federal securities class action lawsuits were filed in the United States District Courts for the Southern District of New York and the District of Maryland between September 2008 and November 2008 against Constellation. The cases were filed on behalf of a proposed class of persons who acquired publicly traded securities, including the Series A Junior Subordinated Debentures (Debentures), of Constellation between January 30, 2008 and September 16, 2008, and who acquired Debentures in an offering completed in June 2008. The securities class actions generally allege that Constellation, a number of its former officers or directors, and the underwriters violated the securities laws by issuing a false and misleading registration statement and prospectus in connection with Constellation's June 27, 2008 offering of the Debentures. The securities class actions also allege that Constellation issued false or misleading statements or was aware of material undisclosed information which contradicted public statements, including in connection with its announcements of financial results for 2007, the fourth quarter of 2007, the first quarter of 2008 and the second quarter of 2008 and the filing of its first quarter 2008 Form 10-Q. The securities class actions seek, among other things, certification of the cases as class actions, compensatory damages, reasonable costs and expenses, including counsel fees, and rescission damages.

The Southern District of New York granted the defendants' motion to transfer the two securities class actions filed in Maryland to the District of Maryland, and the actions have since been transferred for coordination with the securities class action filed there. On June 18, 2009, the court appointed a lead plaintiff, who filed a consolidated amended complaint on September 17, 2009. On November 17, 2009, the defendants moved to dismiss the consolidated amended complaint in its entirety. On August 13, 2010, the District Court of Maryland issued a ruling on the motion to dismiss, holding that the plaintiffs failed to state a claim with respect to the claims of the common shareholders under the Securities Exchange Act of 1934 and limiting the suit to those persons who purchased Debentures in the June 2008 offering. In August 2011, plaintiffs requested permission from the court to file a third amended complaint in an effort to attempt to revive the claims of the common shareholders. Constellation filed an objection to the plaintiffs' request for permission to file a third amended complaint and, on March 28, 2012, the District Court of Maryland denied the plaintiffs' request for permission to revive the claims of the common shareholders. On March 22, 2013, the lead plaintiff submitted a motion seeking the District Court of Maryland's preliminary approval of a proposed class action settlement resolving the Debenture holder claims for approximately $4 million and dismissal of the complaint. Upon preliminary approval of the settlement by the Court, notice will be provided to the Debenture holders of the settlement terms and final court approval will be required for the settlement to become effective.

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

The Registrants are involved in various other litigation matters that are being defended and handled in the ordinary course of business. The assessment of whether a loss is probable or a reasonable possibility, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. The Registrants maintain accruals for losses that are probable of being incurred and subject to reasonable estimation. Management is sometimes unable to estimate an amount or range of reasonably possible loss, particularly where (1) the damages sought are indeterminate, (2) the proceedings are in the early stages, or (3) the matters involve novel or unsettled legal theories. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution of such matters, including a possible eventual loss.

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

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

See Note 11 — Income Taxes for information regarding the Registrants' income tax refund claims and certain tax positions, including the 1999 sale of fossil generating assets.

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

Supplemental Statement of Operations Information

The following tables provide additional information about the Registrants' Consolidated Statements of Operations for the three months ended March 31, 2013 and 2012:

Three Months Ended March 31, 2013	Exelon	Generation	ComEd	PECO	BGE
Other, Net					
Decommissioning-related activities:					
Net realized income on decommissioning trust funds(a)					
Regulatory Agreement Units	$ 36	$ 36	$ —	$ —	$ —
Non-Regulatory Agreement Units	14	14	—	—	—
Net unrealized gains on decommissioning trust funds					
Regulatory Agreement Units	195	195	—	—	—
Non-Regulatory Agreement Units	64	64	—	—	—
Net unrealized gains on pledged assets					
Zion Station decommissioning	2	2	—	—	—
Regulatory offset to decommissioning trust fund-related activities(b)	(190)	(190)	—	—	—
Total decommissioning-related activities	121	121	—	—	—
Investment income (expense)	3	(2)	—	—	2(c)
Long-term lease income	8	—	—	—	—
Interest income related to uncertain income tax positions	25	5	—	—	—
AFUDC — Equity	6	—	3	1	2
Other	9	4	2	2	1
Other, net	$ 172	$ 128	$ 5	$ 3	$ 5

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

Three Months Ended March 31, 2012	Exelon	Generation	ComEd	PECO	BGE
Other, Net					
Decommissioning-related activities:					
Net realized income on decommissioning trust funds(a)					
Regulatory Agreement Units	$ 60	$ 60	$ —	$ —	$ —
Non-Regulatory Agreement Units	48	48	—	—	—
Net unrealized gains on decommissioning trust funds					
Regulatory Agreement Units	247	247	—	—	—
Non-Regulatory Agreement Units	65	65	—	—	—
Net unrealized gains on pledged assets					
Zion Station decommissioning	35	35	—	—	—
Regulatory offset to decommissioning trust fund-related activities(b)	(277)	(277)	—	—	—
Total decommissioning-related activities	178	178	—	—	—
Investment income	4	—	1	1	3(c)
Long-term lease income	7	—	—	—	—
AFUDC — Equity	3	—	1	1	3
Other	2	—	2	—	—
Other, net	$ 194	$ 178	$ 4	$ 2	$ 6

(a) Includes investment income and realized gains and losses on sales of investments of the trust funds.

(b) Includes the elimination of NDT fund-related activity for the Regulatory Agreement Units, including the elimination of net income taxes related to all NDT fund activity for those units. See Note 13 of the Exelon 2012 Form 10-K for additional information regarding the accounting for nuclear decommissioning.

(c) Relates to the cash return on BGE's rate stabilization deferral. See Note 5 — Regulatory Matters for additional information regarding the rate stabilization deferral.

Supplemental Cash Flow Information

The following tables provide additional information regarding the Registrants' Consolidated Statements of Cash Flows for the three months ended March 31, 2013 and 2012:

Three Months Ended March 31, 2013	Exelon	Generation	ComEd	PECO	BGE
Depreciation, amortization, accretion and depletion					
Property, plant and equipment	$ 471	$ 203	$ 137	$ 55	$ 64
Regulatory assets	61	—	30	2	29
Amortization of intangible assets, net	11	11	—	—	—
Amortization of energy contract assets and liabilities(a)	176	176	—	—	—
Nuclear fuel(a)	230	230	—	—	—
ARO accretion(b)	68	68	—	—	—
Total depreciation, amortization, accretion and depletion	$1,017	$ 688	$ 167	$ 57	$ 93

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

Three Months Ended March 31, 2012	Exelon	Generation	ComEd	PECO	BGE
Depreciation, amortization, accretion and depletion					
Property, plant and equipment	$ 354	$ 150	$ 131	$ 51	$ 61
Regulatory assets	25	—	18	2	18
Amortization of intangible assets, net	3	3	—	—	—
Amortization of energy contract assets and liabilities(a)	131	131	—	—	—
Nuclear fuel(a)	207	207	—	—	—
ARO accretion(b)	56	56	—	—	—
Total depreciation, amortization, accretion and depletion	$ 776	$ 547	$ 149	$ 53	$ 79

(a) Included in revenues or fuel expense on the Registrants' Consolidated Statements of Operations and Comprehensive Income.
(b) Included in operating and maintenance expense on the Registrants' Consolidated Statements of Operations.

Three Months Ended March 31, 2013	Exelon	Generation	ComEd	PECO	BGE
Other non-cash operating activities:					
Pension and non-pension postretirement benefit costs	$ 205	$ 87	$ 77	$ 11	$ 14
Loss in equity method investments	9	9	—	—	—
Provision for uncollectible accounts	45	7	9	25	4
Stock-based compensation costs	39	4	1	1	1
Other decommissioning-related activity(a)	(64)	(64)	—	—	—
Energy-related options(b)	21	21	—	—	—
Amortization of regulatory asset related to debt costs	4	—	3	1	—
Amortization of rate stabilization deferral	30	—	—	—	30
Amortization of debt fair value adjustment	(9)	(9)	—	—	—
Discrete impacts from Energy Infrastructure Modernization Act (EIMA)(d)	(49)	—	(49)	—	—
Amortization of debt costs	5	3	1	1	—
Merger integration costs(f)	(6)	—	—	—	(6)
Other	1	8	—	—	(1)
Total other non-cash operating activities	$ 231	$ 66	$ 42	$ 39	$ 42
Changes in other assets and liabilities:					
Under/over-recovered energy and transmission costs	$ 29	$ —	$ (18)	$ 22	$ 16
Other regulatory assets and liabilities	91	—	(14)	13	(53)
Other current assets	(169)	(131)	—	(75)(f)	73
Other noncurrent assets and liabilities	282	(28)	263	2	(2)
Total changes in other assets and liabilities	$ 233	$ (159)	$ 231	$ (38)	$ 34
Non-cash investing and financing activities:					
Consolidated VIE dividend to non-controlling interest	$ 63	$ 63	$ —	$ —	$ —
Indemnification of like-kind exchange position(e)	—	—	172	—	—
Total non-cash investing and financing activities:	$ 63	$ 63	$ 172	$ —	$ —

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

Three Months Ended March 31, 2012	Exelon	Generation	ComEd	PECO	BGE
Other non-cash operating activities:					
Pension and non-pension postretirement benefit costs	$ 181	$ 81	$ 69	$ 13	$ 16
Loss in equity method investments	22	22	—	—	—
Provision for uncollectible accounts	40	(9)	22	24	8
Stock-based compensation costs	39	—	—	—	—
Other decommissioning-related activity(a)	(71)	(71)	—	—	—
Energy-related options(b)	28	28	—	—	—
Amortization of regulatory asset related to debt costs	6	—	4	1	1
Amortization of rate stabilization deferral	3	—	—	—	13
Merger-related commitments(c)	331	35	—	—	141
Discrete impacts from Energy Infrastructure Modernization Act EIMA(d)	(38)	—	(38)	—	—
Other	(11)	4	3	2	—
Total other non-cash operating activities	$ 530	$ 90	$ 60	$ 40	$179
Changes in other assets and liabilities:					
Under/over-recovered energy and transmission costs	$ (25)	$ —	$ (38)	$ 13	$ (10)
Other regulatory assets and liabilities	(97)	—	(16)	3	(39)
Other current assets	(18)	(122)	1	(134)(g)	31
Other noncurrent assets and liabilities	18	42	(19)	8	7
Total changes in other assets and liabilities	$ (122)	$ (80)	$ (72)	$(110)	$ (11)
Non-cash investing and financing activities:					
Merger with Constellation, common stock issued	$7,365	$ 5,272	$ —	$ —	$ —
Total non-cash investing and financing activities:	$7,365	$ 5,272	$ —	$ —	$ —

(a) Includes the elimination of NDT fund-related activity for the Regulatory Agreement Units, including the elimination of operating revenues, ARO accretion, ARC amortization, investment income and income taxes related to all NDT fund activity for these units. See Note 13 of the Exelon 2012 Form 10-K for additional information regarding the accounting for nuclear decommissioning.
(b) Includes option premiums reclassified to realized at the settlement of the underlying contracts and recorded to results of operations.
(c) See Note 4 — Mergers and Acquisitions for more information on merger-related commitments.
(d) Reflects the change in distribution rates pursuant to EIMA, which allows for the recovery of costs by a utility through a pre-established performance-based formula rate tariff. See Note 5 — Regulatory Matters for more information.
(e) See Note 11 — Income Taxes for discussion of the like-kind exchange position.
(f) Relates to integration costs to achieve distribution synergies related to the merger transaction. See Note 5 — Regulatory Matters for more information.
(g) Relates primarily to prepaid utility taxes.

DOE Smart Grid Investment Grant (Exelon, PECO and BGE). For the three months ended March 31, 2013, Exelon, PECO and BGE have included in the capital expenditures line item under investing activities of the cash flow statement capital expenditures of $21 million, $6 million and $15 million, respectively, and reimbursements of $32 million, $12 million and $20 million, respectively, related to PECO’s and BGE’s DOE SGIG programs. For the three months ended March 31, 2012, Exelon, PECO and BGE have included in the capital expenditures line item under investing activities of the cash flow statement capital expenditures of $26 million, $20 million and $6 million, respectively, and reimbursements of $35 million, $21 million and $14 million, respectively, related to PECO’s and BGE’s DOE SGIG programs. See Note 5 - Regulatory Matters for additional information regarding the DOE SGIG.

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

Supplemental Balance Sheet Information

The following tables provide additional information about assets and liabilities of the Registrants as of March 31, 2013 and December 31, 2012.

March 31, 2013	Exelon	Generation	ComEd	PECO	BGE
Property, plant and equipment:					
Accumulated depreciation and amortization	$12,579(a)	$ 6,347(a)	$2,969	$2,840	$2,627
Accounts receivable:					
Allowance for uncollectible accounts	320	84	78	122	36

December 31, 2012	Exelon	Generation	ComEd	PECO	BGE
Property, plant and equipment:					
Accumulated depreciation and amortization	$12,184(b)	$ 6,014(b)	$2,998	$2,797	$2,595
Accounts receivable:					
Allowance for uncollectible accounts	293	84	70	99	40

(a) Includes accumulated amortization of nuclear fuel in the reactor core of $2,221 million.
(b) Includes accumulated amortization of nuclear fuel in the reactor core of $2,078 million.

PECO Installment Plan Receivables (Exelon and PECO)

PECO enters into payment agreements with certain delinquent customers, primarily residential, seeking to restore their service, as required by the PAPUC. Customers with past due balances that meet certain income criteria are provided the option to enter into an installment payment plan, some of which have terms greater than one year, to repay past due balances in addition to paying for their ongoing service on a current basis. The receivable balance for these payment agreement receivables is recorded in accounts receivable for the current portion and other deferred debits and other assets for the noncurrent portion. The net receivable balance for installment plans with terms greater than one year was $18 million as of March 31, 2013 and December 31, 2012. The allowance for uncollectible accounts reserve methodology and assessment of the credit quality of the installment plan receivables are consistent with the customer accounts receivable methodology discussed in Note 1 of the Exelon 2012 Form 10-K. The allowance for uncollectible accounts balance associated with these receivables at March 31, 2013 of $14 million consists of $1 million, $4 million and $9 million for low risk, medium risk and high risk segments, respectively. The allowance for uncollectible accounts balance at December 31, 2012 of $15 million consists of $1 million, $3 million and $11 million for low risk, medium risk and high risk segments, respectively. The balance of the payment agreement is billed to the customer in equal monthly installments over the term of the agreement. Installment receivables outstanding as of March 31, 2013 and December 31, 2012 include balances not yet presented on the customer bill, accounts currently billed and an immaterial amount of past due receivables. When a customer defaults on its payment agreement, the terms of which are defined by plan type, the entire balance of the agreement becomes due and the balance is reclassified to current customer accounts receivable and reserved for in accordance with the methodology discussed in Note 1 of the Exelon 2012 Form 10-K.

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

Exelon has nine reportable segments, ComEd, PECO, BGE and Generation’s six power marketing reportable segments consisting of the Mid-Atlantic, Midwest, New England, New York, ERCOT and all other regions not considered individually significant referred to collectively as “Other Regions”; including the South, West and Canada. Generation’s expanded number of reportable segments is the result of the acquisition of Constellation on March 12, 2012. ComEd, PECO and BGE each represent a single reportable segment; as such, no separate segment information is provided for these Registrants. Exelon evaluates the performance of ComEd, PECO and BGE based on net income.

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

- Mid-Atlantic represents operations in the eastern half of PJM, which includes Pennsylvania, New Jersey, Maryland, Virginia, West Virginia, Delaware, the District of Columbia and parts of North Carolina.
- Midwest represents operations in the western half of PJM, which includes portions of Illinois, Indiana, Ohio, Michigan, Kentucky and Tennessee, and the entire United States footprint of MISO, which covers all or most of North Dakota, South Dakota, Nebraska, Minnesota, Iowa, Wisconsin, the remaining parts of Illinois, Indiana, Michigan and Ohio not covered by PJM, and parts of Montana, Missouri and Kentucky.
- New England represents the operations within ISO-NE covering the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont.
- New York represents operations within ISO-NY, which covers the state of New York in its entirety.
- ERCOT represents operations within Electric Reliability Council of Texas, covering most of the state of Texas.
- Other Regions not considered individually significant:
    - South represents operations in the FRCC and the remaining portions of the SERC not included within MISO or PJM, which includes all or most of Florida, Arkansas, Louisiana, Mississippi, Alabama, Georgia, Tennessee, North Carolina, South Carolina and parts of Missouri, Kentucky and Texas. Generation's South region also includes operations in the SPP, covering Kansas, Oklahoma, most of Nebraska and parts of New Mexico, Texas, Louisiana, Missouri, Mississippi and Arkansas.
    - West represents operations in the WECC, which includes California ISO, and covers the states of California, Oregon, Washington, Arizona, Nevada, Utah, Idaho, Colorado, and parts of New Mexico, Wyoming and South Dakota.
    - Canada represents operations across the entire country of Canada and includes the AESO, OIESO and the Canadian portion of MISO.

Exelon and Generation evaluate the performance of Generation's power marketing activities based on revenue net of purchased power and fuel expense. Generation believes that revenue net of purchased power and fuel expense is a useful measurement of operational performance. Revenue net of purchased power and fuel expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report. Generation's operating revenues include all sales to third parties and affiliated sales to ComEd, PECO and BGE. Purchased power costs include all costs associated with the procurement and supply of electricity including capacity, energy and ancillary services. Fuel expense includes the fuel costs for Generation's own generation and fuel costs associated with tolling agreements. Generation's other business activities, including retail and wholesale gas, upstream natural gas, proprietary trading, energy efficiency and demand response, the design, construction, and operation of renewable energy, heating, cooling, and cogeneration facilities, and home improvements, sales of electric and gas appliances, servicing of heating, air conditioning, plumbing, electrical, and indoor quality systems, are not allocated to regions. Further, Generation's compensation under the reliability-must-run rate schedule, results of operations from the Brandon Shores, Wagner, and C.P. Crane Maryland generating stations, and other miscellaneous revenues, mark-to-market impact of economic hedging activities, and amortization of certain intangible assets relating to commodity contracts recorded at fair value as a result of the merger are also not allocated to a region.

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

An analysis and reconciliation of the Registrants' reportable segment information to the respective information in the consolidated financial statements for the three and three months ended March 31, 2013 and 2012 is as follows:

	Generation(a)	ComEd	PECO	BGE(b)	Other(c)	Intersegment Eliminations	Exelon
Total revenues(d):							
2013	$ 3,533	$ 1,160	$ 895	$ 880	$ 318	$ (704)	$ 6,082
2012	2,743	1,388	875	52	351	(719)	4,690
Intersegment revenues(e):							
2013	$ 381	$ 1	$ —	$ 4	$ 318	$ (704)	$ —
2012	370	1	1	1	346	(719)	—
Net income (loss):							
2013	$ (17)	$ (81)	$ 122	$ 80	$ (103)	$ —	$ 1
2012	166	87	97	(65)	(85)	—	200
Total assets:							
March 31, 2013	$ 39,991	$23,256	$9,491	$7,639	$10,139	$ (12,273)	$78,243
December 31, 2012	40,681	22,905	9,353	7,506	10,432	(12,316)	78,561

(a) Generation includes the six power marketing reportable segments shown below: Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Regions. Intersegment revenues for Generation for the three months ended March 31, 2013 include revenue from sales to PECO of $141 million and sales to BGE of $113 million in the Mid-Atlantic region, and sales to ComEd of $145 million in the Midwest region, net of $(17) million related to the unrealized mark-to-market losses related to the ComEd swap, which eliminate upon consolidation. For the three months ended March 31, 2012 intersegment revenues for Generation include revenue from sales to PECO of $111 million and sales to BGE of $19 million in the Mid-Atlantic region, and sales to ComEd of $247 million in the Midwest region, net of $11 million related to the unrealized mark-to-market losses related to the ComEd swap, which eliminate upon consolidation.

(b) 2012 amounts represent activity recorded at BGE from March 12, 2012, the closing date of the merger, through March 31, 2012.

(c) Other primarily includes Exelon's corporate operations, shared service entities and other financing and investment activities.

(d) For the three months ended March 31, 2013 and 2012, utility taxes of $21 million and $13 million, respectively, are included in revenues and expenses for Generation. For the three months ended March 31, 2013 and 2012, utility taxes of $60 million and $61 million, respectively, are included in revenues and expenses for ComEd. For the three months ended March 31, 2013 and 2012, utility taxes of $34 million and $34 million, respectively, are included in revenues and expenses for PECO. For the three months ended March 31, 2013 and for the period March 12, 2012 through March 31, 2012, utility taxes of $22 million and $3 million, respectively, are included in revenues and expenses for BGE.

(e) The intersegment profit associated with Generation's sale of AECs to PECO is not eliminated in consolidation due to the recognition of intersegment profit in accordance with regulatory accounting guidance. See Note 3 — Regulatory Matters of the Exelon 2012 Form 10-K for additional information on AECs. For Exelon, these amounts are included in operating revenues in the Consolidated Statements of Operations.

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

Generation total revenues:

	2013			2012		
	Revenues from external customers(a)	Intersegment revenues	Total Revenues	Revenues from external customers(a)	Intersegment revenues	Total Revenues
Mid-Atlantic	$ 1,331	$ (8)	$ 1,323	$ 970	$ (4)	$ 966
Midwest	1,181	7	1,188	1,215	4	1,219
New England	391	12	403	91	2	93
New York	175	(6)	169	45	(2)	43
ERCOT	293	—	293	128	—	128
Other Regions(b)	183	42	225	75	4	79
Total Revenues for Reportable Segments	$ 3,554	$ 47	$ 3,601	$ 2,524	$ 4	$ 2,528
Other(c)	(21)	(47)	(68)	219	(4)	215
Total Generation Consolidated Operating Revenues	$ 3,533	$ —	$ 3,533	$ 2,743	$ —	$ 2,743

(a) Includes all electric sales to third parties and affiliated sales to ComEd, PECO and BGE.
(b) Other regions include the South, West and Canada, which are not considered individually significant.
(c) Other represents activities not allocated to a region. See text above for a description of included activities. Also includes amortization of intangible assets related to commodity contracts recorded at fair value at the merger date of $174 million and $122 million, for the three months ended March 31, 2013 and 2012, respectively.

Generation total revenues net of purchased power and fuel expense:

	2013			2012		
	RNF from external customers(a)	Intersegment RNF	Total RNF	RNF from external customers(a)	Intersegment RNF	Total RNF
Mid-Atlantic	$ 852	$ (8)	$ 844	$ 774	$ (4)	$ 770
Midwest	710	7	717	813	4	817
New England	18	12	30	37	2	39
New York	(16)	(6)	(22)	10	(2)	8
ERCOT	112	(11)	101	34	—	34
Other Regions(b)	10	35	45	10	4	14
Total Revenues net of purchased power and fuel expense for Reportable Segments	$ 1,686	$ 29	$1,715	$ 1,678	$ 4	$1,682
Other(c)	(322)	(29)	(351)	21	(4)	17
Total Generation Revenues net of purchased power and fuel expense	$ 1,364	$ —	$1,364	$ 1,699	$ —	$1,699

(a) Includes purchases and sales from third parties and affiliated sales to ComEd, PECO and BGE.
(b) Other regions includes the South, West and Canada, which are not considered individually significant.
(c) Other represents activities not allocated to a region. See text above for a description of included activities. Also includes amortization of intangible assets related to commodity contracts recorded at fair value at the merger date of $174 million and $122 million, for the three months ended March 31, 2013 and 2012, respectively.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

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

EXELON CORPORATION

General

Exelon, a utility services holding company, operates through the following principal subsidiaries:

- *Generation*, whose integrated business consists of owned, contracted and investments in electric generating facilities managed through customer supply of electric and natural gas products and services, including renewable energy products, risk management services and natural gas exploration and production activities.
- *ComEd*, whose business consists of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services in northern Illinois, including the City of Chicago.
- *PECO,* whose business consists of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services in southeastern Pennsylvania, including the City of Philadelphia, and the purchase and regulated retail sale of natural gas and the provision of distribution services in the Pennsylvania counties surrounding the City of Philadelphia.
- *BGE,* whose business consists of the purchase and regulated retail sale of electricity and 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.

Exelon has nine reportable segments consisting of Generation's six power marketing reportable segments (Mid-Atlantic, Midwest, New England, New York, ERCOT and other regions in Generation), ComEd, PECO and BGE. See Note 19 of the Combined Notes to Consolidated Financial Statements for additional information regarding Exelon's reportable segments.

Through its business services subsidiary BSC, Exelon provides its operating subsidiaries with a variety of support services at cost. The costs of these services are directly charged or allocated to the applicable operating segments. Additionally, the results of Exelon's corporate operations include costs for corporate governance and interest costs and income from various investment and financing activities.

Exelon's consolidated financial information includes the results of its four separate operating subsidiary registrants, Generation, ComEd, PECO and BGE, which, along with Exelon, are collectively referred to as the Registrants. The following combined Management's Discussion and Analysis of Financial Condition and Results of Operations is separately filed by Exelon, Generation, ComEd, PECO and BGE. However, none of the Registrants makes any representation as to information related solely to any of the other Registrants.

Executive Overview

Financial Results. The following consolidated financial results reflect the results of Exelon for the three months ended March 31, 2013 compared to the same period in 2012. The 2012 financial results only include the operations of Constellation and BGE from the date of the merger with Constellation (the Merger), March 12, 2012, through March 31, 2012. All amounts presented below are before the impact of income taxes, except as noted.

	Three Months Ended March 31, 2013 Generation	ComEd	PECO	BGE	Other	Exelon	2012 Exelon	Favorable (Unfavorable) Variance
Operating revenues	$ 3,533	$1,160	$895	$880	$(386)	$6,082	$4,690	$ 1,392
Purchased power and fuel	2,169	382	406	426	(402)	2,981	1,765	(1,216)
Revenue net of purchased power and fuel(a)	1,364	778	489	454	16	3,101	2,925	176
Other operating expenses								
Operating and maintenance	1,112	328	188	143	(7)	1,764	1,968	204
Depreciation and amortization	214	167	57	93	12	543	382	(161)
Taxes other than income	93	74	41	55	14	277	194	(83)
Total other operating expenses	1,419	569	286	291	19	2,584	2,544	(40)
Equity in losses of unconsolidated affiliates	(9)	—	—	—	—	(9)	(22)	13
Operating income	(64)	209	203	163	(3)	508	359	149
Other income and (deductions)								
Interest expense, net	(82)	(353)	(29)	(33)	(126)	(623)	(195)	(428)
Other, net	128	5	3	5	31	172	194	(22)
Total other income and (deductions)	46	(348)	(26)	(28)	(95)	(451)	(1)	(450)
Income (loss) before income taxes	(18)	(139)	177	135	(98)	57	358	(301)
Income taxes	(1)	(58)	55	55	5	56	158	102
Net income (loss)	(17)	(81)	122	80	(103)	1	200	(199)
Net (loss) income attributable to noncontrolling interests, preferred security dividends and preference stock dividends	1	—	1	3	—	5	—	(5)
Net income (loss) on common stock	$ (18)	$ (81)	$121	$ 77	$(103)	$ (4)	$ 200	$ (204)

(a) The Registrants' evaluate operating performance using the measure of revenue net of purchased power and fuel expense. The Registrants' believe that revenue net of purchased power and fuel expense is a useful measurement because it provides information that can be used to evaluate its operational performance. Revenue net of purchased power and fuel expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

Exelon's net income (loss) on common stock was $(4) million for the three months ended March 31, 2013 as compared to net income of $200 million for the three months ended March 31, 2012, and diluted earnings per average common share were $(0.01) for the three months ended March 31, 2013 as compared to $0.28 for the three months ended March 31, 2012.

Operating revenue net of purchased power and fuel expense, which is a non-GAAP measure discussed below, increased by $176 million primarily due to the addition of BGE's and Constellation's financial results for the full quarter in 2013. BGE's operating revenue net of purchased power and fuel expense was $454 million for the three months ended March 31, 2013, compared to a loss of $(16) million from March 12, 2012 through March 31, 2012. Generation's operating revenue net of purchased power and fuel expense decreased by $335 million primarily due to mark-to-market losses of $403 million in 2013 from economic hedging activities, net of intercompany eliminations, compared to $60 million in mark-to-market gains in 2012. The year-over-year results for Generation are negatively impacted by an increase in amortization expense of $52 million for the acquired energy contracts, net, recorded at fair value at the merger date. Also, revenue net of purchased power and fuel expenses decreased by $100 million in the Midwest primarily due to lower capacity revenues and increased nuclear fuels costs. Offsetting these unfavorable impacts was a net increase of $133 million in revenue net of purchased power and fuel expense in all other regions primarily due to the addition of Constellation's operations for the full first quarter in 2013. Generation's results were also favorably affected by $147 million of other activities, including proprietary trading, retail gas, energy efficiency, energy management and demand response, upstream natural gas and the design and construction of customer sited solar facilities.

ComEd's operating revenues net of purchased power and fuel expense increased by $10 million primarily due to favorable weather conditions and higher electric distribution revenues, partially offset by decreased cost recovery for uncollectible accounts. PECO's operating revenues net of purchased power and fuel expense increased by $25 million primarily due to favorable weather conditions, partially offset by lower realized prices.

Operating and maintenance expense decreased by $204 million primarily due to certain prior year transactions associated with the Merger. Exelon incurred $216 million in costs as part of the Maryland order approving the Merger and costs of $195 million associated with a settlement with the FERC in March, 2012. Also, Constellation merger and integration costs decreased by $123 million. Decreased operating and maintenance expense was partially offset by increased labor, other benefits, contracting and materials costs of $270 million and increased pension and non-pension postretirement benefit expenses of $16 million, primarily due to the addition of BGE and Constellation for the full quarter in 2013.

Depreciation and amortization expense increased by $161 million primarily due to higher plant balances resulting from the addition of BGE's and Constellation's plant balances for the full quarter in 2013, as well as ongoing capital expenditures across the operating companies.

Equity in losses of unconsolidated affiliates decreased by $13 million primarily due to net income generated from Exelon's equity investment in CENG in 2013 compared to the loss recorded by CENG from March 12, 2012 through March 31, 2012. The loss recorded for this period in 2012 was due to planned nuclear fueling outage days. Partially offsetting this improvement in CENG's earnings, Generation's results were also affected by increased amortization of the basis difference in CENG recorded at fair value at the merger.

Interest expense increased by $428 million due to an increase in interest expense at ComEd related to the remeasurement of Exelon's like-kind exchange tax position in the first quarter of 2013, an increase in debt obligations as a result of the Merger and an increase in debt issued at Generation in June 2012.

Exelon's effective income tax rates for the three months ended March 31, 2013 and 2012 were 98.2% and 44.1%, respectively. See Note 11 of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

For further detail regarding the financial results for the three months ended March 31, 2013, including explanation of the non-GAAP measure revenue net of purchased power and fuel expense, see the discussions of Results of Operations by Segment below.

Adjusted (non-GAAP) Operating Earnings. Exelon's adjusted (non-GAAP) operating earnings for the three months ended March 31, 2013 were $ 602 million, or $ 0.70 per diluted share, compared with adjusted (non-GAAP) operating earnings of $ 603 million, or $ 0.85 per diluted share, for the same period in 2012. In addition to net income, Exelon evaluates its operating performance using the measure of adjusted (non-GAAP) operating earnings because management believes it represents earnings directly related to the ongoing operations of the business. Adjusted (non-GAAP) operating earnings exclude certain costs, expenses, gains and losses and other specified items. This information is intended to enhance an investor's overall understanding of year-to-year operating results and provide an indication of Exelon's baseline operating performance excluding items that are considered by management to be not directly related to the ongoing operations of the business. In addition, this information is among the primary indicators management uses as a basis for evaluating performance, allocating resources, setting incentive compensation targets and planning and forecasting of future periods. Adjusted (non-GAAP) operating earnings is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

The following table provides a reconciliation between net income as determined in accordance with GAAP and adjusted (non-GAAP) operating earnings for the three months ended March 31, 2013 as compared to the same period in 2012:

	Three Months Ended March 31,			
	2013		2012	
(All amounts after tax: in millions, except per share amounts)		Earnings per Diluted Share		Earnings per Diluted Share
Net Income (Loss) on Common Stock	$ (4)	$ (0.01)	$ 200	$ 0.28
Mark-to-Market Impact of Economic Hedging Activities(a)	235	0.27	(43)	(0.06)
Unrealized Gains Related to NDT Fund Investments(b)	(35)	(0.04)	(36)	(0.05)
Plant Retirements & Divestitures(c)	(13)	(0.02)	6	0.01
Constellation Merger and Integration Costs(d)	27	0.03	113	0.16
Maryland Commitments(e)	—	—	227	0.32
Amortization of Commodity Contract Intangibles(f)	117	0.14	78	0.11
FERC Settlement(g)	—	—	172	0.25
Non-Cash Remeasurement of Deferred Income Taxes(h)	—	—	(117)	(0.17)
Other Acquisition Costs(i)	—	—	3	—
Amortization of the Fair Value of Certain Debt(j)	(3)	—	—	—
Remeasurement of Like-Kind Exchange Tax Position(k)	265	0.31		
Nuclear Uprate Project Cancellation(l)	13	0.02		
Adjusted (non-GAAP) Operating Earnings	$602	$ 0.70	$ 603	$ 0.85

(a) Reflects the impact of losses (gains) for the three months ended March 31, 2013 and 2012, respectively, on Generation's economic hedging activities (net of taxes of $150 million and $(28) million, respectively). See Note 9 of the Combined Notes to Consolidated Financial Statements for additional detail related to Generation's hedging activities.

(b) Reflects the impact of unrealized gains for the three months ended March 31, 2013 and 2012 on Generation's NDT fund investments for Non-Regulatory Agreement Units (net of taxes of $(68) million and $(83) million, respectively). See Note 12 of the Combined Notes to Consolidated Financial Statements for additional detail related to Generation's NDT fund investments.

(c) Reflects the impacts associated with the sale or retirement of generating stations for the three months ended March 31, 2013 and 2012 (net of taxes of $5 million and $3 million, respectively). See "Results of Operations — Generation" for additional detail related to the generating station retirements.

(d) Reflects certain costs incurred for the three months ended March 31, 2013 and 2012 (net of taxes of $(6) million and $31 million, respectively) associated with the Constellation merger including transaction costs, employee-related expenses (e.g. severance, retirement, relocation and retention bonuses) integration initiatives and certain pre-acquisition contingencies, partially offset in 2013 by a one-time benefit pursuant to the BGE 2012 electric and gas distribution rate case order for the recovery of previously incurred integration costs. See Note 4 of the Combined Notes to Consolidated Financial Statements for additional information.

(e) Reflects costs incurred for the three months ended March 31, 2012 associated with the Constellation merger (net of taxes of $101 million) as part of the Maryland order approving the merger transaction. See Note 4 of the Combined Notes to Consolidated Financial Statements for additional information.

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(f) Reflects the non-cash impact for the three months ended March 31, 2013 and 2012 (net of taxes of $75 million and $51 million, respectively) of the amortization of intangible assets, net, related to commodity contracts recorded at fair value at the merger date. See Note 4 of the Combined Notes to Consolidated Financial Statements for additional information.

(g) Reflects costs incurred for the three months ended March 31, 2012 (net of taxes of $23 million) as part of a settlement with the FERC to resolve a dispute related to Constellation's pre-merger hedging and risk management transactions. See Note 17 of the Combined Notes to Consolidated Financial Statements for additional information.

(h) Reflects the non-cash impacts of the remeasurement of state deferred income taxes as a result of the merger. See Note 11 of the Combined Notes to Consolidated Financial Statements for additional information.

(i) Reflects certain costs incurred for the three months ended March 31, 2012 (net of taxes of $2 million) associated with various acquisitions.

(j) Reflects the non-cash amortization of certain debt for the three months ended March 31, 2013 (net of taxes of $2 million) recorded at fair value at the Constellation merger date expected to be retired in 2013. See Note 4 of the Combined Notes to Consolidated Financial Statements for additional information.

(k) Reflects a non-cash charge to earnings for the three months ended March 31, 2013 (net of taxes of $104 million) resulting from the first quarter 2013 remeasurement of a like-kind exchange tax position taken on ComEd's 1999 sale of fossil generating assets. See Note 11 of the Combined Notes to Consolidated Financial Statements for additional information.

(l) Reflects a 2013 charge to earnings for the three months ended March 31, 2013 (net of taxes of $8 million) related to Generation's cancellation of previously capitalized nuclear uprate projects.

As discussed above, Exelon has incurred and will continue to incur costs associated with the Constellation merger including, meeting the various commitments set forth by regulators and agreed-upon with other interested parties as part of the merger approval process, and integrating the former Constellation businesses into Exelon.

For the three months ended March 31, 2013 and 2012, expense has been recognized for costs incurred to achieve the merger as follows:

	Pre-tax Expense Three Months Ended March 31, 2013				
Merger and Integration Costs:	**Generation(a)**	**ComEd**	**PECO**	**BGE(a)**	**Exelon(a)**
Employee-Related(b)	6	—	1	—	7
Other(c)	17	—	2	(6)(d)	14
Total	$ 23	$ —	$ 3	$ (6)	$ 21

	Pre-tax Expense Three Months Ended March 31, 2012				
Merger and Integration Costs:	**Generation(a)**	**ComEd**	**PECO**	**BGE(a)**	**Exelon(a)**
Transaction(e)	$ —	$ —	$ —	$ —	$ 50
Maryland Commitments	35	—	—	139	328
Employee-Related(b)	47	—	5	—	58
Other(c)	28	2	2	1	36
Total	$ 110	$ 2	$ 7	$ 140	$ 472

(a) For Exelon, Generation and BGE, includes the operations of the acquired businesses for the three months ended March 31, 2013 and from the date of the merger, March 12, 2012, through March 31, 2012.

(b) Costs primarily for employee severance, pension and OPEB expense and retention bonuses. ComEd established regulatory assets of $1 million and $12 million during the three months ended March 31, 2013 and March 31, 2012, respectively. For ComEd, the majority of these costs are expected to be recovered over a five-year period. BGE established a regulatory asset of $16 million during the three months ended March 31, 2012, and the majority of these costs will be recovered over a five-year period. These costs are not included in the table above.

(c) Costs to integrate Constellation processes and systems into Exelon and to terminate certain Constellation debt agreements. ComEd established a regulatory asset of $3 million and $4 million during the three months ended March 31, 2013 and 2012, respectively, for certain other merger and integration costs, which are not included in the table above. BGE established a regulatory asset of $2 million during the three months ended March 31, 2013 for certain other merger integration costs, which are not included in the table above.
(d) BGE established a regulatory asset of $6 million at March 31, 2013 for certain 2012 other merger integration costs as part of the 2013 electric and gas distribution rate case order.
(e) External, third-party costs paid to advisors, consultants, lawyers and other experts to assist in the due diligence and regulatory approval processes and in the closing of the transaction.

As of March 31, 2013, Exelon projects incurring total additional merger-related expenses, primarily in 2013, of approximately $165 million.

Pursuant to the conditions set forth by the MDPSC in its approval of the merger transaction, Exelon committed to provide a package of benefits to BGE customers, and make certain investments in the City of Baltimore and the State of Maryland, resulting in an estimated direct investment in the State of Maryland of 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 twenty year lease agreement that is contingent upon the developer obtaining financing for the construction of the building. Once the financing conditions are met, construction of the building will commence and is expected to be ready for occupancy in 2 years. The direct investment estimate also includes $625 million in expenditures relating to the development of 285-300 MW of new electric generation facilities in Maryland (expected to be completed over the next ten years).

Exelon's Strategy and Outlook for the remainder of 2013 and Beyond

Exelon's value proposition and competitive advantage come from its scope and scale across the energy value chain and its core strengths of operational excellence and financial discipline.

On March 12, 2012, the Exelon and Constellation merger was completed. The merger creates incremental strategic value by matching Exelon's clean generation fleet with Constellation's leading customer-facing platform, as well as creating economies of scale through expansion across the energy value chain. Exelon supports customer switching to alternative electric generation suppliers and the addition of Constellation's competitive retail operations provides another outlet for Exelon to grow its business in competitive markets.

Generation is managed as an integrated business and is located in multiple geographic regions, with multiple supply sources and provides various energy commodities through multiple distribution channels. Generation's nuclear, fossil fuel, hydroelectric and renewables strategy is to pursue opportunities that provide generation to load matching and that diversify the generation fleet by expanding its regional and technological footprint. Generation's customer-facing activities enhance and expand across states its existing customer platform, and develop innovative products for its customers.

Exelon's utility strategy is to improve reliability and operations and enhance the customer experience, while ensuring ratemaking mechanisms provide the utilities fair financial returns. Exelon seeks to leverage its scale and expertise across the utilities platform by standardization and sharing of best practices to achieve improved operational and financial results.

Exelon's financial priorities are to maintain investment grade credit metrics at each of Exelon, Generation, ComEd, PECO and BGE, and to return value to Exelon's shareholders with a sustainable dividend throughout the energy commodity market cycle and through earnings growth from attractive investment opportunities.

In pursuing its strategies, Exelon has exposure to various market and financial risks, including the risk of price fluctuations in the power markets. Power prices are a function of supply and demand, which in turn are driven by factors such as (1) the price of fuels, in particular, the prices of natural gas and coal, which drive the market prices that Generation's power plants can obtain for their output, (2) the rate of expansion of subsidized low carbon generation in the markets in which Generation's output is sold, (3) the effects on energy demand of factors such as weather, economic conditions and implementation of energy efficiency and demand response programs, and (4) the impacts of increased competition in the retail channel.

Power Markets

Price of Fuels. The use of new technologies to recover natural gas from shale deposits is increasing natural gas supply and reserves, which places downward pressure on natural gas prices and, therefore, on wholesale and retail power prices, which results in a reduction in Exelon's revenues. Since the third quarter of 2011, forward natural gas prices for 2013 and 2014 have declined significantly; in part reflecting an increase in supply due to strong natural gas production (due to shale gas development).

Subsidized Generation. The rate of expansion of subsidized low carbon generation such as wind and solar energy in the markets in which Generation's output is sold can negatively impact wholesale power prices, and in turn, Generation's results of operations.

Various states have implemented or proposed legislation, regulations or other policies to subsidize new generation development which may result in artificially depressed wholesale energy and capacity prices. For example, on April 12, 2012, the MDPSC issued an order directing the Maryland electric utilities to enter into a 20-year contract for differences (CfD) with CPV Maryland, LLC (CPV), under which CPV will construct an approximately 700 MW combined cycle gas turbine in Waldorf, Maryland, that it projected will be in commercial operation by June 1, 2015. The CfD mandates that utilities (including BGE) pay (or receive) the difference between CPV's contract price and the revenues it receives for capacity and energy from clearing the unit in the PJM capacity market.

Similarly, in January 2011, New Jersey passed legislation that provides guaranteed cost recovery through a CfD for the development of up to 2,000 MWs of new base load or mid-merit generation, so long as it clears in PJM's capacity market. Three generation developers were chosen for the New Jersey CfD, for which contracts were executed in 2011 by the state's utilities under protest. Similarly, in Illinois, legislation has been debated for over four years that passed in the Senate and is currently being considered in the House which would require consumers to subsidize the development of an Integrated Gasification Combined Cycle plant by purchasing its electricity through 30 year power purchase agreements at prices significantly above market prices. A new version was recently introduced in the current Illinois General Assembly but its prospects are unclear at this time.

Exelon and others filed a complaint in federal district court challenging the constitutionality and other aspects of the New Jersey legislation. Similarly, Exelon and others are also challenging the selection of the three generation developers in New Jersey state court proceedings and the MDPSC actions in Maryland state court.

As required under their CfDs, two of the New Jersey generator developers and one in Maryland offered and cleared in PJM's capacity market auction held in May 2012. Given the state-required customer subsidy provided under their respective CfDs, Exelon believes that these projects may have artificially suppressed capacity prices in PJM in this auction and may continue to do so in future auctions to the detriment of Exelon's market driven position. PJM's capacity market rules include a Minimum Offer Pricing Rule (MOPR) that is intended to preclude sellers from artificially suppressing the competitive price signals for generation capacity. However, Exelon does not believe that the existing MOPR worked effectively with respect to the abovementioned generator developers. Accordingly, Exelon worked with other market stakeholders, PJM and PJM's independent market monitor to develop a new MOPR that would more effectively preclude such artificial price suppression, and PJM, after extensive stakeholder consideration, filed its new MOPR seeking FERC approval in December, 2012. On February 5, 2013, FERC issued a letter finding that PJM's new MOPR filing is deficient and requested 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. See Note 5 of the Combined Notes to Consolidated Financial Statements for further details of PJM's MOPR.

A continuation of these state efforts, if successful and unabated by an effective MOPR, could continue to result in artificially depressed wholesale capacity and/or energy prices. Other states could seek to establish similar programs, which could substantially impair Exelon's market driven position and could have a material effect on Exelon's financial results of operations, financial position and cash flows.

Energy Demand. The continued tepid economic environment and growing energy efficiency initiatives have limited the demand for electricity across the Exelon utilities. ComEd is projecting load volumes to remain essentially flat in 2013 compared to 2012, while PECO and BGE are projecting an increase (decrease) of 0.5% and (1.1%), respectively, in 2013 compared to 2012. The projected increase at PECO is a result of the oil refineries returning to full production and improved employment outlook in its service territory offset by the continued energy efficiency initiatives and the additional day in 2012 for the leap year. The projected decline at BGE is a result of the idling of a significant customer, energy efficiency initiatives and the additional day in 2012 for the leap year, partially offset by improving economic conditions. See Note 5 of the Combined Notes to Consolidated Financial Statements for further discussion of energy efficiency and demand response programs.

Retail Competition. Generation's retail operations compete for customers in a competitive environment, which affect the margins that Generation can earn and the volumes that it is able to serve. Recently, sustained low forward natural gas and power prices and low market volatility have caused retail competitors to aggressively pursue market share, and wholesale generators (including Generation) to use their retail operations to hedge generation output. These factors have adversely affected overall gross margins and profitability in Generation's retail operations.

Strategic Policy Alignment

Exelon routinely reviews its hedging policy, dividend policies, operating and capital costs, capital spending plans, strength of its balance sheet and credit metrics, and sufficiency of its liquidity position, by performing various stress tests with differing variables, such as commodity price movements, increases in margin-related transactions, changes in hedging practices, and the impacts of hypothetical credit downgrades.

Exelon's Board of Directors declared the first quarter 2013 dividend of $0.525 per share, and in response to low forward energy prices and weaker financial expectations, among other factors, Exelon's Board of Directors approved a revised dividend policy going forward. The first quarter dividend was paid on March 8, 2013 to shareholders of record on February 19, 2013 and was based on Exelon's previous dividend of $2.10 per share on an annualized basis. The second quarter dividend will be based on Exelon's new dividend policy of $0.31 per share quarterly dividend ($1.24 per share on an annualized basis). Consistent with past practice, all future quarterly dividends will require approval by Exelon's Board of Directors.

Continuation of recent power price volatility and demand trends could adversely affect the Registrants' ability to fund discretionary uses of cash such as growth projects and dividends. In addition, economic conditions may no longer support the continued operation of certain generating facilities, which could adversely affect Generation's results of operations through increased depreciation rates, impairment charges and accelerated future decommissioning costs.

Hedging Strategy

Exelon's policy to hedge commodity risk on a ratable basis over three-year periods is intended to reduce the financial impact of market price volatility. Generation is exposed to commodity price risk associated with the unhedged portion of its electricity portfolio. Generation enters into non-derivative and derivative contracts, including financially settled swaps, futures contracts and swap options, and physical options and physical forward contracts, all with credit-approved counterparties, to hedge this anticipated exposure. Generation has hedges in place that significantly mitigate this risk for 2013 and 2014. However, Generation is exposed to relatively greater commodity price risk in the subsequent years with respect to which a larger portion of its electricity portfolio is currently unhedged. As of 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 of energy to ComEd, PECO and BGE relating to their respective retail load obligations. Generation has been and will continue to be proactive in using hedging strategies to mitigate commodity price risk in subsequent years as well.

Generation procures coal, oil and natural gas through long-term and short-term contracts and spot-market purchases. Nuclear fuel is obtained predominantly through long-term uranium concentrate supply contracts, contracted conversion services, contracted enrichment services and contracted fuel fabrication services. The supply markets for uranium concentrates and certain nuclear fuel services, coal, oil and natural gas are subject to price fluctuations and availability restrictions. Supply market conditions may make Generation's procurement contracts subject to credit risk related to the potential non-performance of counterparties to deliver the contracted commodity or service at the contracted prices. Approximately 60% of Generation's uranium concentrate requirements from 2013 through 2017 are supplied by three producers. In the event of non-performance by these or other suppliers, Generation believes that replacement uranium concentrates can be obtained, although at prices that may be unfavorable when compared to the prices under the current supply agreements. Non-performance by these counterparties could have a material adverse impact on Exelon's and Generation's results of operations, cash flows and financial position. ComEd, PECO and BGE mitigate such exposure through regulatory mechanisms that allow them to recover procurement costs from retail customers.

New Growth Opportunities

Nuclear Uprate Program. Generation is engaged in individual projects as part of a planned power uprate program across its nuclear fleet. Using proven technologies, the projects take advantage of new production and measurement technologies, new materials and application of expertise gained from a half-century of nuclear power operations. The uprates are being undertaken pursuant to an organized, strategically sequenced implementation plan. The implementation effort includes a periodic review and refinement of the plan in light of changing market conditions. Decisions to implement uprates at particular nuclear plants, the amount of expenditures to implement the plan, and the actual MWs of additional capacity attributable to the uprate program will be determined on a project-by-project basis in accordance with Exelon's normal project evaluation standards and ultimately will depend on market conditions, economic and policy considerations, and other factors.

Based on recent reviews, the nuclear uprate implementation plan was adjusted during 2013 to cancel certain projects, as a result of the cost of additional plant modifications identified during final design work which combined with current market conditions, including low natural gas prices and the continued sluggish economy, made these projects not economically viable. For these cancelled projects, Generation recorded approximately $21 million of operating and maintenance expense during the first quarter of 2013 to reverse the previously capitalized costs. In addition, the ability to implement several projects requires the successful resolution of various technical matters. The resolution of these matters may further affect the timing and amount of the power increases associated with the power uprate initiative. Following these reviews, any projects that may be undertaken are expected to be completed by the end of 2021, and may result in between 1,075 and 1,125 MWs of additional capacity at an overnight cost of approximately $3.3 billion in 2013 dollars. Overnight costs do not include financing costs or cost escalation.

Approximately 75% of the planned uprate MWs projects are either complete and in service or in the installation or design and engineering phases across seven nuclear stations including Limerick and Peach Bottom in Pennsylvania and Byron, Braidwood, Dresden, LaSalle and Quad Cities in Illinois. The remaining 25% of uprate MWs, if and when completed, would come from an extended power uprate project at Limerick currently scheduled to begin in 2017. From the program announcement in 2008 through March 31, 2013, Generation has placed in service 310 MWs of nuclear generation through the uprate program at a cost of approximately $855 million, which has been capitalized to property, plant and equipment on Exelon's and Generation's consolidated balance sheets. At March 31, 2013, an additional approximate $270 million has been capitalized to construction work in progress (CWIP) within property, plant and equipment on Exelon's and Generation's consolidated balance sheets, of which approximately $170 million (202 MWs) relates to projects currently in the installation phase. The remaining $100 million (300 MWs) in CWIP relates to projects currently in the design and engineering phase that continue to be evaluated in accordance with Exelon's normal project evaluation standards. The completion of those projects in the design and engineering phase will ultimately depend on market conditions, economic and policy considerations, and other factors. As of March 31, 2013, Generation believes it is more likely than not that all projects in CWIP will ultimately be placed in service. If a project in the design and engineering phase is expected to not be completed as planned, previously capitalized costs would be reversed through earnings as a charge to operating and maintenance expense.

Generation Renewable Development. On September 30, 2011, Exelon announced the completion of its acquisition of all of the interests in Antelope Valley, a 230-MW solar photovoltaic (PV) project under development in northern Los Angeles County, California, from First Solar, Inc., which developed and will build, operate, and maintain the project. The first portion of the project began operations in December 2012, with three additional blocks coming online in the first quarter of 2013 and an expectation of full commercial operation in December 2013. The acquisition supports the Exelon commitment to renewable energy as part of Exelon 2020. The project has a 25-year PPA, approved by the CPUC, with Pacific Gas & Electric Company for the full output of the plant. Upon completion, the facility will add 230 MWs to Generation's renewable generation fleet. Total capitalized costs for the facility are expected to be approximately $1.1 billion. Total capitalized costs incurred through March 31, 2013 were approximately $840 million. Additionally, Generation constructed and placed into service six wind facilities in 2012, resulting in approximately 400 MWs of additional renewable generation. Total costs for the facilities were approximately $700 million.

Smart Meter and Smart Grid Initiatives.

ComEd's Smart Meter and Smart Grid Investments. On December 5, 2012, the ICC approved ComEd's revised AMI Deployment Plan which includes the planned installation of 4 million electric smart meters. ComEd plans to invest approximately $1.3 billion on smart meters and smart grid under EIMA, including $1.0 billion through the AMI Deployment Plan.

PECO's Smart Meter and Smart Grid Investments. In 2010, the PAPUC approved PECO's Smart Meter Procurement and Installation Plan, under which PECO will install more than 1.6 million smart meters. PECO plans to spend up to a total of $595 million and $120 million on its smart meter and smart grid infrastructure, respectively, before considering the $200 million SGIG.

BGE Smart Grid Initiative. In August 2010, the MDPSC approved a comprehensive smart grid initiative for BGE which includes the planned installation of 2 million electric and gas smart meters at an expected total cost of approximately $480 million, before considering the $200 million SGIG for smart grid and other related initiatives.

See Note 5 of the Combined Notes to Consolidated Financial Statements for additional information on the Smart Meter and Smart Grid Initiatives.

Liquidity

Each of the Registrants annually evaluates its financing plan, dividend practices and credit line sizing, focusing on maintaining its investment grade ratings while meeting its cash needs to fund capital requirements, retire debt, pay dividends, fund pension and other postretirement benefit obligations and invest in new and existing ventures. The Registrants expect cash flows to be sufficient to meet operating expenses, financing costs and capital expenditure requirements.

Exelon, Generation, ComEd, PECO and BGE have unsecured syndicated revolving credit facilities with aggregate bank commitments of $0.5 billion, $5.3 billion, $1.0 billion, $0.6 billion and $0.6 billion, respectively. Generation also has bilateral credit facilities with aggregate maximum availability of $0.4 billion.

Exposure to Worldwide Financial Markets. Exelon has exposure to worldwide financial markets. The ongoing European debt crisis has contributed to the instability in global credit markets. Further disruptions in the European markets could reduce or restrict the Registrants' ability to secure sufficient liquidity or secure liquidity at reasonable terms. As of March 31, 2013, approximately 30%, or $2.5 billion, of the Registrants' aggregate total commitments were with European banks. The credit facilities include $8.4 billion in aggregate total commitments of which $6.7 billion was available as of March 31, 2013. There were no borrowings under the Registrants' credit facilities as of March 31, 2013. See Note 10 of the Combined Notes to the Consolidated Financial Statements for additional information on the credit facilities.

Tax Matters

Exelon has exposure related to various uncertain tax positions which Exelon manages through planning and implementation of tax planning strategies. See Note 11 of the Combined Notes to Consolidated Financial Statements for additional information.

Environmental Legislative and Regulatory Developments.

Exelon supports the promulgation of certain environmental regulations by the U.S. EPA, including air, water and waste controls for electric generating units. See discussion below for further details. The air and waste regulations will have a disproportionate adverse impact on fossil-fuel power plants, requiring significant expenditures of capital and variable operating and maintenance expense, and will likely result in the retirement of older, marginal facilities. Due to their low emission generation portfolio, Generation and CENG will not be significantly directly affected by these regulations, representing a competitive advantage relative to electric generators that are more reliant on fossil-fuel plants. Various bills have been introduced in the U.S. Congress that would prohibit or impede the U.S. EPA's rulemaking efforts. The timing of the consideration of such legislation is unknown.

Air Quality. In recent years, the U.S. EPA has been implementing a series of increasingly stringent regulations under the Clean Air Act relating to NAAQS for conventional air pollutants (e.g., NO_x, SO_2 and particulate matter) as well as stricter technology requirements to control HAPs (e.g., acid gases, mercury and other heavy metals) from electric generation units. The U.S. EPA continues to review and update its NAAQS with a tightened particulate matter NAAQS issued in December 2012 and a review of the current 2008 ozone NAAQS that is expected to result in a final revised ozone NAAQS sometime in 2014. These updates will potentially result in more stringent emissions limits on fossil-fuel electric generating stations. There continues to be opposition among fossil-fuel generation owners to the potential stringency and timing of these air regulations.

In July 2011, the U.S. EPA published CSAPR and in June 2012, it issued final technical corrections. CSAPR required 28 upwind states in the eastern half of the United States to significantly improve air quality by reducing power plant emissions that cross state lines and contribute to ground-level ozone and fine particle pollution in downwind states. On August 21, 2012, a three-judge panel of the D.C. Circuit Court held that the U.S. EPA had exceeded its authority in certain material aspects with respect to CSAPR and vacated the rule and remanded it to the U.S. EPA for further rulemaking consistent with its decision. The Court also ordered that CAIR remain in effect pending finalization of CSAPR on remand. Until the U.S. EPA re-issues CSAPR, Exelon cannot determine the impacts of the rule, including any that would impact power prices. In March 2013, the U.S. EPA petitioned the U.S. Supreme Court to review the D.C. Circuit Court's CSAPR decision, and Exelon has filed in support of the U.S. EPA's petition.

On December 16, 2011, the U.S. EPA signed a final rule to reduce emissions of toxic air pollutants from power plants and signed revisions to the NSPS for electric generating units. The final rule, known as MATS, requires coal-fired electric generation plants to achieve high removal rates of mercury, acid gases and other metals. To achieve these standards, coal units with no pollution control equipment installed (uncontrolled coal units) will have to make capital investments and incur higher operating expenses. It is expected that owners of smaller, older, uncontrolled coal units will retire the units rather than make these investments. Coal units with existing controls that do not meet the MATS rule may need to upgrade existing controls or add new controls to comply. Owners of oil units not currently meeting the proposed emission standards may choose to convert the units to light oils or natural gas, install control technologies, or retire the units. Numerous entities have challenged MATS in the D.C. Circuit Court, and Exelon has been granted permission by the Court to intervene in support of the rule. A decision by the Court is expected sometime in 2013. The outcome of the appeal, and its impact on power plant operators' investment and retirement decisions, is uncertain.

The cumulative impact of these air regulations could be to require power plant operators to expend significant capital to install pollution control technologies, including wet flue gas desulfurization technology for SO_2 and acid gases, and selective catalytic reduction technology for NO_x. Exelon, along with the other co-owners of Conemaugh Generating Station are moving forward with plans to improve the existing scrubbers and install Selective Catalytic Reduction (SCR) controls to meet the mercury removal requirements of MATS by January 1, 2015. In addition, Keystone already has SCR and Flue-gas desulfurization (FGD) controls in place.

On January 15, 2013, EPA issued a final rule for New Source Performance Standards (NSPS) and National Emissions Standards for Hazardous Air Pollutants (NESHAP) for reciprocating internal combustion engines (RICE NESHAP/NSPS). The final rule allows diesel backup generators to operate for up to 100 hours annually under certain emergency circumstances without meeting emissions limitations, but requires units that operate over 15 hours to burn low sulfur fuel and report key engine information. The final rule eliminates after May 2014 the 50 hour exemption for peak shaving and other non-emergency demand response that was included in the proposed rule, and therefore, is not expected to result in additional megawatts of demand response to be bid into the PJM capacity auction.

In the absence of Federal legislation, the U.S. EPA is also moving forward with the regulation of GHG emissions under the Clean Air Act, including permitting requirements under the Prevention of Significant Deterioration (PSD) and Title V operating permit sections of the Clean Air Act for new and modified stationary sources that became effective January 2, 2011. On April 13, 2012, the U.S. EPA published proposed regulations for NSPS for GHG emissions from new fossil-fueled power plants greater than 25 MW that would require the plants to limit CO_2 emissions. Under the PSD regulations, new and modified major stationary sources could be required to install best available control technology, to be determined on a case-by-case basis. The U.S. EPA is also expected to establish in 2013 GHG emission regulations for existing stationary sources under Section 111(d) of the Clean Air Act. It is not yet known what the nature and impact of the final regulations will be.

Exelon supports comprehensive climate change legislation or regulation, including a cap-and-trade program for GHG emissions, which balances the need to protect consumers, business and the economy with the urgent need to reduce national GHG emissions.

Water Quality. Section 316(b) of the Clean Water Act requires that cooling water intake structures at electric power plants reflect the best technology available to minimize adverse environmental impacts, and is implemented through state-level NPDES permit programs. On March 28, 2011, the U.S. EPA issued a proposed rule, and is required under a Settlement Agreement to issue a final rule by July 27, 2013. The proposed rule does not require closed cycle cooling (e.g., cooling towers) as the best technology available, and also provides some flexibility in the use of cost-benefit considerations and site-specific factors. The proposed rule affords the state permitting agency wide discretion to determine the best technology available, which, depending on the site characteristics, could include closed cycle cooling, advanced screen technology at the intake, or retention of the current technology.

It is unknown at this time whether the final regulations will require closed-cycle cooling. The economic viability of Generation's facilities without closed-cycle cooling water systems will be called into question by any requirement to construct cooling towers. Should the final rule not require the installation of cooling towers, and retain the flexibility afforded the state permitting agencies in applying a cost – benefit test and to consider site-specific factors, the impact of the rule would be minimized even though the costs of compliance could be material to Generation.

Hazardous and Solid Waste. Under proposed U.S. EPA rules issued on June 21, 2010, coal combustion residuals (CCR) would be regulated for the first time under the RCRA. The U.S. EPA is considering several options, including classification of CCR either as a hazardous or non-hazardous waste, under RCRA. Under either option, the U.S. EPA's intention is the ultimate elimination of surface impoundments as a waste treatment process. For plants affected by the proposed rules, this would result in significant capital expenditures and variable operating and maintenance expenditures to convert to dry handling and disposal systems and installation of new waste water treatment facilities. Generation's plants that would be affected by the proposed rules are Keystone and Conemaugh in Pennsylvania, which have on-site landfills that meet the requirements of Pennsylvania solid waste regulations for non-hazardous waste disposal. However, until the final rule is adopted, the impact on these facilities is unknown. The U.S. EPA has not announced a target date for finalization of the CCR rules.

See Note 17 of the Combined Notes to Consolidated Financial Statements for further detail related to environmental matters, including the impact of environmental regulation.

Other Regulatory and Legislative Actions

Japan Earthquake and Tsunami and the Nuclear Industry's Response. On March 11, 2011, Japan experienced a 9.0 magnitude earthquake and ensuing tsunami that seriously damaged the nuclear units at the Fukushima Daiichi Nuclear Power Station, which are operated by Tokyo Electric Power Co.

Generation believes its nuclear generating facilities do not have the same operating risks as the Fukushima Daiichi plant because they meet the NRC's requirement that specifies all plants must be able to withstand the most severe natural phenomena historically reported for each plant's surrounding area, with a significant margin for uncertainty. In addition, Generation's plants are not located in significant earthquake zones or in regions where tsunamis are a threat. Generation believes its nuclear generating facilities are able to shut down safely and keep the fuel cooled through multiple redundant systems specifically designed to maintain electric power when electricity is lost from the grid. Further, Generation's nuclear generating facilities also undergo frequent scenario drills to ensure the proper function of the redundant safety protocols.

Since the events in Japan took place, Generation has continued to work with regulators and nuclear industry organizations to understand the events in Japan and apply lessons learned. Early on, the nuclear industry took a number of specific steps to respond, including actions requested by the Institute of Nuclear Power Operations (INPO) to perform tests that verified Generation's emergency equipment is available and functional, conduct walk-downs on its procedures related to critical safety equipment, confirm event response procedures and readiness to protect the spent fuel pool, and verify current qualifications of operators and support staff needed to implement the procedures. Generation has been addressing additional actions requested by INPO for improving and maintaining core and spent fuel pool cooling during an extended loss of power for at least 24 hours.

In April 2011, the NRC named six senior managers and staff to its task force for examining the agency's regulatory requirements, programs, processes, and implementation in light of information from the Fukushima Daiichi site in Japan, following the March 11 earthquake and tsunami (Task Force). On July 12, 2011, the NRC Task Force issued a report of its review of the accident, including recommendations for future regulatory action by the NRC to be taken in the near and longer term. The Task Force's report concluded that nuclear reactors in the United States are operating safely and do not present an imminent risk to public health and safety. The Task

Force's report did not recommend any changes to the existing nuclear licensing process in the United States or changes in the storage of spent nuclear fuel within the plant's spent nuclear fuel pools. During the fourth quarter of 2011, the NRC staff issued its recommendations for prioritizing and implementing the Task Force recommendations and an implementation schedule which was approved by the NRC subject to a number of conditions. The NRC staff confirmed the Task Force's conclusions that none of the findings arising from the Task Force review presented an imminent risk to public health and safety.

In March 2012, the NRC authorized its staff to issue three immediately effective orders to commercial reactor licensees operating in the United States for compliance no later than December 31, 2016. In summary, the orders require licensees: (1) to provide sufficient onsite portable equipment and resources to maintain or restore cooling capabilities for the containment, core, and spent fuel pool until offsite equipment is available and have offsite equipment and resources available to sustain cooling functions indefinitely; (2) to improve the venting systems with boiling water reactor Mark I or Mark II containments (or for the Mark II plants, install new systems) that help prevent or mitigate core damage in the event of a serious accident by making the systems accessible and operable in the event of a prolonged station blackout and inadequate cooling; and (3) to install instrumentation to provide a reliable indication of water level in the spent fuel pool.

Additionally, the NRC has issued a detailed information request to every operating commercial nuclear power plant in the United States. The information requested requires: (1) use of the current NRC guidance to reevaluate current seismic and flood risk hazards against the design basis and provide a plan of actions to address vulnerabilities, including risks exceeding the design basis; (2) performance of walk downs to ensure the ability to respond to seismic and external flooding events and provide a corrective action plan to the NRC to address deficiencies; and (3) assessment of the means to provide power for communications equipment during a severe natural event and identify staffing required to implement the emergency plan for an event affecting all units with an extended loss of alternating current power and impeded access to the site. In November 2012, the NRC staff recommended to the NRC the installation of engineered containment filtered venting systems for boiling-water reactors with Mark I and Mark II containment structures. On March 19, 2013, the NRC issued a Staff Requirements Memorandum (SRM) related to venting requirements for boiling water reactor Mark I or Mark II containments. In the SRM, the Commissioners call for the NRC staff to (1) issue an enhancement to the March 2012 order within 60 days to require vents to remain functional during severe accident conditions, and (2) produce a technical evaluation to support rulemaking that considers filtering and performance-based strategies as options. The NRC staff must then develop a final rule by March 2017.

Generation has assessed the impacts of the orders and information requests and will continue monitoring the additional recommendations under review by the staff, both from an operational and a financial impact standpoint. A comprehensive review of the NRC Tier 1 orders and information requests, as well as preliminary engineering assumptions and analysis, indicate that the financial impact of compliance is expected to be approximately $350 million and $50 million of capital and operating expense, respectively, from 2013 through 2017, as previously anticipated in Generation's planning projections. In addition, Generation estimates incremental costs of $15 to $20 million per unit at eleven Mark I and II units for the installation of filtered vents, if ultimately required by the NRC. Generation's current assessments are specific to the Tier 1 recommendations as the NRC has not taken specific action with respect to the Tier 2 and Tier 3 recommendations. Exelon and Generation are unable to conclude at this time to what extent any actions to comply with the requirements of Tier 2 and Tier 3 will impact their future financial position, results of operations, and cash flows. Generation will continue to engage in nuclear industry assessments and actions and stakeholder input. See Item 1A. Risk Factors of the Exelon 2012 Form 10-K, for further discussion of the risk factors.

Generation will continue to monitor NRC directives and guidance that may impact the uprates and, as it has in the past, evaluate each project at the appropriate time and cancel or defer any uprate project that is not considered economical, whether due to energy prices, potential increased regulation, or other factors.

Financial Reform Legislation. The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) was enacted in July 2010. While the Dodd-Frank Act is focused primarily on the regulation and oversight of financial institutions, it also provides for a new regulatory regime for over-the-counter swaps (Swaps), including mandatory clearing, exchange trading, margin requirements, and other transparency requirements. The Dodd-Frank Act, however, also preserves the ability of end users in the energy industry to hedge their risks. In April 2012, the CFTC issued its rule defining swap dealers and major swap participants. Exelon has determined that it will conduct its commercial business in a manner that does not require registration as a swap dealer or major swap participant. Notwithstanding, there are additional rulemakings that have not yet been issued, including the capital and margin rules, which will further define the scope of the regulations and provide clarity as to the impact on the Registrants' business, as well as to potential new opportunities. Depending on these final rules, the Registrants could be subject to significant new obligations.

The proposed regulations addressing collateral and capital requirements and exchange margin cash postings, when final, could require Generation to increase collateral requirements or cash postings in lieu of letters of credit currently issued to collateralize Swaps. Exelon had previously estimated that it could be required to make up to $1 billion of additional collateral postings under its bilateral credit lines. Given the swap dealer and the major swap participant definitions will not apply to Generation, the actual amount of collateral postings that will be required may be lower than Exelon's previous expectations due to the following factors: (a) the majority of Generation's physical wholesale portfolio does not meet the final CFTC Swap definition; (b) there will be minimal incremental costs associated with Generation's positions that are currently cleared and subject to exchange margin; and (c) Generation will not be a swap dealer or major swap participant and proposed capital requirements applicable to these entities will not apply to Generation.

The actual level of collateral required will depend on many factors, including but not limited to market conditions, the outcome of final margin rules for Swaps, the extent of its trading activity in Swaps, and Generation's credit ratings. Nonetheless, Generation has adequate credit facilities and flexibility in its hedging program to meet its anticipated collateral requirements estimated based on conservative assumptions.

In addition, the new regulations will impose new and ongoing compliance and infrastructure costs on Generation, which may amount to several million dollars per year.

Exelon and Generation continue to monitor the rulemaking procedures and cannot predict the ultimate outcome that the financial reform legislation will have on their results of operations, cash flows or financial position.

ComEd, PECO and BGE could also be subject to various Dodd-Frank Act requirements to the extent they enter into Swap transactions. However, at this time, management of ComEd, PECO and BGE do not expect to be materially affected by this legislation.

Energy Infrastructure Modernization Act. Since 2011, ComEd's distribution rates are established through a performance-based rate formula, pursuant to EIMA. EIMA also provides a structure for substantial capital investment by utilities over a ten-year period to modernize Illinois' electric utility infrastructure. In addition, as long as ComEd is subject to EIMA, ComEd will fund customer assistance programs for low-income customers, which amounts will not be recoverable through rates.

ComEd files an annual reconciliation of the revenue requirement in effect in a given year to reflect the actual costs that the ICC determines are prudently and reasonably incurred for such year. Under the terms of EIMA, ComEd's target rate of return on common equity is subject to reduction if ComEd does not deliver the reliability and customer service benefits, as defined, it has committed to over the ten-year life of the investment program.

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: average vs. year-end rate base ad capital structure, return on pension asset, and a weighted average cost of capital interest rate on the prior year reconciliation. 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.

See Note 5 of the Combined Notes to Consolidated Financial Statements for additional information.

FERC Ameren Order. In July 2012, FERC issued an order indicating that Ameren Corporation (Ameren) had improperly included acquisition premiums/goodwill in its transmission formula rate, particularly in its capital structure and in the application of AFUDC. FERC also directed Ameren to make refunds for the implied increase in rates in prior years. Ameren has filed for rehearing regarding the July 2012 FERC order. ComEd believes that the FERC order authorizing its transmission formula rate is distinguishable from the circumstances that led to the July 2012 FERC order in the Ameren case. However, if ComEd were required to exclude acquisition premiums/goodwill from its transmission formula rate, the impact could be material to ComEd's results of operations and cash flows.

FERC Order No. 1000 Compliance. In FERC Order No. 1000, the FERC required public utility transmission providers to enhance their transmission planning procedures and their cost allocation methods applicable to certain new regional and interregional transmission projects. As part of the changes to the transmission planning procedures, the FERC required removal from all FERC-approved tariffs and agreements a federal right of first refusal to build certain new transmission facilities. In compliance with the regional transmission planning requirements of Order No. 1000, PJM as the transmission provider submitted a compliance filing to FERC on October 25, 2012. On the same day, certain of the PJM transmission owners including ComEd, PECO and BGE (collectively, the PJM Transmission Owners) submitted a filing asserting that their contractual rights embodied in the PJM governing documents continue to justify their right of first refusal to construct new reliability (and related) transmission projects and that the FERC should not be allowed to override such rights absent a showing that it is in the public interest to do so under the FERC's "*Mobile-Sierra*" standard of review. This is a heightened standard of review which the PJM Transmission Owners argued could not be satisfied based on the facts applicable to them. On March 22, 2013, FERC issued an order on the PJM Compliance Filing and the filing of these PJM Transmission Owners (1) rejecting the arguments of such PJM Transmission Owners that the PJM governing documents were entitled to review under the *Mobile-Sierra* standard, (2) accepting most of the PJM filing, removing the right-of-first refusal from the PJM tariffs; and (3) directing PJM to remove certain exceptions that it included in its compliance filing that FERC found did not comply with Order No. 1000. FERC's order could enable third parties to seek to build certain regional transmission projects that had previously been reserved for the PJM Transmission Owners, potentially reducing ComEd's, PECO's and BGE's financial return on new investments in energy transmission facilities.

FERC Transmission Complaint. 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. 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.

See Note 5 of the Combined Notes to Consolidated Financial Statements for additional information.

Critical Accounting Policies and Estimates

Management of each of the Registrants makes a number of significant estimates, assumptions and judgments in the preparation of its financial statements. See "Management's Discussion and Analysis of Financial Condition and Results of Operations — Critical Accounting Policies and Estimates" in the Exelon's, Generation's, ComEd's, PECO's and BGE's combined 2012 Form 10-K for a discussion of the estimates and judgments necessary in the Registrants' accounting for AROs, purchase accounting, asset impairments, depreciable lives of property, plant and equipment, defined benefit pension and other postretirement benefits, regulatory accounting, derivative instruments, taxation, contingencies and revenue recognition. At March 31, 2013, the Registrants' critical accounting policies and estimates had not changed significantly from December 31, 2012.

Results of Operations

Net Income (Loss) on Common Stock by Registrant

	Three Months Ended March 31,		Favorable (Unfavorable) Variance
	2013	2012(a)	
Exelon	$ (4)	$ 200	$ (204)
Generation	(18)	168	(186)
ComEd	(81)	87	(168)
PECO	121	96	25
BGE	77	(33)	110

(a) For BGE, reflects BGE's operations for the three months ended March 31, 2012. For Exelon and Generation, includes the operations of the acquired businesses from the date of the merger, March 12, 2012, through March 31, 2012.

Results of Operations — Generation

	Three Months Ended March 31,		Favorable (Unfavorable) Variance
	2013	2012	
Operating revenues	$3,533	$2,743	$ 790
Purchased power and fuel	2,169	1,044	(1,125)
Revenue net of purchased power and fuel(a)	1,364	1,699	(335)
Operating other expenses			
Operating and maintenance	1,112	1,179	67
Depreciation and amortization	214	153	(61)
Taxes other than income	93	73	(20)
Total other operating expenses	1,419	1,405	(14)
Equity in losses of unconsolidated affiliates	(9)	(22)	13
Operating income (loss)	(64)	272	(336)
Other income and deductions			
Interest expense	(82)	(54)	(28)
Other, net	128	178	(50)
Total other income and deductions	46	124	(78)
Income before income taxes	(18)	396	(414)
Income taxes	(1)	230	231
Net income (loss)	(17)	166	(183)
Net loss attributable to noncontrolling interests	1	(2)	(3)
Net income (loss) on common stock	$ (18)	$ 168	$ (186)

(a) Generation evaluates its operating performance using the measure of revenue net of purchased power and fuel expense. Generation believes that revenue net of purchased power and fuel expense is a useful measurement because it provides information that can be used to evaluate its operational performance. Revenue net of purchased power and fuel expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

Net Income (loss)

Generation's net income (loss) for the three months ended March 31, 2013 decreased compared to the same period in 2012 primarily due to lower revenue, net of purchased power and fuel, unfavorable NDT fund performance and higher depreciation expense; partially offset by lower operating and maintenance expense. The decrease in revenue, net of purchased power and fuel was primarily due to mark-to-market losses in 2013. The decrease in operating and maintenance expense was largely due to 2012 costs associated with a settlement with the FERC in March 2012 and a decrease in transaction costs and employee-related costs associated with the merger.

Revenue Net of Purchased Power and Fuel

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

- Mid-Atlantic represents operations in the eastern half of PJM, which includes Pennsylvania, New Jersey, Maryland, Virginia, West Virginia, Delaware, the District of Columbia and parts of North Carolina.
- Midwest represents operations in the western half of PJM, which includes portions of Illinois, Indiana, Ohio, Michigan, Kentucky and Tennessee, and the entire United States footprint of MISO, which covers all or most of North Dakota, South Dakota, Nebraska, Minnesota, Iowa, Wisconsin, the remaining parts of Illinois, Indiana, Michigan and Ohio not covered by PJM, and parts of Montana, Missouri and Kentucky.
- New England represents the operations within ISO-NE covering the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont.
- New York represents operations within New York ISO, which covers the state of New York in its entirety.
- ERCOT represents operations within Electric Reliability Council of Texas, covering most of the state of Texas.
- Other Regions not considered individually significant:
  - South represents operations in the FRCC and the remaining portions of the SERC not included within MISO or PJM, which includes all or most of Florida, Arkansas, Louisiana, Mississippi, Alabama, Georgia, Tennessee, North Carolina, South Carolina and parts of Missouri, Kentucky and Texas. Generation's South region also includes operations in the SPP, covering Kansas, Oklahoma, most of Nebraska and parts of New Mexico, Texas, Louisiana, Missouri, Mississippi and Arkansas.
  - West represents operations in the WECC, which includes California ISO, and covers the states of California, Oregon, Washington, Arizona, Nevada, Utah, Idaho, Colorado, and parts of New Mexico, Wyoming and South Dakota.
  - Canada represents operations across the entire country of Canada and includes the AESO, OIESO and the Canadian portion of MISO.

The following business activities are not allocated to a region, and are reported under Other: retail and wholesale gas, investments in natural gas exploration and production activities, proprietary trading, energy efficiency and demand response, the design, construction, and operation of renewable energy, heating, cooling, and cogeneration facilities, and home improvements, sales of electric and gas appliances, servicing of heating, air conditioning, plumbing, electrical, and indoor quality systems. Further, the following activities are not allocated to a region, and are reported in Other: compensation under the reliability-must-run rate schedule; results of operations from the Maryland Clean-Coal assets sold in the fourth quarter of 2012; unrealized mark-to-market impact of economic hedging activities; amortization of certain intangible assets relating to commodity contracts recorded at fair value as a result of the merger; and other miscellaneous revenues.

Generation evaluates the operating performance of its power marketing activities using the measure of revenue net of purchased power and fuel expense which is a non-GAAP measurement. Generation's operating revenues include all sales to third parties and affiliated sales to ComEd, PECO and BGE. Purchased power costs include all costs associated with the procurement and supply of electricity including capacity, energy and ancillary services. Fuel expense includes the fuel costs for internally generated energy and fuel costs associated with tolling agreements.

For the three months ended March 31, 2013 and 2012, Generation's revenue net of purchased power and fuel expense by region were as follows:

	Three Months Ended March 31,			
	2013	2012(a)	Variance	% Change
Mid-Atlantic(b)	$ 844	$ 770	$ 74	9.6%
Midwest(c)	717	817	(100)	(12.2)%
New England	30	39	(9)	(23.1)%
New York	(22)	8	(30)	n.m
ERCOT	101	34	67	n.m
Other Regions(d)	45	14	31	n.m.
Total electric revenue net of purchased power and fuel	1,715	1,682	33	2.0%
Proprietary Trading	9	(4)	13	n.m
Mark-to-market gains (losses)	(403)	60	(463)	n.m.
Other(e)	43	(39)	82	n.m.
Total revenue net of purchased power and fuel	$1,364	$ 1,699	$ (335)	(19.7)%

(a) Includes results for Constellation beginning on March 12, 2012, the date the merger was completed.
(b) Results of transactions with PECO and BGE are included in the Mid-Atlantic region.
(c) Results of transactions with ComEd are included in the Midwest region.
(d) Other Regions includes South, West and Canada, which are not considered individually significant.
(e) Other represents activities not allocated to a region. See text above for a description of included activities. Also includes amortization of intangible assets related to commodity contracts recorded at fair value at the merger date of $174 million and $122 million, for the three months ended March 31, 2013 and 2012, respectively.

Generation's supply sources by region are summarized below:

Supply source in GWh	Three Months Ended March 31, 2013	Three Months Ended March 31, 2012(a)	Variance	% Change
Nuclear generation(b)				
Mid-Atlantic	12,762	12,064	698	5.8%
Midwest	23,269	23,198	71	0.3%
Total Nuclear Generation	36,031	35,262	769	2.2%
Fossil and Renewables(b)				
Mid-Atlantic(b)(d)	3,160	1,791	1,369	76.4%
Midwest	581	272	309	113.6%
New England	2,392	889	1,503	n.m.
New York	—	—	—	0%
ERCOT	733	840	(107)	(12.7)%
Other Regions(e)	2,254	819	1,435	n.m.
Total Fossil and Renewables	9,120	4,611	4,509	97.8%
Purchased power				
Mid-Atlantic(c)	3,233	2,577	656	25.5%
Midwest	1,700	2,552	(852)	(33.4)%
New England	1,507	1,100	407	37.0%
New York(c)	3,511	935	2,576	n.m.
ERCOT	4,199	2,832	1,367	48.3%
Other Regions(e)	3,703	1,769	1,934	109.3%
Total Purchased Power	17,853	11,765	6,088	51.7%
Total supply/sales by region(f)				
Mid-Atlantic(g)	19,155	16,432	2,723	16.6%
Midwest(h)	25,550	26,022	(472)	(1.8)%
New England	3,899	1,989	1,910	96.0%
New York	3,511	935	2,576	n.m.
ERCOT	4,932	3,672	1,260	34.3%
Other Regions(e)	5,957	2,588	3,369	130.2%
Total supply/sales by region	63,004	51,638	11,366	22.0%

(a) Includes results for Constellation beginning on March 12, 2012, the date the merger was completed.
(b) Includes the proportionate share of output where Generation has an undivided ownership interest in jointly owned generating plants and does not include ownership through equity method investments (e.g., CENG).
(c) Purchased power for the three months ended March 31, 2013 includes physical volumes of 2,588 GWh in the Mid-Atlantic and 3,213 GWh in New York as a result of the PPA with CENG. Purchased power for the three months ended March 31, 2012 includes physical volumes of 319 GWh in the Mid-Atlantic and 722 GWh in New York as a result of the PPA with CENG.
(d) Excludes 2012 activity related to generation under the reliability-must-run rate schedule and generation of Brandon Shores, H.A. Wagner, and C.P. Crane, the generating facilities divested in the fourth quarter of 2012 as a result of the Exelon and Constellation merger.
(e) Other Regions includes South, West and Canada, which are not considered individually significant.
(f) Excludes physical proprietary trading volumes of 1,572 GWh and 1,888 GWh for the three months ended March 31, 2013 and 2012, respectively.
(g) Includes sales to PECO through the competitive procurement process of 1,921 GWh and 1,629 GWh for the three months ended March 31, 2013 and 2012, respectively. Sales to BGE of 1,535 GWh and 259 GWh were included for the three months ended March 31, 2013 and 2012, respectively.
(h) Includes sales to ComEd under the RFP of 0 GWh and 2,210 GWh for the three months ended March 31, 2013 and 2012, respectively.

The following table presents electric revenue net of purchased power and fuel expense per MWh of electricity sold during the three months ended March 31, 2013 as compared to the three months ended March 31, 2012.

$/MWh	Three Months Ended March 31, 2013	Three Months Ended March 31, 2012(a)	% Change
Mid-Atlantic(b)	$44.04	$ 46.86	(6.0)%
Midwest(c)	28.08	31.40	(10.6)%
New England	7.63	19.61	(61.1)%
New York	(6.27)	8.56	n.m.
ERCOT	20.54	9.26	121.9%
Other Regions(d)	7.61	5.41	40.6%
Electric revenue net of purchased power and fuel expense per MWh(e)(f)	27.23	32.57	(16.4)%

(a) Includes financial results for Constellation beginning on March 12, 2012, the date the merger was completed.
(b) Includes sales to PECO of $141 (1,921 GWh) and $111 million (1,629 GWh) for the three months ended March 31, 2013 and 2012, respectively. Sales to BGE of $113 million (1,535 GWh) and $19 million (259 GWh) were included for the three months ended March 31, 2013 and 2012, respectively. Excludes compensation under the reliability-must-run rate schedule and the financial results of Brandon Shores, H.A. Wagner, and C.P. Crane, the generating facilities divested in the fourth quarter of 2012 as a result of the merger.
(c) Includes sales to ComEd of $0 million (0 GWh) and $82 million (2,210 GWh) and settlements of the ComEd swap of $145 million and $165 million for the three months ended March 31, 2013 and 2012, respectively.
(d) Other Regions includes South, West and Canada, which are not considered individually significant.
(e) Revenue net of purchased power and fuel expense per MWh represents the average margin per MWh of electricity sold during the three months ended March 31, 2013 and 2012 and excludes the mark-to-market impact of Generation’s economic hedging activities.
(f) Excludes retail gas activity, proprietary trading portfolio activity, compensation under the reliability-must-run rate schedule and fuel sales. Also excludes results from energy efficiency, energy management and demand response, upstream natural gas and the design and construction of customer sited solar facilities. In addition, excludes the financial results of Brandon Shores, H.A. Wagner, and C.P. Crane, the generating facilities divested in the fourth quarter of 2012 as a result of the Exelon and Constellation merger. Also excludes amortization of intangible assets relating to commodity contracts recorded at fair value at the merger date of $174 million and $122 million, for the three months ended March 31, 2013 and 2012, respectively.

Mid-Atlantic.

Three Months Ended March 31, 2013 Compared to Three Months Ended March 31, 2012. The $74 million increase in revenue net of purchased power and fuel expense in the Mid-Atlantic was primarily due to the addition of Constellation, higher nuclear volume and capacity revenue, partially offset by increased nuclear fuel costs.

Midwest

Three Months Ended March 31, 2013 Compared to Three Months Ended March 31, 2012. The $100 million decrease in revenue net of purchased power and fuel expense in the Midwest was primarily due to lower capacity revenues and increased nuclear fuels costs.

New England

Three Months Ended March 31, 2013 Compared to Three Months Ended March 31, 2012. The $9 million decrease in revenue net of purchased power and fuel expense in New England was due to increased power and fuel costs, resulting in lower margins on load.

New York

Three Months Ended March 31, 2013 Compared to Three Months Ended March 31, 2012. The $30 million decrease in revenue net of purchased power and fuel expense in New York was due primarily to the addition of Constellation.

ERCOT

Three Months Ended March 31, 2013 Compared to Three Months Ended March 31, 2012. The $67 million increase in revenue net of purchased power and fuel expense in ERCOT was primarily a result of the addition of Constellation.

Other Regions

Three Months Ended March 31, 2013 Compared to Three Months Ended March 31, 2012. The $31 million increase in revenue net of purchased power and fuel expense in Other Regions was primarily as a result of the addition of Constellation.

Mark-to-market

Three Months Ended March 31, 2013 Compared to Three Months Ended March 31, 2012. Generation is exposed to market risks associated with changes in commodity prices and enters into economic hedges to mitigate exposure to these fluctuations. Mark-to-market losses on economic hedging activities were $403 million for the three months ended March 31, 2013 compared to gains of $60 million for the three months ended March 31, 2012. See Notes 8 and 9 of the Combined Notes to Consolidated Financial Statements for information on gains and losses associated with mark-to-market derivatives.

Other

Three Months Ended March 31, 2013 Compared to Three Months Ended March 31, 2012. The $82 million increase in other revenue net of purchased power and fuel was primarily due to the addition of Constellation which includes wholesale and retail gas, energy efficiency, energy management and demand response, upstream natural gas and the design and construction of renewable energy facilities. In addition, other revenue net of purchased power and fuel for 2012 includes the results of Brandon Shores, H.A. Wagner and C.P. Crane, the generating facilities divested in the fourth quarter 2012 as a result of the Exelon and Constellation merger. This increase was partially offset by a decrease in the compensation under the reliability-must-run rate schedule, in addition to amortization of the acquired energy contracts recorded at fair value at the merger date. See Note 4 of the Combined Notes to Consolidated Financial Statements for information regarding contract intangibles.

Nuclear Fleet Capacity Factor and Production Costs. The following table presents nuclear fleet operating data for the three months ended March 31, 2013 as compared to 2012, for the Exelon-operated plants. The nuclear fleet capacity factor presented in the table is defined as the ratio of the actual output of a plant over a period of time to its output if the plant had operated at full average annual mean capacity for that time period. Nuclear fleet production cost is defined as the costs to produce one MWh of energy, including fuel, materials, labor, contracting and other miscellaneous costs, but excludes depreciation and certain other non-production related overhead costs. Generation considers capacity factor and production costs useful measures to analyze the nuclear fleet performance between periods. Generation has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, these measures are not a presentation defined under GAAP and may not be comparable to other companies' presentations or be more useful than the GAAP information provided elsewhere in this report.

	Three Months Ended March 31,	
	2013	**2012**
Nuclear fleet capacity factor(a)	96.4%	93.6%
Nuclear fleet production cost per MWh(a)	$19.67	$20.06

(a) Reflects ownership percentage of stations operated by Exelon. Excludes Salem, which is operated by PSEG Nuclear, LLC, and Exelon's ownership in jointly owned generating plants through equity method investments (e.g. CENG).

The nuclear fleet capacity factor, which excludes Salem, increased primarily due to a lower number of unplanned outage days and planned refueling outage days, which resulted in higher generation, during the three months ended March 31, 2013 compared to the same period in 2012. For the three months ended March 31, 2013 and 2012, unplanned outage days totaled 6 and 16, respectively, and planned refueling outage days totaled 49 and 67, respectively. An increase in nuclear generation resulted in a lower production cost per MWh for the three months ended March 31, 2013 as compared to the same period in 2012.

Operating and Maintenance

The change in operating and maintenance expense for the three months ended March 31, 2013 compared to the same period in 2012, consisted of the following:

	Increase (Decrease)
FERC settlement(a)	$ (195)
Constellation merger and integration costs	(53)
Nuclear refueling outage costs, including the co-owned Salem plant(b)	(27)
Labor, other benefits, contracting and materials	158
Corporate allocations(c)	37
Other	13
Decrease in operating and maintenance expense	$ (67)

(a) Reflects costs incurred as part of a March 2012 settlement with the FERC to resolve a dispute related to Constellation's prior period hedging and risk management transactions.
(b) Reflects the impact of decreased planned refueling outage days in 2013.
(c) Reflects the impact of an increased share of corporate allocated costs due to the merger.

Depreciation and Amortization

The increase in depreciation and amortization expense for the three months ended March 31, 2013 compared to the same period in 2012 was primarily due to higher plant balances due to the addition of Constellation facilities, capital additions and upgrades to existing facilities.

Taxes Other Than Income

The increase in taxes other than income for the three months ended March 31, 2013 compared to the same period in 2012 was primarily due to the addition of Constellation's financial results in March 2012.

Equity in Losses of Unconsolidated Affiliates

Equity in losses of unconsolidated affiliates decreased by $13 million primarily due to net income generated from Exelon's equity investment in CENG in 2013 compared to the loss recorded by CENG from March 12, 2012 through March 31, 2012. The loss recorded for this period in 2012 was due to planned nuclear fueling outage days. Partially offsetting this improvement in CENG's earnings, Generation's results were also affected by increased amortization of the basis difference in CENG recorded at fair value at the merger.

Interest Expense

The increase in interest expense for the three months ended March 31, 2013 compared to the same period in 2012 was primarily due to the long-term debt assumed in connection with the merger and an increase in debt issued at Generation in June 2012.

Other, Net

Other, net primarily reflects the change in the gain/loss position for the three months ended March 31, 2013 compared to the same period in 2012 related to the NDT funds of its Non-Regulatory Agreement Units as described in the table below. Other, net also reflects $43 million of income in 2013 compared to $64 million of income in 2012 related to the contractual elimination of income tax expenses in March 31, 2013 and 2012, respectively, associated with the NDT funds of the Regulatory Agreement Units.

The following table provides unrealized and realized gains on the NDT funds of the Non-Regulatory Agreement Units recognized in Other, net for the three months ended March 31, 2013 and 2012:

	Three Months Ended March 31, 2013	Three Months Ended March 31, 2012
Net unrealized gains on decommissioning trust funds	$ 64	$ 65
Net realized gains on sale of decommissioning trust funds	2	37

Effective Income Tax Rate

The effective income tax rate was 5.6% for the three months ended March 31, 2013 compared to 58.1% for the same period during 2012. See Note 11 — of the Combined Notes to Consolidated Financial Statements for further discussion of the change in effective income tax rate.

Results of Operations — ComEd

	Three Months Ended Ended March 31, 2013	Three Months Ended Ended March 31, 2012	Favorable (Unfavorable) Variance
Operating revenues	$ 1,160	$ 1,388	$ (228)
Purchased power expense	382	620	238
Revenue net of purchased power expense(a)	778	768	10
Other operating expenses			
Operating and maintenance	328	318	(10)
Depreciation and amortization	167	149	(18)
Taxes other than income	74	75	1
Total other operating expenses	569	542	(27)
Operating income	209	226	(17)
Other income and deductions			
Interest expense, net	(353)	(82)	(271)
Other, net	5	4	1
Total other income and deductions	(348)	(78)	(270)
Income (loss) before income taxes	(139)	148	(287)
Income taxes	(58)	61	119
Net income (loss)	$ (81)	$ 87	$ (168)

(a) ComEd evaluates its operating performance using the measure of revenue net of purchased power expense. ComEd believes that revenue net of purchased power expense is a useful measurement because it provides information that can be used to evaluate its operational performance. In general, ComEd only earns margin based on the delivery and transmission of electricity. ComEd has included its discussion of revenue net of purchased power expense below as a complement to the financial information provided in accordance with GAAP. However, revenue net of purchased power expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

Net Income (Loss)

ComEd's net loss for the three months ended March 31, 2013, was primarily due to the remeasurement of Exelon's like-kind exchange tax position in the first quarter of 2013. See Note 11 of the Combined Notes to Consolidated Financial Statements for additional information

Operating Revenues Net of Purchased Power Expense

There are certain drivers of revenue that are fully offset by their impact on purchased power expense, such as commodity procurement costs and customer choice programs. ComEd is permitted to recover its electricity procurement costs from retail customers without mark-up. Therefore, fluctuations in electricity procurement costs have no impact on electric revenues net of purchased power expense. See Note 5 of the Combined Notes to Consolidated Financial Statements for additional information on ComEd's electricity procurement process.

Electric revenues and purchased power expense are affected by fluctuations in customers' purchases from competitive retail electric suppliers. All ComEd customers have the ability to purchase electricity from an alternative retail electric supplier. The customer choice of retail electric supplier does not impact the volume of deliveries, but affects revenue collected from customers related to supplied energy services. The number of retail customers purchasing electricity from alternative retail electric suppliers was 2,589,931 and 492,079 at March 31, 2013, and 2012, respectively, representing 67% and 13% of total retail customers, respectively. Retail energy purchased from alternative retail electric suppliers represented 75% and 60% of ComEd's retail kWh sales at March 31, 2013, and 2012, respectively. During 2012, The City of Chicago and approximately 240 Illinois municipalities approved referenda regarding electric supply aggregation. This approval allowed municipal officials to identify and sign contracts with alternative retail electric suppliers. With few exceptions, approximately 170 municipalities have identified and switched to alternative retail electric suppliers by the end of December 31, 2012. City of Chicago customers switched to alternative retail electric suppliers the first quarter of 2013. All or some of the other 70 municipalities and townships are also expected to switch during the first half of 2013. As contracts with new retail electric suppliers take effect, ComEd expects the percentage of energy purchased from retail electric suppliers to continue to increase. It is anticipated that by the end of the second quarter 2013 approximately 71% of retail customers and 81% of energy sales in the ComEd region will be supplied by alternative retail electric suppliers.

The changes in ComEd's electric revenues net of purchased power expense for the three months ended March 31, 2013, compared to the same period in 2012 consisted of the following:

	Increase (Decrease)
Weather delivery	$ 18
Electric distribution revenues	12
Regulatory required programs cost recovery	3
Volume delivery	(4)
Uncollectible accounts recovery, net	(14)
Other	(5)
Total increase	$ 10

Weather delivery

The demand for electricity is affected by weather conditions. Very warm weather in summer months and very cold weather in other months are referred to as "favorable weather conditions" because these weather conditions result in increased customer usage and delivery of electricity. Conversely, mild weather reduces demand. The favorable weather conditions for the three months ended March 31, 2013, resulted in an increase in revenues net of purchased power expense.

Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 30-year period in ComEd's service territory. The changes in heating and cooling degree days in ComEd's service territory for the three months ended March 31, 2013, and 2012, consisted of the following:

				% Change	
	2013	**2012**	**Normal**	**From 2012**	**From Normal**
Heating Degree-Days	3,259	2,384	3,164	36.7%	3.0%
Cooling Degree-Days	—	39	—	n/a	n/a

Electric distribution revenues

EIMA provides for a performance-based formula rate tariff. The legislation provides for an annual reconciliation of the revenue requirement in effect to the actual costs that the ICC determines are prudently and reasonably incurred in a given year. During the three months ended March 31, 2013, ComEd recorded a $50 million increase in revenues associated with the first quarter of the 2013 reconciliation. This increase in revenue for the three months ended March 31, 2013, as compared to the same period in 2012 was partially offset by a $28 million net reduction to revenues associated with the 2012 and 2011 reconciliations. The net increase in revenues associated with the 2013-2011 reconciliations were also partially offset by a decrease in ComEd's annual electric distribution revenue requirement under EIMA as compared to the revenue requirement permitted in the 2010 Rate Case. See Note 5 of the Combined Notes to Consolidated Financial Statements for additional information.

Regulatory required programs cost recovery

Revenues related to regulatory required programs are the recoveries from customers for costs of various legislative and/or regulatory programs on a full and current basis through approved regulated rates. Programs include ComEd's energy efficiency and demand response and purchased power administrative costs. An equal and offsetting amount has been reflected in operating and maintenance expense during the periods presented. Refer to the operating and maintenance expense discussion below for additional information on included programs.

Transmission

ComEd's transmission rates are 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. Transmission revenues net of purchased power expense vary from year to year based upon fluctuations in the underlying costs, investments being recovered and other billing determinants, such as the highest daily peak load from the previous calendar year. See Note 5 of the Combined Notes to Consolidated Financial Statements for additional information.

Volume delivery

Revenues net of purchased power expense decreased as a result of lower delivery volume, exclusive of the effects of weather, reflecting decreased average usage per residential customer for 2013, compared to 2012.

Uncollectible accounts recovery, net

Represents recoveries under ComEd's uncollectible accounts tariff. Refer to the operating and maintenance expense discussion below for additional information on this tariff.

Other

Other revenues were lower during the three months ended March 31, 2013, compared to 2012. Other revenues, which can vary period to period, include rental revenues, revenues related to late payment charges, assistance provided to other utilities through mutual assistance programs, and recoveries of environmental costs associated with MGP sites.

Operating and Maintenance Expense

	Three Months Ended March 31, 2013	Three Months Ended March 31, 2012	Increase
Operating and maintenance expense — baseline	$ 268	$ 261	$ 7
Operating and maintenance expense — regulatory required programs(a)	60	57	3
Total operating and maintenance expense	328	318	10

(a) Operating and maintenance expenses for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in operating revenues.

The changes in operating and maintenance expense for the three months ended March 31, 2013, compared to the same period in 2012, consisted of the following:

	Increase (Decrease)
Baseline	
Labor, other benefits, contracting and materials	$ 16
Pension and non-pension postretirement benefits expense	6
Uncollectible accounts expense—provision(a)	(7)
Uncollectible accounts expense—recovery, net(a)	(7)
Other	(1)
	7
Regulatory required programs	
Energy efficiency and demand response programs	3
	3
Increase in operating and maintenance expense	$ 10

(a) On February 2, 2010, the ICC issued an order adopting ComEd's proposed tariffs filed in accordance with Illinois legislation providing public utilities the ability to recover from or refund to customers the difference between the utility's annual uncollectible accounts expense and amounts collected in rates annually through a rider mechanism starting with 2008 and prospectively.

Depreciation and Amortization

Depreciation and amortization expense increased during the three months ended March 31, 2013, compared to the same period in 2012 primarily due to increased amortization of the regulatory assets.

Taxes Other Than Income

Taxes other than income decreased during the three months ended March 31, 2013, compared to the same period in 2012. Taxes other than income, which can vary period to period, include municipal and state utility taxes, real estate taxes, and payroll taxes.

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Interest Expense, net

The changes in Interest Expense, net for the three months ended March 31, 2013, compared to the same period in 2012, consisted of the following:

	Increase (Decrease)
Interest expense related to uncertain tax positions(a)	$ 277
Interest expense on debt (including financing trusts)	(3)
Other	(3)
Increase in interest expense, net	$ 271

(a) Primarily reflects the remeasurement of Exelon's like-kind exchange tax position in the first quarter of 2013. See Note 11 of the Combined Notes to Consolidated Financial Statements for additional information.

Effective Income Tax Rate

The effective income tax rate was 41.7% for the three months ended March 31, 2013, compared to 41.2% for the same period during 2012. See Note 11 of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

ComEd Electric Operating Statistics and Revenue Detail

Retail Deliveries to customers (in GWhs)	Three Months Ended March 31, 2013	2012	% Change	Weather-Normal % Change
Retail Delivery and Sales(a)				
Residential	6,876	6,406	7.3%	(0.1)%
Small commercial & industrial	7,873	7,916	(0.5)%	(3.2)%
Large commercial & industrial	6,840	6,703	2.0%	(0.4)%
Public authorities & electric railroads	373	325	14.8%	9.7%
Total Retail	21,962	21,350	2.9%	(1.2)%

Number of Electric Customers	As of March 31, 2013	2012
Residential	3,470,659	3,465,669
Small commercial & industrial	366,284	365,525
Large commercial & industrial	2,001	2,013
Public authorities & electric railroads	4,802	4,790
Total	3,843,746	3,837,997

Electric Revenue	Three Months Ended March 31, 2013	2012	% Change
Retail Delivery and Sales(a)			
Residential	$ 584	$ 775	(24.6)%
Small commercial & industrial	308	348	(11.5)%
Large commercial & industrial	102	100	2.0%
Public authorities & electric railroads	12	12	0.0%
Total Retail	1,006	1,235	(18.5)%
Other Revenue(b)	154	153	0.7%
Total Electric Revenues	$ 1,160	$ 1,388	(16.4)%

(a) Reflects delivery volumes and revenues from customers purchasing electricity directly from ComEd and customers purchasing electricity from a competitive electric generation supplier. All customers are assessed charges for delivery. For customers purchasing electricity from ComEd, revenue also reflects the cost of energy and transmission.
(b) Other revenue primarily includes transmission revenue from PJM. Other items include rental revenue, revenues related to late payment charges, assistance provided to other utilities through mutual assistance programs and recoveries of environmental remediation costs associated with MGP site.

Results of Operations — PECO

	Three Months Ended March 31, 2013	Three Months Ended March 31, 2012	Favorable (Unfavorable) Variance
Operating revenues	$ 895	$ 875	$ 20
Purchased power and fuel	406	411	5
Revenue net of purchased power and fuel(a)	489	464	25
Other operating expenses			
Operating and maintenance	188	203	15
Depreciation and amortization	57	53	(4)
Taxes other than income	41	31	(10)
Total other operating expenses	286	287	1
Operating income	203	177	26
Other income and (deductions)			
Interest expense, net	(29)	(31)	2
Other, net	3	2	1
Total other income and (deductions)	(26)	(29)	3
Income before income taxes	177	148	29
Income taxes	55	51	(4)
Net income	122	97	25
Preferred security dividends	1	1	—
Net income on common stock	$ 121	$ 96	$ 25

(a) PECO evaluates its operating performance using the measures of revenue net of purchased power expense for electric sales and revenue net of fuel expense for gas sales. PECO believes revenue net of purchased power expense and revenue net of fuel expense are useful measurements of its performance because they provide information that can be used to evaluate its net revenue from operations. PECO has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, revenue net of purchased power expense and revenue net of fuel expense figures are not a presentation defined under GAAP and may not be comparable to other companies' presentations or more useful than the GAAP information provided elsewhere in this report.

Net Income

The increase in net income was driven primarily by higher operating revenue net of purchased power and fuel expense and a decrease in operating and maintenance expenses, partially offset by higher taxes other than income. The increase in revenue net of purchased power and fuel expense was the result of favorable weather, which was partially offset by the impact of pricing.

Operating Revenues, Purchased Power and Fuel Expense

There are certain drivers to operating revenue that are offset by their impact on purchased power expense and fuel expense, such as commodity procurement costs and customer choice programs. Electric and gas revenues and purchased power and fuel expense are affected by fluctuations in commodity procurement costs. PECO's electric supply and natural gas cost rates charged to customers are subject to adjustments at least quarterly that are designed to recover or refund the difference between the actual cost of electric supply and natural gas and the amount included in rates in accordance with the PAPUC's GSA and PGC, respectively. Therefore, fluctuations in electric supply and natural gas procurement costs have no impact on electric and gas revenue net of purchased power and fuel expense.

Electric and gas revenues and purchased power and fuel expense are also affected by fluctuations in participation in the customer choice program. All PECO customers have the choice to purchase electricity and gas from competitive electric generation and natural gas suppliers, respectively. The customer's choice of suppliers does not impact the volume of deliveries, but affects revenue collected from customers related to supplied electricity and natural gas service. Customer choice program activity has no impact on electric and gas revenue net of purchased power and fuel expense. The number of retail customers purchasing electricity from a competitive electric generation supplier was 517,000 and 416,600 at March 31, 2013 and 2012, respectively. Retail deliveries purchased from competitive electric generation suppliers represented 65% and 64% of PECO's retail kWh sales for the three months ended March 31, 2013 and 2012, respectively. The number of retail customers purchasing natural gas from a competitive natural gas supplier was 57,600 and 34,900 at March 31, 2013 and 2012, respectively. Retail deliveries purchased from competitive natural gas suppliers represented 18% and 13% of PECO's retail mmcf sales for the three months ended March 31, 2013 and 2012, respectively.

The changes in PECO's operating revenues net of purchased power and fuel expense for the three months ended March 31, 2013 compared to the same period in 2012, consisted of the following:

	Increase (Decrease)		
	Electric	Gas	Total
Weather	$ 18	$22	$ 40
Pricing	(8)	(3)	(11)
Regulatory required programs	(2)	—	(2)
Other	(2)	—	(2)
Total increase	$ 6	$19	$ 25

Weather. The demand for electricity and gas is affected by weather conditions. With respect to the electric business, very warm weather in summer months and, with respect to the electric and gas businesses, very cold weather in winter months are referred to as "favorable weather conditions" because these weather conditions result in increased deliveries of electricity and gas. Conversely, mild weather reduces demand. Operating revenues net of purchased power and fuel expense were higher due to the impact of favorable weather conditions during 2013 in PECO's service territory.

Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 30-year period in PECO's service territory. The changes in heating and cooling degree days in PECO's service territory for the three months ended March 31, 2013 compared to the same period in 2012 consisted of the following:

				% Change	
Heating and Cooling Degree-Days	2013	2012	Normal	From 2012	From Normal
Heating Degree-Days	2,440	1,914	2,476	27.5%	(1.5)%
Cooling Degree-Days	—	4	—	n/a%	n/a%

Pricing. The decrease in electric revenues net of purchased power expense as a result of pricing reflected lower effective rates due to increased usage per customer across all customer classes. The decrease in gas revenue net of fuel expense as a result of pricing reflected the refund of the tax cash benefit resulting from the change in PECO's method of accounting for gas distribution repairs in 2012. The refund was reflected on customer bills as a credit beginning January 1, 2013. The impact of the refund is completely offset by regulatory liability amortization recorded in income tax expense. See Note 5 of the Combined Notes to the Consolidated Financial Statements for further information.

Regulatory Required Programs. This represents the change in operating revenues collected under approved riders to recover costs incurred for regulatory programs such as smart meter, energy efficiency and the GSA. The riders are designed to provide full and current cost recovery as well as a return. The costs of these programs are included in operating and maintenance expense, depreciation and amortization expense and income taxes. Refer to the operating and maintenance expense discussion below for additional information on included programs.

Other. The decrease in other electric revenues net of purchased power expense for the three months ended March 31, 2013 compared to the same period in 2012 reflected a decrease in GRT revenue as a result of lower supplied energy service. There is an equal and offsetting decrease in GRT expense included in taxes other than income.

Operating and Maintenance Expense

	Three Months Ended March 31, 2013	Three Months Ended March 31, 2012	Increase (Decrease)
Operating and Maintenance Expense — Baseline	$ 173	$ 184	$ (11)
Operating and Maintenance Expense — Regulatory Required Programs(a)	15	19	(4)
Total Operating and Maintenance Expense	188	203	(15)

(a) Operating and maintenance expenses for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in operating revenues.

The changes in operating and maintenance expense for the three months ended March 31, 2013 compared to the same period in 2012, consisted of the following:

	Increase (Decrease)
Baseline	
Labor, other benefits, contracting and materials	$ (4)
Constellation merger and integration costs	(4)
Pension and non-pension postretirement benefits expense	(3)
	(11)
Regulatory Required Programs	
Energy Efficiency	(4)
	(4)
Decrease in operating and maintenance expense	$ (15)

Depreciation and Amortization

The increase in depreciation and amortization expense for the three months ended March 31, 2013 compared to the same period in 2012 was primarily due ongoing capital expenditures.

Taxes Other Than Income

Taxes other than income increased for the three months ended March 31, 2013 compared to the same period in 2012 primarily due to a favorable sales and use tax reserve adjustment resulting from the completion of the audit of tax years 2005 through 2010 recorded in the first quarter of 2012.

Interest Expense, Net

The decrease in interest expense, net for the three months ended March 31, 2013 compared to the same period in 2012 was primarily due to lower interest expense as a result of refinancing debt retired in 2012 at lower interest rates during the second half of 2012.

Other, Net

Other, net for the three months ended March 31, 2013 remained relatively level compared to the same period in 2012.

Effective Income Tax Rate

PECO's effective income tax rate was 31.1% for the three months ended March 31, 2013 as compared to 34.5% for the same period during 2012. See Note 11 of the Combined Notes to the Consolidated Financial Statements for further discussion of the change in effective income tax rate.

PECO Electric Operating Statistics and Revenue Detail

PECO's electric sales statistics and revenue detail were as follows:

Retail Deliveries to customers (in GWhs)	Three Months Ended March 31, 2013	Three Months Ended March 31, 2012	% Change	Weather-Normal % Change
Retail Deliveries and Sales(a)				
Residential	3,465	3,166	9.4%	0.5%
Small commercial & industrial	2,009	1,951	3.0%	(4.5)%
Large commercial & industrial	3,646	3,637	0.2%	1.5%
Public authorities & electric railroads	255	237	7.6%	7.6%
Total Electric Retail	9,375	8,991	4.3%	—%

Number of Electric Customers	As of March 31, 2013	As of March 31, 2012
Residential	1,423,333	1,420,734
Small commercial & industrial	148,749	148,756
Large commercial & industrial	3,117	3,109
Public authorities & electric railroads	9,657	9,688
Total	1,584,856	1,582,287

Electric Revenue	Three Months Ended March 31, 2013	2012	% Change
Retail Deliveries and Sales(a)			
Residential	$ 395	$ 407	(2.9)%
Small commercial & industrial	106	118	(10.2)%
Large commercial & industrial	59	54	9.3%
Public authorities & electric railroads	8	8	—%
Total Electric Retail	568	587	(3.2)%
Other revenue(b)	55	56	(1.8)%
Total Electric Revenues	$ 623	$ 643	(3.1)%

(a) Reflects delivery volumes and revenues from customers purchasing electricity directly from PECO and customers purchasing electricity directly from a competitive electric generation supplier as all customers are assessed distribution charges. For customers purchasing electricity from PECO, revenue also reflects the cost of energy and transmission.
(b) Other revenue includes transmission revenue from PJM and wholesale electric revenues.

PECO Gas Sales Statistics and Revenue Detail

PECO's gas sales statistics and revenue detail were as follows:

Deliveries to customers (in mmcf)	Three Months Ended March 31, 2013	2012	% Change	Weather-Normal % Change
Retail Deliveries and Sales				
Retail sales(a)	28,438	22,427	26.8%	(0.4)%
Transportation and other	8,883	7,766	14.4%	10.9%
Total Gas Deliveries	37,321	30,193	23.6%	2.0%

Number of Gas Customers	As of March 31, 2013	2012
Residential	455,979	452,800
Commercial & industrial	41,972	41,577
Total Retail	497,951	494,377
Transportation	904	888
Total	498,855	495,265

Gas revenue	Three Months Ended March 31, 2013	2012	% Change
Retail sales	$ 260	$ 222	17.1%
Transportation and other	12	10	20.0%
Total Gas Revenue	$ 272	$ 232	17.2%

(a) Reflects delivery volumes and revenues from customers purchasing natural gas directly from PECO and customers purchasing natural gas directly from a competitive natural gas supplier as all customers are assessed distribution charges. The cost of natural gas is charged to customers purchasing natural gas from PECO.

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Results of Operations — BGE

	Three Months Ended March 31, 2013	Three Months Ended March 31, 2012	Favorable (Unfavorable) Variance
Operating revenues	$ 880	$ 697	$ 183
Purchased power and fuel expense	426	385	(41)
Revenue net of purchased power and fuel expense(a)	454	312	142
Other operating expenses			
Operating and maintenance	143	196	53
Depreciation and amortization	93	79	(14)
Taxes other than income	55	48	(7)
Total other operating expenses	291	323	32
Operating income (loss)	163	(11)	174
Other income and (deductions)			
Interest expense, net	(33)	(41)	8
Other, net	5	6	(1)
Total other income and (deductions)	(28)	(35)	7
Income (Loss) before income taxes	135	(46)	181
Income taxes	55	(16)	(71)
Net income (loss)	80	(30)	110
Preference stock dividends	3	3	—
Net income (loss) on common stock	$ 77	$ (33)	$ 110

(a) BGE evaluates its operating performance using the measures of revenue net of purchased power expense for electric sales and revenue net of fuel expense for gas sales. BGE believes revenue net of purchased power and fuel expense are useful measurements of its performance because they provide information that can be used to evaluate its net revenue from operations. BGE has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, revenue net of purchased power and fuel expense figures are not a presentation defined under GAAP and may not be comparable to other companies' presentations or more useful than the GAAP information provided elsewhere in this report.

Net Income (Loss)

The increase in net income was driven primarily by decreased operating revenue net of purchased power and fuel expense in 2012 related to the accrual of the residential customer rate credit provided as a condition of the MDPSC's approval of Exelon's merger with Constellation. The increase in net income was also driven by increased operating and maintenance expenses in 2012, primarily related to BGE's accrual of its portion of the charitable contributions to be provided as a condition of the MDPSC's approval of the merger.

Operating Revenues, Purchased Power and Fuel Expense

There are certain drivers to operating revenue that are offset by their impact on purchased power expense and fuel expense, such as commodity procurement costs and programs allowing customers to select a competitive electric or natural gas supplier. Electric and gas revenues and purchased power and fuel expense are affected by fluctuations in commodity procurement costs. BGE's electric and natural gas rates charged to customers are subject to periodic adjustments that are designed to recover or refund the difference between the actual cost of purchased electric power and purchased natural gas and the amount included in rates in accordance with the MDPSC's market-based SOS and gas commodity programs, respectively.

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The number of customers electing to select a competitive electric supplier affects electric SOS revenues and purchased power expense. The number of customers electing to select a competitive natural gas supplier affects gas cost adjustment revenues and purchased natural gas expense. All BGE customers have the choice to purchase energy from a competitive electric supplier. This customer choice of electric suppliers does not impact the volume of deliveries, but affects revenue collected from customers related to SOS. The number of retail customers purchasing electricity from a competitive electric supplier was 375,400 and 320,800 at March 31, 2013 and 2012, respectively, representing 30% and 26% of total retail customers, respectively. Retail deliveries purchased from competitive electric suppliers represented 59% of BGE's retail kWh sales for the three months ended March 31, 2013 and 2012. The number of retail customers purchasing natural gas from a competitive natural gas supplier was 152,800 and 118,200 at March 31, 2013 and 2012, respectively, representing 23% and 18% of total retail customers, respectively. Retail deliveries purchased from competitive natural gas suppliers represented 47% and 49% of BGE's retail mmcf sales for the three months ended March 31, 2013 and 2012, respectively.

The changes in BGE's operating revenues net of purchased power and fuel expense for the three months ended March 31, 2013 compared to the same period in 2012, consisted of the following:

	Increase (Decrease)		
	Electric	**Gas**	**Total**
Residential customer rate credit(a)	$ 82	$31	$113
Regulatory required programs	11	4	15
Distribution rates increase	6	3	9
Other	5	—	5
Total increase	$ 104	$38	$142

(a) In accordance with the MDPSC order approving Exelon's merger with Constellation, the residential customer rate credit is not recoverable from BGE's customers. Exelon made a $66 million equity contribution to BGE in the second quarter of 2012 to fund the after-tax amount of the rate credit as directed in the MDPSC order approving the merger transaction.

Revenue Decoupling. The demand for electricity and gas is affected by weather and usage conditions. The MDPSC has allowed BGE to record a monthly adjustment to its electric and gas distribution revenues from all residential customers, commercial electric customers, the majority of large industrial electric customers, and all firm service gas customers to eliminate the effect of abnormal weather and usage patterns per customer on BGE's electric and gas distribution volumes, thereby recovering a specified dollar amount of distribution revenues per customer, by customer class, regardless of changes in consumption levels. This means BGE recognizes revenues at MDPSC-approved levels per customer, regardless of what actual distribution volumes were for a billing period. Therefore, while these revenues are affected by customer growth, they will not be affected by actual weather or usage conditions. BGE bills or credits affected customers in subsequent months for the difference between approved revenue levels under revenue decoupling and actual customer billings.

Volume. Heating degree days are quantitative indices that reflect the demand for energy needed to heat a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 30-year period in BGE's service territory. The changes in heating degree days in BGE's service territory for the three months ended March 31, 2013 compared to the same period in 2012 consisted of the following:

				% Change	
Heating Degree-Days	**2013**	**2012**	**Normal**	**From 2012**	**From Normal**
Heating Degree-Days	2,451	1,874	2,384	30.8 %	2.8%
Cooling Degree-Days	1	10	—	(90.0)%	n.m.

Residential Customer Rate Credit. The residential customer rate credit provided in 2012 as a result of the MDPSC's order approving Exelon's merger with Constellation decreased operating revenues net of purchased power and fuel expense compared to the same period in 2013.

Regulatory Required Programs. This represents the change in revenues collected under approved riders to recover costs incurred for the energy efficiency and demand response programs as well as administrative and commercial and industrial customer bad debt costs for SOS. The riders are designed to provide full recovery, as well as a return in certain instances. The costs of these programs are included in operating and maintenance expense, depreciation and amortization expense and taxes other than income taxes. The increase in revenues during the three months ended March 31, 2013 compared to the same period in 2012 was primarily due to the recovery of higher energy efficiency program costs.

Distribution Rates Increase. The MDPSC issued an order approving an increase in BGE's annual electric and gas distribution revenue requirement. The increase in electric and gas distribution rates became effective for services rendered on or after February 23, 2013, resulting in higher revenues for the three months ended March 31, 2013 compared to the same period in 2012. See Note 5 of the Combined Notes to the Consolidated Financial Statements for additional information.

Other. Other revenues increased during the three months ended March 31, 2013 compared to the same period in 2012. Other revenues, which can vary from period to period, include off-system revenues and other miscellaneous revenues such as late payment charge revenues and all other base distribution revenues, which increased due to higher volumes and customer mix.

Operating and Maintenance Expense

	Three Months Ended March 31, 2013	Three Months Ended March 31, 2012	Increase (Decrease)
Operating and Maintenance Expense — Baseline	$ 143	$ 196	$ (53)
Operating and Maintenance Expense — Regulatory Required Programs(a)	—	—	—
Total Operating and Maintenance Expense	143	196	(53)

(a) Operating and maintenance expenses for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in operating revenues.

The changes in baseline operating and maintenance expense for the three months ended March 31, 2013 compared to the same period in 2012, consisted of the following:

	Increase (Decrease)
Baseline	
Charitable contributions accrual(a)	$ (28)
Labor, other benefits, contracting and materials	(11)
Merger transaction costs(b)	(8)
Storm-related costs	8
Other	(14)
	(53)
Regulatory Required Programs	
SOS	—
Decrease in operating and maintenance expense	$ (53)

(a) In accordance with the MDPSC order approving Exelon's merger with Constellation, the charitable contribution accrual is not recoverable from BGE's customers.

(b) BGE established a regulatory asset of $6 million at March 31, 2013 for certain 2012 other merger integration costs as part of the 2013 electric and gas distribution rate case order.

Depreciation and Amortization

The increase in depreciation and amortization expense for the three months ended March 31, 2013 compared to the same period in 2012 was primarily due to increased amortization expense related to energy efficiency and demand response programs, which is fully offset in revenues, and higher plant balances.

Taxes Other Than Income

Taxes other than income increased for the three months ended March 31, 2013 compared to the same period in 2012 primarily due to increased gross receipts tax as a result of higher revenues.

Interest Expense, Net

The decrease in interest expense, net for the three months ended March 31, 2013 compared to the same period in 2012 was primarily due to interest recorded in 2012 on prior year tax liabilities and more favorable interest rates in 2013 on long-term debt balances.

Effective Income Tax Rate

BGE's effective income tax rate was 40.7% for the three months ended March 31, 2013 as compared to 34.8% for the same period during 2012. See Note 11 of the Combined Notes to Consolidated Financial Statements for further discussion of the change in effective income tax rate.

BGE Electric Operating Statistics and Revenue Detail

BGE's electric sales statistics and revenue detail were as follows:

	Three Months Ended March 31,			
Retail Deliveries to customers (in GWhs)	**2013**	**2012**	**% Change**	**Weather-Normal % Change**
Retail Deliveries and Sales(a)				
Residential	3,536	3,201	10.5 %	n.m.
Small commercial & industrial	776	729	6.4 %	n.m.
Large commercial & industrial	3,554	3,639	(2.3)%	n.m.
Public authorities & electric railroads	82	88	(6.8)%	n.m.
Total Electric Retail	7,948	7,657	3.8%	n.m.

	As of March 31,	
Number of Electric Customers	**2013**	**2012**
Residential	1,118,824	1,116,201
Small commercial & industrial	113,051	113,177
Large commercial & industrial	11,589	11,492
Public authorities & electric railroads	318	298
Total	1,243,782	1,241,168

Electric Revenue	Three Months Ended March 31, 2013	2012	% Change
Retail Deliveries and Sales(a)			
Residential	$ 365	$ 265	37.7%
Small commercial & industrial	64	63	1.6%
Large commercial & industrial	105	96	9.4%
Public authorities & electric railroads	8	7	14.3%
Total Electric Retail	542	431	25.8%
Other revenue	63	43	46.5%
Total Electric Revenues	$ 605	$ 474	27.6%

(a) Reflects delivery volumes and revenues from customers purchasing electricity directly from BGE and customers electing to receive electric generation service from a competitive electric generation supplier as all customers are assessed distribution charges. For customers purchasing electricity from BGE, revenue also reflects the cost of energy and transmission.

BGE Gas Sales Statistics and Revenue Detail

BGE's gas sales statistics and revenue detail were as follows:

Deliveries to customers (in mmcf)	Three Months Ended March 31, 2013	2012	% Change	Weather-Normal % Change
Retail sales	40,261	33,931	18.7%	n.m.
Transportation and other	5,651	5,440	3.9%	n.m.
Total Gas Deliveries	45,912	39,371	16.6%	n.m.

Number of Gas Customers	As of March 31, 2013	2012
Residential	612,065	610,612
Commercial & industrial	44,308	44,170
Total	656,373	654,782

Gas revenue	Three Months Ended March 31, 2013	2012	% Change
Retail sales	$ 246	$ 188	30.9%
Transportation and other(b)	29	19	52.6%
Total Gas Revenue	$ 275	$ 207	32.9%

(b) Transportation and other gas revenue includes off-system revenue of 5,651 mmcfs ($24 million) and 5,440 mmcfs ($17 million) for the three months ended March 31, 2013 and 2012.

Liquidity and Capital Resources

Exelon and Generation prior year activity presented below includes the activity of Constellation, and BGE in the case of Exelon, from the merger effective date of March 12, 2012 through March 31, 2012. BGE prior year activity presented below includes its activity for the three months ended March 31, 2012.

The Registrants' operating and capital expenditures requirements are provided by internally generated cash flows from operations as well as funds from external sources in the capital markets and through bank borrowings.

The Registrants' businesses are capital intensive and require considerable capital resources. Each Registrant's access to external financing on reasonable terms depends on its credit ratings and current overall capital market business conditions, including that of the utility industry in general. If these conditions deteriorate to the extent that the Registrants no longer have access to the capital markets at reasonable terms, Exelon, Generation, ComEd, PECO and BGE have access to unsecured revolving credit facilities with aggregate bank commitments of $0.5 billion, $5.3 billion, $1.0 billion, $0.6 billion and $0.6 billion, respectively. The Registrants' revolving credit facilities expire between 2017 and 2018. In addition, Generation has $0.4 billion in bilateral facilities with banks. The bilateral facilities at Generation have expirations in January 2015, December 2015 and March 2016. The Registrants utilize their credit facilities to support their commercial paper programs, provide for other short-term borrowings and issue letters of credit. See the "Credit Matters" section below for further discussion. The Registrants expect cash flows to be sufficient to meet operating expenses, financing costs and capital expenditure requirements.

The Registrants primarily use their capital resources, including cash, to fund capital requirements, including construction expenditures, retire debt, pay dividends, fund pension and other postretirement benefit obligations and invest in new and existing ventures. The Registrants spend a significant amount of cash on capital improvements and construction projects that have a long-term return on investment. Additionally, ComEd, PECO and BGE operate in rate-regulated environments in which the amount of new investment recovery may be delayed or limited and where such recovery takes place over an extended period of time. See Note 10 of the Combined Notes to Consolidated Financial Statements for further discussion of the Registrants' debt and credit agreements.

Cash Flows from Operating Activities

General

Generation's cash flows from operating activities primarily result from the sale of electric energy and energy-related products and services to customers. Generation's future cash flows from operating activities may be affected by future demand for and market prices of energy and its ability to continue to produce and supply power at competitive costs as well as to obtain collections from customers.

ComEd's, PECO's and BGE's cash flows from operating activities primarily result from the transmission and distribution of electricity and, in the case of PECO and BGE, gas distribution services. ComEd's, PECO's and BGE's distribution services are provided to an established and diverse base of retail customers. ComEd's, PECO's and BGE's future cash flows may be affected by the economy, weather conditions, future legislative initiatives, future regulatory proceedings with respect to their rates or operations, competitive suppliers, and their ability to achieve operating cost reductions.

See Notes 5 and 17 of the Combined Notes to Consolidated Financial Statements for further discussion of regulatory and legal proceedings and proposed legislation.

Pension and Other Postretirement Benefits

Management considers various factors when making pension funding decisions, including actuarially determined minimum contribution requirements under ERISA, contributions required to avoid benefit restrictions and at-risk status as defined by the Pension Protection Act of 2006, management of the pension obligation and regulatory implications. On July 6, 2012, President Obama signed into law the Moving Ahead for Progress in the Twenty-first Century Act, which contains a pension funding provision that results in lower pension contributions in the near term while increasing the premiums pension plans pay to the Pension Benefit Guaranty Corporation. Certain provisions of the law were applied in 2012 while others take effect in 2013. The estimated impacts of the law are reflected in the projected pension contributions below.

Exelon expects to contribute $255 million to its qualified pension plans in 2013, of which Generation, ComEd, PECO and BGE will contribute $113 million, $116 million, $11 million and $0 million, respectively.

Unlike the qualified pension plans, Exelon's non-qualified pension plans are not funded. Exelon expects to make non-qualified pension plan benefit payments of $79 million in 2013, of which Generation, ComEd, PECO, and BGE will make payments of $6 million, $1 million, $1 million, and $2 million, respectively.

To the extent interest rates continue to decline or the pension plans do not earn the expected asset return rates, annual pension contribution requirements in future years could increase and such increases could be significant, especially in years 2015 and beyond. Additionally, the contribution could change if Exelon changes its pension funding strategy.

Unlike qualified pension plans, other postretirement plans are not subject to regulatory minimum contribution requirements. Exelon's management considers several factors in determining the level of contributions to its other postretirement benefit plans, including levels of benefit claims paid and regulatory implications (amounts deemed prudent to meet regulator expectations and best assure continued recovery). In 2013, Exelon anticipates funding its other postretirement benefit plans based on the funding considerations discussed above, with the exception of those plans previously sponsored by Constellation and AmerGen, which remain unfunded. Exelon expects to make other postretirement benefit plan contributions, including benefit payments related to unfunded plans, of approximately $292 million in 2013, of which Generation, ComEd, PECO and BGE expect to contribute $117 million, $114 million, $22 million and $18 million, respectively.

Tax Matters

The Registrants' future cash flows from operating activities may be affected by the following tax matters:

- Exelon expects to receive a Federal refund of approximately $310 million between 2013 and 2014 which will be paid to (from) ComEd, PECO, BGE and Generation of approximately $320 million, $25 million, $20 million, and ($15) million, respectively.
- Given the current economic environment, state and local governments are facing increasing financial challenges, which may increase the risk of additional income tax levies, property taxes and other taxes.

The following table provides a summary of the major items affecting Exelon's cash flows from operations for the three months ended March 31, 2013 and 2012:

	Three Months Ended March 31, 2013	Three Months Ended March 31, 2012	Variance
Net income	$ 1	$ 200	$ (199)
Add (subtract):			
Non-cash operating activities(a)	960	1,231	(271)
Pension and other postretirement benefit contributions	(267)	(55)	(212)
Income taxes	632	178	454
Changes in working capital and other noncurrent assets and liabilities(b)	(278)	(800)	522
Option premiums paid, net	(3)	(100)	97
Counterparty collateral received (posted), net	(186)	340	(526)
Net cash flows provided by operations	$ 859	$ 994	$ (135)

(a) Represents depreciation, amortization and accretion, impairment of long-lived assets, mark-to-market gains and losses on derivative transactions, deferred income taxes, provision for uncollectible accounts, pension and other postretirement benefit expense, equity in losses of unconsolidated affiliates and investments, decommissioning-related items, stock compensation expense and other non-cash charges.

(b) Changes in working capital and other noncurrent assets and liabilities exclude the changes in commercial paper, income taxes and the current portion of long-term debt.

Cash flows provided by operations for the three months ended March 31, 2013 and 2012 by Registrant were as follows:

	Three Months Ended March 31, 2013	2012
Exelon	$ 859	$ 994
Generation	506	795
ComEd	58	291
PECO	195	172
BGE	185	258

Changes in Exelon's, Generation's, ComEd's, PECO's and BGE's cash flows from operations were generally consistent with changes in each Registrant's respective results of operations, as adjusted by changes in working capital in the normal course of business. In addition, significant operating cash flow impacts for the Registrants for the three months ended March 31, 2013 and 2012 were as follows:

Generation

- During the three months ended March 31, 2013 and 2012, Generation had net (payments) receipts of counterparty collateral of $(203) million and $348 million, respectively. Net (payments) receipts during the three months ended March 31, 2013 and 2012 were primarily due to market conditions that resulted in changes to Generation's net mark-to-market position. Depending upon whether Generation is in a net mark-to-market liability or asset position, collateral may be required to be posted with or collected from its counterparties. This collateral may be in various forms, such as cash, which may be obtained through the issuance of commercial paper, or letters of credit.
- During the three months ended March 31, 2013 and 2012, Generation had net payments of approximately $(3) million and $(100) million, respectively, related to purchases and sales of options. The level of option activity in a given period may vary due to several factors, including changes in market conditions as well as changes in hedging strategy.

ComEd

- During the three months ended March 31, 2013 and 2012, ComEd's net payables to Generation for energy purchases related to its supplier forward contract, ICC-approved RFP contracts and financial swap contract settlements (decreased) increased by $(11) million and $6 million, respectively. During the three months ended March 31, 2013 and 2012, ComEd's payables to other energy suppliers for energy purchases increased (decreased) by $24 million and $(16) million, respectively.
- During the three months ended March 31, 2013 and 2012, ComEd received $17 million and posted $8 million, respectively, of incremental cash collateral from PJM. ComEd's collateral posted with PJM has decreased due to lower PJM billings resulting from lower load being served by ComEd due to increased switching activity primarily driven by municipal aggregation. As of March 31, 2013 and 2012, ComEd had $36 million and $98 million, respectively, of collateral posted with PJM.

PECO

- During the three months ended March 31, 2013 and 2012, PECO's payables to Generation for energy purchases (decreased) increased by $(56) million and $8 million, respectively, and payables to other electric and gas suppliers for energy purchases increased (decreased) by $12 million and $(30) million, respectively.

BGE

- During the three months ended March 31, 2013 and 2012, BGE's payables to Generation for energy purchases increased by $5 million and increased by $3 million, respectively, and payables to other electric and gas suppliers for energy purchases increased by $17 million and $1 million, respectively.

Cash Flows from Investing Activities

Cash flows used in investing activities for the three months ended March 31, 2013 and 2012 by Registrant were as follows:

	Three Months Ended March 31,	
	2013	2012
Exelon	$(1,471)	$ (640)
Generation	(865)	(471)
ComEd	(336)	(280)
PECO	(171)	(130)
BGE	(154)	(146)

Capital expenditures by Registrant for the three months ended March 31, 2013 and 2012 and projected amounts for the full year 2013 are as follows:

	Projected Full Year 2013(e)	Three Months Ended March 31,	
		2013	2012
Exelon	$ 5,400	$ 1,447	$ 1,496
Generation(a)	2,725	841	1,055
ComEd(b)	1,400	346	291
PECO	575	122	96
BGE(d)	675	134	130
Other(c)	25	4	20

(a) Includes nuclear fuel.
(b) The projected capital expenditures include approximately $227 million of expected incremental spending. Pursuant to EIMA, ComEd has committed to invest approximately $2.6 billion over a ten year period to modernize and storm-harden its distribution system and to implement smart grid technology. ComEd filed an updated investment plan with the ICC on April 1, 2013. ComEd's projected expenditures do not reflect the projected impact of Senate Bill 9. See "Exelon Corporation — Executive Overview," for more information.
(c) Other primarily consists of corporate operations and BSC.
(d) The projected capital expenditures include those incurred prior to the merger on March 12, 2012.
(e) Total projected capital expenditures do not include adjustments for non-cash activity.

Projected capital expenditures and other investments are subject to periodic review and revision to reflect changes in economic conditions and other factors.

Generation

Approximately 37% and 21% of the projected 2013 capital expenditures at Generation are for the acquisition of nuclear fuel, and investments in renewable energy generation, including Antelope Valley construction costs, respectively, with the remaining amounts reflecting additions and upgrades to existing facilities (including material condition improvements during nuclear refueling outages). Also included in the projected 2013 capital expenditures are a portion of the costs of a series of planned power uprates across Generation's nuclear fleet, which reflects the cancellation of certain nuclear power uprate projects in 2013. See "EXELON CORPORATION — Executive Overview," for more information on nuclear uprates.

ComEd, PECO and BGE

Approximately 89%, 89% and 77% of the projected 2013 capital expenditures at ComEd, PECO and BGE, respectively, are for continuing projects to maintain and improve operations, including enhancing reliability and adding capacity to the transmission and distribution systems such as ComEd's reliability related investments required under EIMA, and ComEd's, PECO's and BGE's construction commitments under PJM's RTEP. ComEd's capital expenditures includes smart grid/smart meter technology required under EIMA and for PECO and BGE capital expenditures related to its smart meter program and SGIG project, net of DOE expected reimbursements. The remaining amounts are for capital additions to support new business and customer growth.

In 2010, NERC provided guidance to transmission owners that recommends ComEd, PECO and BGE perform assessments of all their transmission lines, with the highest priority lines assessed by December 31, 2011, medium priority lines by December 31, 2012, and the lowest priority lines by December 31, 2013. In compliance with this guidance, ComEd, PECO and BGE submitted their most recent bi-annual reports to NERC in January 2013. ComEd, PECO and BGE will be incurring incremental capital expenditures associated with this guidance following the completion of the assessments. Specific projects and expenditures are identified as the assessments are completed. ComEd's, PECO's and BGE's forecasted 2013 capital expenditures above reflect capital spending for remediation to be completed in 2013.

ComEd, PECO and BGE anticipate that they will fund their capital expenditures with internally generated funds and borrowings, including ComEd's capital expenditures associated with EIMA as further discussed in Note 5 of the Combined Notes to Consolidated Financial Statements.

Cash Flows from Financing Activities

Cash flows provided by (used in) financing activities for the three months ended March 31, 2013 and 2012 by Registrant were as follows:

	Three Months Ended March 31,	
	2013	**2012**
Exelon	$ (102)	$ (649)
Generation	(87)	(601)
ComEd	164	(226)
PECO	(84)	(88)
BGE	(5)	(4)

Debt

See Note 10 of the Combined Notes to Consolidated Financial Statements for further details of the Registrants' debt issuances and retirements.

Dividends

Cash dividend payments and distributions during the three months ended March 31, 2013 and 2012 by Registrant were as follows:

	Three Months Ended March 31,	
	2013	**2012**
Exelon	$ 450	$ 350
Generation	211	600
ComEd	55	75
PECO	84	88
BGE(a)	3	3

(a) Relates to dividends paid on BGE's preference stock.

First Quarter 2013 Dividend

On February 6, 2013, the Exelon Board of Directors declared a regular quarterly dividend, paid on March 8, 2013 of $0.525 per share on Exelon's common stock.

Revised Dividend Policy

On February 6, 2013, the Exelon Board of Directors approved a revised dividend policy which contemplates a regular $0.31 per share quarterly dividend on Exelon's common stock payable beginning in the second quarter of 2013 (or $1.24 per share on an annualized basis), subject to quarterly declarations by the Exelon Board of Directors. The second quarter 2013 quarterly dividend of $0.31 per share on Exelon's common stock was approved by the Exelon Board of Directors on April 23, 2013 and will be paid during the second quarter.

Short-Term Borrowings

During the three months ended March 31, 2013, ComEd issued $220 million of commercial paper and Generation issued $13 million in short-term notes payable. During the three months ended March 31, 2012, Exelon repaid $161 million of outstanding commercial paper and ComEd issued $302 million of commercial paper.

Contributions from Parent/Member

During the three months ended March 31, 2013 and March 31, 2012, there were no contributions from Parent/Member (Exelon).

Other

For the three months ended March 31, 2013, other financing activities primarily consists of expenses paid related to the replacement of the Registrants' credit facilities. See Note 10 of the Combined Notes to Consolidated Financial Statements for additional information.

Credit Matters

The Registrants fund liquidity needs for capital investment, working capital, energy hedging and other financial commitments through cash flows from continuing operations, public debt offerings, commercial paper markets and large, diversified credit facilities. The credit facilities include $8.4 billion in aggregate total commitments of which $6.7 billion was available as of March 31, 2013, and of which no financial institution has more than 8% of the aggregate commitments. Exelon, Generation, ComEd, PECO and BGE had access to the commercial paper market during the first quarter of 2013 to fund their short-term liquidity needs, when necessary. The Registrants routinely review the sufficiency of their liquidity position, including appropriate sizing of credit facility commitments, by performing various stress test scenarios, such as commodity price movements, increases in margin-related transactions, changes in hedging levels and the impacts of hypothetical credit downgrades. The Registrants have continued to closely monitor events in the financial markets and the financial institutions associated with the credit facilities, including monitoring credit ratings and outlooks, credit default swap levels, capital raising and merger activity. See PART I. ITEM 1A. RISK FACTORS of Exelon's 2012 Annual Report on Form 10-K for further information regarding the effects of uncertainty in the capital and credit markets or significant bank failures.

The Registrants believe their cash flow from operating activities, access to credit markets and their credit facilities provide sufficient liquidity. If Generation lost its investment grade credit rating as of March 31, 2013, it would have been required to provide incremental collateral of $1,747 million, which is well within its current available credit facility capacities of $4.2 billion, which includes $1,747 million of collateral obligations for derivatives, non-derivatives, normal purchase normal sales contracts and applicable payables and receivables, net of the contractual right of offset under master netting agreements. If ComEd lost its investment grade credit rating as of March 31, 2013, it would have been required to provide incremental collateral of $111 million, which is well within its current available credit facility capacity of $780 million, which takes into account commercial paper borrowings as of March 31, 2013. If PECO lost its investment grade credit rating as of March 31, 2013, it would be required to provide collateral of $1 million pursuant to PJM's credit policy and could have been required to provide collateral of $36 million related to its natural gas procurement contracts, which, in the aggregate, are well within PECO's current available credit facility capacity of $599 million. If BGE lost its investment grade credit rating as of March 31, 2013, it would have been required to provide collateral of $3 million pursuant to PJM's credit policy and could have been required to provide collateral of $127 million related to its natural gas procurement contracts, which, in the aggregate, are well within BGE's current available credit facility capacity of $600 million.

Exelon Credit Facilities

Exelon, ComEd and BGE meet their short-term liquidity requirements primarily through the issuance of commercial paper. Generation and PECO meet their short-term liquidity requirements primarily through the issuance of commercial paper and borrowings from the intercompany money pool. The Registrants may use their respective credit facilities for general corporate purposes, including meeting short-term funding requirements and the issuance of letters of credit. See Note 10 of the Combined Notes to the Consolidated Financial Statements for further information regarding the Registrants' credit facilities.

The following table reflects the Registrants' commercial paper programs supported by the revolving credit agreements and bilateral credit agreements at March 31, 2013:

Commercial Paper Programs

Commercial Paper Issuer	Maximum Program Size	Outstanding Commercial Paper at March 31, 2013	Average Interest Rate on Commercial Paper Borrowings for the three months ended March 31, 2013
Exelon Corporate	$ 500	$ —	—
Generation	5,600	—	—
ComEd	1,000	220	0.39%
PECO	600	—	—
BGE	600	—	—

In order to maintain their respective commercial paper programs in the amounts indicated above, each Registrant must have credit facilities in place, at least equal to the amount of its commercial paper program. While the amount of its commercial paper outstanding does not reduce available capacity under a Registrant's credit agreement, a Registrant does not issue commercial paper in an aggregate amount exceeding the available capacity under its credit agreement.

Credit Agreements

					Available Capacity at March 31, 2013	
Borrower	Facility Type	Aggregate Bank Commitment(a)	Facility Draws	Outstanding Letters of Credit	Actual	To Support Additional Commercial Paper
Exelon Corporate	Syndicated Revolver	$ 500	$ —	$ 2	$ 498	$ 498
Generation	Syndicated Revolver	5,300	—	1,124	4,176	4,176
Generation	Bilaterals	375	—	374	1	1
ComEd	Syndicated Revolver	1,000	—	—	1,000	780
PECO	Syndicated Revolver	600	—	1	599	599
BGE	Syndicated Revolver	600	—	—	600	600

(a) Excludes $123 million of credit facility agreements arranged with minority and community banks at Generation, ComEd, PECO and BGE. These facilities expire on October 19, 2013, and are solely utilized to issue letters of credit. See Note 10 of the Combined Notes to the Consolidated Financial Statements for further information.

On March 14, 2013, ComEd extended its unsecured revolving credit facility with aggregate bank commitments of $1.0 billion. Under this facility, ComEd may issue letters of credit in the aggregate amount of up to $500 million. The credit agreement expires on March 28, 2018, and ComEd may request another one-year extension of that term. The credit facility also allows ComEd to request increases in the aggregate commitments of up to an additional $500 million. Any such extension or increases are subject to the approval of the lenders party to the credit agreement in their sole discretion. Costs incurred to extend the facility for ComEd were not material.

Borrowings under Exelon Corporate's, Generation's, ComEd's, PECO's and BGE's credit agreements bear interest at a rate based upon either the prime rate or a LIBOR-based rate, plus an adder based upon the registrants credit rating. Exelon Corporate, Generation, ComEd, PECO and BGE have adders of 27.5, 27.5, 27.5, 0.0 and 7.5 basis points for prime based borrowings and 127.5, 127.5, 127.5, 100.0 and 107.5 basis points for LIBOR-based borrowings. The maximum adders for prime rate borrowings and LIBOR-based rate borrowings are 65 basis points and 165 basis points, respectively. The credit agreement also requires each entity to pay a facility fee based upon the aggregate commitments under the agreement. The fee varies depending upon the respective credit ratings of each entity.

On January 23, 2013, Generation entered into a two year $75 million bilateral letter of credit facility with a bank. The credit agreement expires in January 2015. This facility will solely be utilized by Generation to issue letters of credit.

Each revolving credit agreement for Exelon, Generation, ComEd, PECO and BGE requires the affected borrower to maintain a minimum cash from operations to interest expense ratio for the twelve-month period ended on the last day of any quarter. The following table summarizes the minimum thresholds reflected in the credit agreements for the three months ended March 31, 2013:

	Exelon	Generation	ComEd	PECO	BGE
Credit agreement threshold	2.50 to 1	3.00 to 1	2.00 to 1	2.00 to 1	2.00 to 1

At March 31, 2013, the interest coverage ratios at the Registrants were as follows:

	Exelon	Generation	ComEd	PECO	BGE
Interest coverage ratio	7.89	13.67	2.76	8.52	5.56

An event of default under any Registrant's credit facility will not constitute an event of default under any of the other Registrants' credit facilities, except that a bankruptcy or other event of default in the payment of principal, premium or indebtedness in principal amount in excess of $100 million in the aggregate by Generation under its credit facility will constitute an event of default under the Exelon corporate credit facility.

Security Ratings

The Registrants' access to the capital markets, including the commercial paper market, and their respective financing costs in those markets, may depend on the securities ratings of the entity that is accessing the capital markets.

The Registrants' borrowings are not subject to default or prepayment as a result of a downgrading of securities, although such a downgrading of a Registrant's securities could increase fees and interest charges under that Registrant's credit agreements.

As part of the normal course of business, the Registrants enter into contracts that contain express provisions or otherwise permit the Registrants and their counterparties to demand adequate assurance of future performance when there are reasonable grounds for doing so. In accordance with the contracts and applicable contracts law, if the Registrants are downgraded by a credit rating agency, it is possible that a counterparty would attempt to rely on such a downgrade as a basis for making a demand for adequate assurance of future performance, which could include the posting of collateral. See Note 9 of the Combined Notes to Consolidated Financial Statements for additional information on collateral provisions.

Intercompany Money Pool

To provide an additional short-term borrowing option that will generally be more favorable to the borrowing participants than the cost of external financing, Exelon operates an intercompany money pool. Maximum amounts contributed to and borrowed from the money pool by participant during the three months ended March 31, 2013, in addition to the net contribution or borrowing as of March 31, 2013, are presented in the following table:

Contributed (borrowed) as of March 31, 2013	Maximum Contributed	Maximum Borrowed	Contributed (Borrowed)
Generation	$ —	$ 110	$ —
PECO	110	—	50
BSC	—	194	(138)
Exelon Corporate	194	N/A	88

Investments in Nuclear Decommissioning Trust Funds

Exelon and Generation maintain trust funds, as required by the NRC, to fund certain costs of decommissioning Generation's nuclear plants. The mix of securities in the trust funds is designed to provide returns to be used to fund decommissioning and to offset inflationary increases in decommissioning costs. Generation actively monitors the investment performance of the trust funds and periodically reviews asset allocations in accordance with Generation's NDT fund investment policy. Generation's investment policy establishes limits on the concentration of holdings in any one company and also in any one industry. See Note 12 of the Combined Notes to Consolidated Financial Statements for further information regarding the trust funds, the NRC's minimum funding requirements and related liquidity ramifications.

Shelf Registration Statements

On May 29, 2012, the Registrants filed a combined shelf registration statement unlimited in amount, with the SEC, which became immediately effective. As of March 31, 2013, Exelon, Generation, ComEd, PECO and BGE each had a current shelf registration statement effective with the SEC that provides for the sale of unspecified amounts of securities. The ability of each Registrant to sell securities off its shelf registration statement or to access the private placement markets will depend on a number of factors at the time of the proposed sale, including other required regulatory approvals, as applicable, the current financial condition of the Registrant, its securities ratings and market conditions.

Regulatory Authorizations

On March 1, 2013, ComEd received $470 million in long-term debt new money authority from the ICC and on February 27, 2012, ComEd received $1.3 billion in long-term debt refinancing authority from the ICC. As of March 31, 2013, ComEd had $1.4 billion available in long-term debt refinancing authority and $576 million available in new money long-term debt financing authority from the ICC. As of March 31, 2013, PECO had $1.9 billion available in long-term debt financing authority from the PAPUC. As of March 31, 2013, BGE had $1.2 billion available in long-term financing authority from MDPSC.

As of March 31, 2013, ComEd and PECO had short-term financing authority from FERC, which expires on December 31, 2013, of $2.5 billion and $1.5 billion, respectively. BGE had short-term financing authority from FERC, which expires December 31, 2014, of $0.7 billion. Generation currently has blanket financing authority it received from FERC in connection with its market-based rate authority.

Contractual Obligations and Off-Balance Sheet Arrangements

Contractual obligations represent cash obligations that are considered to be firm commitments and commercial commitments triggered by future events. See Note 17 of the Combined Notes to Consolidated Financial Statements for discussion of the Registrants' commitments.

Generation, ComEd, PECO and BGE have obligations related to contracts for the purchase of power and fuel supplies, and ComEd, PECO and BGE have obligations related to their financing trusts. The power and fuel purchase contracts and the financing trusts have been considered for consolidation in the Registrants' respective financial statements pursuant to the authoritative guidance for VIEs. See Note 1 of the Combined Notes to Consolidated Financial Statements for further information.

For an in-depth discussion of the Registrant's contractual obligations and off-balance sheet arrangements, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Contractual Obligations and Off-Balance Sheet Arrangements" in the Exelon 2012 Form 10-K.

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Item 3. Quantitative and Qualitative Disclosures about Market Risk

The Registrants are exposed to market risks associated with adverse changes in commodity prices, counterparty credit, interest rates and equity prices. Exelon's RMC approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval, and the monitoring and reporting of risk exposures. The RMC is chaired by the chief risk officer and includes the chief executive officer, 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 Risk Oversight Committee of the Exelon Board of Directors on the scope of the risk management activities. The following discussion serves as an update to ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK of the Registrants' 2012 Annual Report on Form 10-K incorporated herein by reference.

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

Commodity price risk is associated with price movements resulting from changes in supply and demand, fuel costs, market liquidity, weather conditions, governmental regulatory and environmental policies, and other factors. To the extent the amount of energy Exelon generates differs from the amount of energy it has contracted to sell, Exelon has price risk from commodity price movements. Exelon seeks to mitigate its commodity price risk through the sale and purchase of electricity, fossil fuel, and other commodities.

Generation

Normal Operations and Hedging Activities. Electricity available from Generation's owned or contracted generation supply in excess of Generation's obligations to customers, including portions of ComEd's, PECO's and BGE's retail load, is sold into the wholesale markets. To reduce price risk caused by market fluctuations, Generation enters into physical contracts as well as financial derivative contracts, including forwards, futures, swaps, and options, with approved counterparties to hedge anticipated exposures. Generation believes these instruments represent economic hedges that mitigate exposure to fluctuations in commodity prices. Generation expects the settlement of the majority of its economic hedges, including the ComEd financial swap contract, will occur during 2013 through 2015. Generation's energy contracts are accounted for under the accounting guidance for derivatives as further discussed in Note 9 of the Combined Notes to Consolidated Financial Statements.

In general, increases and decreases in forward market prices have a positive and negative impact, respectively, on Generation's owned and contracted generation positions which have not been hedged. Generation hedges commodity risk on a ratable basis over the three years leading to the spot market. 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 sales to ComEd, PECO and BGE to serve their retail load.

A portion of Generation's hedging strategy may be accomplished with fuel products based on assumed correlations between power and fuel prices, which routinely change in the market. Market price risk exposure is the risk of a change in the value of unhedged positions. The forecasted market price risk exposure for Generation's entire non-trading portfolio associated with a $5 reduction in the annual average around-the-clock energy price based on March 31, 2013 market conditions and hedged position would be an increase in pre-tax income of approximately $20 million for 2013 and a decrease in pre-tax net income of approximately $360 million and $750 million, respectively, for 2014 and 2015. Power price sensitivities are derived by adjusting power price assumptions while keeping all other price inputs constant. Generation expects to actively manage its portfolio to mitigate market price risk exposure for its unhedged position. Actual results could differ depending on the specific timing of, and markets affected by, price changes, as well as future changes in Generation's portfolio.

Proprietary Trading Activities. Generation also enters into certain energy-related derivatives for proprietary trading purposes. Proprietary trading includes all contracts entered into with the intent of benefiting from shifts or changes in market prices as opposed to those entered into with the intent of hedging or managing risk. Proprietary trading activities are subject to limits established by Exelon's RMC. The proprietary trading portfolio is subject to a risk management policy that includes stringent risk management limits, including volume, stop loss and Value-at-Risk (VaR) limits to manage exposure to market risk. Additionally, the Exelon risk management group and Exelon's RMC monitor the financial risks of the proprietary trading activities. The proprietary trading activities, which included physical volumes of 1,572 GWhs and 1,757 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 overall revenue from energy marketing activities. Trading portfolio activity for the three months ended March 31, 2013 resulted in pre-tax gains of $9 million due to net mark-to-market gains of $2 million and realized gains of $7 million. Generation uses a 95% confidence interval, assuming standard normal distribution, one day holding period, one-tailed statistical measure in calculating its VaR. The daily VaR on proprietary trading activity averaged $1 million of exposure during the quarter. Because of the relative size of the proprietary trading portfolio in comparison to Generation's total gross margin from continuing operations for the three months ended March 31, 2013 of $1,364 million, Generation has not segregated proprietary trading activity in the following tables.

Fuel Procurement. Generation procures coal and natural gas through long-term and short-term contracts, and spot-market purchases. Nuclear fuel assemblies are obtained primarily through long-term contracts for uranium concentrates, and long-term contracts for conversion services, enrichment services and fuel fabrication services. The supply markets for coal, natural gas, uranium concentrates and certain nuclear fuel services are subject to price fluctuations and availability restrictions. Supply market conditions may make Generation's procurement contracts subject to credit risk related to the potential non-performance of counterparties to deliver the contracted commodity or service at the contracted prices. Approximately 60% of Generation's uranium concentrate requirements from 2013 through 2017 are supplied by three producers. In the event of non-performance by these or other suppliers, Generation believes that replacement uranium concentrates can be obtained, although at prices that may be unfavorable when compared to the prices under the current supply agreements. Non-performance by these counterparties could have a material impact on Exelon's and Generation's results of operations, cash flows and financial positions. See Note 17 of the Combined Notes to Consolidated Financial Statements for additional information regarding uranium and coal supply agreement matters.

ComEd

The financial swap contract between Generation and ComEd was deemed prudent by the Illinois Settlement Legislation, thereby ensuring that ComEd will be entitled to receive full cost recovery in rates. The change in fair value each period is recorded by ComEd with an offset to a regulatory asset or liability. This financial swap contract between Generation and ComEd expires on May 31, 2013.

ComEd's RFP contracts are deemed to be derivatives that qualify for the normal purchases and normal sales exception under derivative accounting guidance. ComEd does not enter into derivatives for speculative or trading purposes. ComEd is permitted full recovery of its RFP contracts from retail customers with no mark-up.

On December 17, 2010, ComEd entered into several 20-year floating-to-fixed energy swap contracts with unaffiliated suppliers regarding the procurement of long-term renewable energy and associated RECs. 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 Notes 5 and 9 of the Combined Notes to Consolidated Financial Statements for additional information regarding energy procurement and derivatives.

PECO

PECO has contracts to procure electric supply that were executed through the competitive procurement process outlined in its PAPUC-approved DSP Programs, which are further discussed in Note 5 of the Combined Notes to the Consolidated Financial Statements. 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. Under the DSP Programs, PECO is permitted to recover its electric supply procurement costs from retail customers with no mark-up.

PECO has also entered into derivative natural gas contracts, which either qualify for the normal purchases and normal sales exception or have no mark-to-market balances because the derivatives are index priced, to hedge its long-term price risk in the natural gas market. PECO's hedging program for natural gas procurement has no direct impact on its financial position or results of operations as natural gas costs are fully recovered from customers under the PGC.

PECO does not enter into derivatives for speculative or proprietary trading purposes. For additional information on these contracts, see Note 9 of the Combined Notes to Consolidated Financial Statements.

BGE

BGE procures electric supply for default service customers through full requirements contracts pursuant to BGE's MDPSC-approved SOS program. BGE's full requirements contracts that are considered derivatives qualify for the normal purchases and normal sales scope exception under current derivative authoritative guidance. Under the SOS program, BGE is permitted to recover its electricity procurement costs from retail customers, plus an administrative fee which includes a shareholder return component and an incremental cost component. However, through December 2016, BGE provides all residential electric customers a credit for the residential shareholder return component of the administrative charge.

BGE has also entered into derivative natural gas contracts, which qualify for the normal purchases and normal sales scope exception, to hedge its price risk in the natural gas market. The hedging program for natural gas procurement has no direct impact on BGE's financial position. However, under BGE's market-based rates incentive mechanism, BGE's actual cost of gas is compared to a market index (a measure of the market price of gas in a given period). The difference between BGE's actual cost and the market index is shared equally between shareholders and customers.

BGE does not enter into derivatives for speculative or proprietary trading purposes. For additional information on these contracts, see Note 9 of the Combined Notes to Consolidated Financial Statements.

Trading and Non-Trading Marketing Activities. The following detailed presentation of Exelon's, Generation's, ComEd's and PECO's trading and non-trading marketing activities is included to address the recommended disclosures by the energy industry's Committee of Chief Risk Officers (CCRO).

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The following table provides detail on changes in Exelon's, Generation's, ComEd's and PECO's mark-to-market net asset or liability balance sheet position from December 31, 2012 to March 31, 2013. It indicates the drivers behind changes in the balance sheet amounts. This table incorporates the mark-to-market activities that are immediately recorded in earnings as well as the settlements from OCI to earnings and changes in fair value for the cash flow hedging activities that are recorded in accumulated OCI on the Consolidated Balance Sheets. This table excludes all normal purchase and normal sales contracts. See Note 9 of the Combined Notes to the Consolidated Financial Statements for additional information on the balance sheet classification of the mark-to-market energy contract net assets (liabilities) recorded as of March 31, 2013 and December 31, 2012.

	Generation	ComEd	Intercompany Eliminations(b)	Exelon
Total mark-to-market energy contract net assets (liabilities) at December 31, 2012(a)	$ 1,505	$ (293)	$ —	$1,212
Total change in fair value during 2013 of contracts recorded in result of operations	(340)	—	7	(333)
Reclassification to realized at settlement of contracts recorded in results of operations	(61)	—	10	(51)
Reclassification to realized at settlement from accumulated OCI(c)	(223)	—	124	(99)
Changes in fair value — energy derivatives(d)	—	133	(141)	(8)
Changes in allocated collateral	202	—	—	202
Changes in net option premium paid/(received)	3	—	—	3
Option premium amortization(e)	(21)	—	—	(21)
Other balance sheet reclassifications	(2)	—	—	(2)
Total mark-to-market energy contract net assets (liabilities) at March 31, 2013(a)	$ 1,063	$ (160)	$ —	$ 903

(a) Amounts are shown net of collateral paid to and received from counterparties.
(b) Amounts related to the five-year financial swap between Generation and ComEd are eliminated in consolidation.
(c) For Generation, includes $ 124 million of losses from reclassifications from accumulated OCI to recognize gains in net income related to settlement of the five-year financial swap contract with ComEd for the three months ended March 31, 2013.
(d) For ComEd, the changes in fair value are recorded as a change in regulatory assets or liabilities. As of March 31, 2013, ComEd recorded a $160 million regulatory asset related to its mark-to-market derivative liabilities with Generation and unaffiliated suppliers. As of March 31, 2013, this included $8 million of decreases in fair value and $133 million for reclassifications from regulatory asset to recognize cost in purchased power expense due to settlements of ComEd's five-year financial swap with Generation. As of March 31, 2013, ComEd also recorded $11 million of increases in fair value and $3 million of realized losses due to settlements associated with floating-to-fixed energy swap contracts with unaffiliated suppliers.
(e) Includes $21 million of amounts reclassified to realized at the settlement of contracts recorded to results of operations related to option premiums due to the settlement of the underlying transactions for the three months ended March 31, 2013.

Fair Values. The following tables present maturity and source of fair value for Exelon, Generation and ComEd mark-to-market commodity contract net assets (liabilities). The tables provide two fundamental pieces of information. First, the tables provide the source of fair value used in determining the carrying amount of the Registrants' total mark-to-market net assets (liabilities), net of allocated collateral. Second, the tables show the maturity, by year, of the Registrants' commodity contract net assets (liabilities), net of allocated collateral, giving an indication of when these mark-to-market amounts will settle and either generate or require cash. See Note 8 of the Combined Notes to Consolidated Financial Statements for additional information regarding fair value measurements and the fair value hierarchy.

Exelon

	Maturities Within						
	2013	2014	2015	2016	2017	2018 and Beyond	Total Fair Value
Normal Operations, Commodity derivative contracts(a)(b):							
Actively quoted prices (Level 1)	$118	$ (28)	$ (34)	$11	$ 1	$ —	$ 68
Prices provided by external sources (Level 2)	189	297	77	14	(1)	(1)	575
Prices based on model or other valuation methods (Level 3)(c)	55	102	59	37	24	(17)	260
Total	$362	$371	$102	$62	$24	$ (18)	$ 903

(a) Mark-to-market gains and losses on economic hedge and trading derivative contracts that are recorded in the results of operations.
(b) Amounts are shown net of collateral paid to and received from counterparties (and offset against mark-to-market assets and liabilities) of $233 million at March 31, 2013.
(c) Includes ComEd's net assets (liabilities) associated with the floating-to-fixed energy swap contracts with unaffiliated suppliers.

Generation

	Maturities Within						
	2013	2014	2015	2016	2017	2018 and Beyond	Total Fair Value
Normal Operations, Commodity derivative contracts(a)(b):							
Actively quoted prices (Level 1)	$118	$ (28)	$ (34)	$11	$ 1	$ —	$ 68
Prices provided by external sources (Level 2)	189	297	77	14	(1)	(1)	575
Prices based on model or other valuation methods (Level 3)	155	112	73	50	37	(7)	420
Total	$462	$381	$116	$75	$37	$ (8)	$ 1,063

(a) Mark-to-market gains and losses on economic hedge and trading derivative contracts that are recorded in the results of operations. Amounts include an $85 million gain associated with the five-year financial swap with ComEd.
(b) Amounts are shown net of collateral paid to and received from counterparties (and offset against mark-to-market assets and liabilities) of $233 million at March 31, 2013.

ComEd

	Maturities Within						
	2013	2014	2015	2016	2017	2018 and beyond	Total Fair Value
Prices based on model or other valuation methods(a)	$(100)	$(10)	$(14)	$(13)	$(13)	$ (10)	$ (160)

(a) Represents ComEd's net liabilities associated with the five-year financial swap with Generation and the floating-to-fixed energy swap contracts with unaffiliated suppliers.

Credit Risk, Collateral, and Contingent Related Features (Exelon, Generation, ComEd, PECO and BGE)

The Registrants would be exposed to credit-related losses in the event of non-performance by counterparties that enter into derivative instruments. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. See Note 9 of the Combined Notes to Consolidated Financial Statements for a detail discussion of credit risk, collateral, and contingent related features.

Generation

The following tables provide information on Generation's credit exposure for all derivative instruments, normal purchase normal sales agreements, and applicable payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of March 31, 2013. The tables further delineate that exposure by credit rating of the counterparties and provide guidance on the concentration of credit risk to individual counterparties and an indication of the duration of a company's credit risk by credit rating of the counterparties. The figures in the tables below do not include credit risk exposure from uranium procurement contracts or exposure through RTOs, ISOs, NYMEX, ICE, and Nodal commodity exchanges, which are discussed below. Additionally, the figures in the tables below do not include exposures with affiliates, including net receivables with ComEd, PECO and BGE of $44 million, $59 million and $25 million, respectively. See Note 22 of the Exelon 2012 Form 10-K for further information.

Rating as of March 31, 2013	Total Exposure Before Credit Collateral	Credit Collateral(a)	Net Exposure	Number of Counterparties Greater than 10% of Net Exposure	Net Exposure of Counterparties Greater than 10% of Net Exposure
Investment grade	$ 1,459	$ 184	$ 1,275	1	$ 387
Non-investment grade	49	29	20	—	—
No external ratings					
Internally rated — investment grade	403	5	398	1	252
Internally rated — non-investment grade	44	1	43	—	—
Total	$ 1,955	$ 219	$ 1,736	2	$ 639

Rating as of March 31, 2013	Maturity of Credit Risk Exposure: Less than 2 Years	2-5 Years	Exposure Greater than 5 Years	Total Exposure Before Credit Collateral
Investment grade	$ 991	$ 311	$ 157	$ 1,459
Non-investment grade	31	18	—	49
No external ratings				
Internally rated — investment grade	229	169	5	403
Internally rated — non-investment grade	41	2	1	44
Total	$ 1,292	$ 500	$ 163	$ 1,955

Net Credit Exposure by Type of Counterparty	As of March 31, 2013
Investor-owned utilities, marketers and power producers	$ 515
Energy cooperatives and municipalities	824
Financial Institutions	352
Other	45
Total	$ 1,736

(a) As of March 31, 2013, credit collateral held from counterparties where Generation had credit exposure included $172 million of cash and $47 million of letters of credit.

ComEd

There have been no significant changes or additions to ComEd's exposures to credit risk that are described in ITEM 1A. RISK FACTORS of Exelon's 2012 Annual Report on Form 10-K.

See Note 9 of the Combined Notes to Consolidated Financial Statements for information regarding credit exposure to suppliers.

PECO

There have been no significant changes or additions to PECO's exposures to credit risk as described in ITEM 1A. RISK FACTORS of Exelon's 2012 Annual Report on Form 10-K.

See Note 9 of the Combined Notes to Consolidated Financial Statements for information regarding credit exposure to suppliers.

BGE

There have been no significant changes or additions to BGE's exposures to credit risk as described in ITEM 1A. RISK FACTORS of Exelon's 2012 Annual Report on Form 10-K.

See Note 9 of the Combined Notes to Consolidated Financial Statements for information regarding credit exposure to suppliers.

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

Generation

As part of the normal course of business, Generation routinely enters into physical or financial contracts for the sale and purchase of electricity, fossil fuel and other commodities. These contracts either contain express provisions or otherwise permit Generation and its counterparties to demand adequate assurance of future performance when there are reasonable grounds for doing so. In accordance with the contracts and applicable law, if Generation is downgraded by a credit rating agency, especially if such downgrade is to a level below investment grade, it is possible that a counterparty would attempt to rely on such a downgrade as a basis for making a demand for adequate assurance of future performance. Depending on Generation's net position with a counterparty, the demand could be for the posting of collateral. In the absence of expressly agreed-to provisions that specify the collateral that must be provided, collateral requested will be a function of the facts and circumstances of the situation at the time of the demand. In this case, Generation believes an amount of several months of future payments (i.e. capacity payments) rather than a calculation of fair value is the best estimate for the contingent collateral obligation, which has been factored into the disclosure below. See Note 9 of the Combined Notes to Consolidated Financial Statements for information regarding collateral requirements.

Generation sells output through bilateral contracts. The bilateral contracts are subject to credit risk, which relates to the ability of counterparties to meet their contractual payment obligations. Any failure to collect these payments from counterparties could have a material impact on Exelon's and Generation's results of operations, cash flows and financial position. As market prices rise above contracted price levels, Generation is required to post collateral with purchasers; as market prices fall below contracted price levels, counterparties are required to post collateral with Generation. In order to post collateral, Generation depends on access to bank credit facilities, which serve as liquidity sources to fund collateral requirements. See Note 10 of the Combined Notes to Consolidated Financial Statements for additional information.

As of March 31, 2013, Generation had $467 million cash collateral deposit payments being held by counterparties and Generation was holding $236 million of cash collateral deposits received from counterparties, of which $233 million in net cash collateral deposits was offset against mark-to-market assets and liabilities. As of March 31, 2013, $2 million of cash collateral received was not offset against net derivative positions because it was not associated with energy-related derivatives. See Note 17 of the Combined Notes to Consolidated Financial Statements for information regarding the letters of credit supporting the cash collateral.

ComEd

As of March 31, 2013, ComEd held immaterial amounts of cash and letters of credit for the purpose of collateral from suppliers in association with energy procurement contracts and held approximately $19 million in the form of cash and letters of credit for both annual and long-term renewable energy contracts. See Notes 5 and 9 of the Combined Notes to Consolidated Financial Statements for further information.

PECO

As of March 31, 2013, PECO was not required to post collateral under its energy and natural gas procurement contracts. See Note 9 of the Combined Notes to Consolidated Financial Statements for further information.

BGE

BGE is not required to post collateral under its electric supply contracts. As of March 31, 2013, BGE was not required to post collateral under its natural gas procurement contracts, nor was it holding collateral under its electric supply and natural gas procurement contracts. See Note 9 of the Combined Notes to Consolidated Financial Statements for further information.

RTOs and ISOs (Exelon, Generation, ComEd, PECO and BGE)

Generation, ComEd, PECO and BGE participate in all, or some, of the established, real-time energy markets that are administered by PJM, ISO-NE, ISO-NY, CAISO, MISO, SPP, AESO, OIESO and ERCOT. In these areas, power is traded through bilateral agreements between buyers and sellers and on the spot markets that are operated by the RTOs or ISOs, as applicable. In areas where there is no spot market, electricity is purchased and sold solely through bilateral agreements. For sales into the spot markets administered by an RTO or ISO, the RTO or ISO maintains financial assurance policies that are established and enforced by those administrators. The credit policies of the RTOs and ISOs may, under certain circumstances, require that losses arising from the default of one member on spot market transactions be shared by the remaining participants. Non-performance or non-payment by a major counterparty could result in a material adverse impact on the Registrants' results of operations, cash flows and financial positions.

Exchange Traded Transactions (Exelon and Generation)

Generation enters into commodity transactions on NYMEX, ICE and the Nodal exchange. The NYMEX, ICE and Nodal exchange clearinghouses act as the counterparty to each trade. Transactions on the NYMEX, ICE and Nodal exchange must adhere to comprehensive collateral and margining requirements. As a result, transactions on NYMEX, ICE and Nodal exchange are significantly collateralized and have limited counterparty credit risk.

Long-Term Leases (Exelon)

Exelon's consolidated balance sheets, as of March 31, 2013, included a $700 million net investment in coal-fired plants in Georgia and Texas subject to long-term leases. This investment represents the estimated residual value of leased assets at the end of the respective lease terms of approximately $1.5 billion, less unearned income of $800 million. The lease agreements provide the lessees with fixed purchase options at the end of the lease terms which are set at prices above the then expected fair market value of the plants. If the lessees do not exercise the fixed purchase options, the lessees return the leasehold interests to Exelon and Exelon has the ability to require the lessees to arrange a service contract with a third party for a period following the lease term. In any event, Exelon is subject to residual value risk to the extent the fair value of the assets are less than the residual value. This risk is mitigated by the fair value of the fixed payments under the service contract. The term of the service contract, however, is less than the expected remaining useful life of the plants and, therefore, Exelon's exposure to residual value risk will not be mitigated by payments under the service contract in this remaining period. Lessee performance under the lease agreements is supported by collateral and credit enhancement measures, including letters of credit, surety bonds and credit swaps. Management regularly evaluates the creditworthiness of Exelon's counterparties to these long-term leases. Since 2008, the entity providing the credit enhancement for one of the lessees did not meet the credit rating requirements of the lease. Consequently, Exelon has indefinitely extended a waiver and reduction of the rating requirement, which Exelon may terminate by giving 90 days notice to the lessee. Exelon monitors the continuing credit quality of the credit enhancement party.

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 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.

Equity Price Risk (Exelon and Generation)

Exelon and Generation maintain trust funds, as required by the NRC, to fund certain costs of decommissioning Generation's nuclear plants. As of March 31, 2013, Generation's decommissioning trust funds are reflected at fair value on its Consolidated Balance Sheets. The mix of securities in the trust funds is designed to provide returns to be used to fund decommissioning and to compensate Generation for inflationary increases in decommissioning costs; however, the equity securities in the trust funds are exposed to price fluctuations in equity markets, and the value of fixed-rate, fixed-income securities are exposed to changes in interest rates. Generation actively monitors the investment performance of the trust funds and periodically reviews asset allocation in accordance with Generation's NDT fund investment policy. A hypothetical 10% increase in interest rates and decrease in equity prices would result in a $417 million reduction in the fair value of the trust assets. This calculation holds all other variables constant and assumes only the discussed changes in interest rates and equity prices. See ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS for further discussion of equity price risk as a result of the current capital and credit market conditions.

Item 4. Controls and Procedures

During the first quarter of 2013, each of Exelon's, Generation's, ComEd's, PECO's and BGE's management, including its principal executive officer and principal financial officer, evaluated its disclosure controls and procedures related to the recording, processing, summarizing and reporting of information in its periodic reports that it files with the SEC. These disclosure controls and procedures have been designed by all Registrants to ensure that (a) material information relating to that Registrant, including its consolidated subsidiaries, is accumulated and made known to Exelon's management, including its principal executive officer and principal financial officer, by other employees of that Registrant and its subsidiaries as appropriate to allow timely decisions regarding required disclosure, and (b) this information is recorded, processed, summarized, evaluated and reported, as applicable, within the time periods specified in the SEC's rules and forms. Due to the inherent limitations of control systems, not all misstatements may be detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple error or mistake. Additionally, controls could be circumvented by the individual acts of some persons or by collusion of two or more people.

Accordingly, as of March 31, 2013, the principal executive officer and principal financial officer of each of Exelon, Generation, ComEd, PECO and BGE concluded that such Registrant's disclosure controls and procedures were effective to accomplish its objectives. All Registrants continually strive to improve its disclosure controls and procedures to enhance the quality of its financial reporting and to maintain dynamic systems that change as conditions warrant. However, there have been no changes in internal control over financial reporting that occurred during the first quarter of 2013 that have materially affected, or are reasonably likely to materially affect, any of Exelon's, Generation's, ComEd's, PECO's and BGE's internal control over financial reporting.

PART II — OTHER INFORMATION

Item 1. Legal Proceedings

The Registrants are parties to various lawsuits and regulatory proceedings in the ordinary course of their respective businesses. For information regarding material lawsuits and proceedings, see (a) ITEM 3. LEGAL PROCEEDINGS of the Registrants' 2012 Form 10-K and (b) Notes 4, 5 and 17 of the Combined Notes to Consolidated Financial Statements in PART I, ITEM 1. FINANCIAL STATEMENTS of this Report. Such descriptions are incorporated herein by these references.

Item 1A. Risk Factors

Risks Related to Exelon

At March 31, 2013, the Registrants' risk factors were consistent with the risk factors described in Exelon's 2012 Annual Report on Form 10-K.

Item 4. Mine Safety Disclosures

Exelon, Generation, ComEd, PECO and BGE

Not applicable to the Registrants.

Item 6. Exhibits

Certain of the following exhibits are incorporated herein by reference under Rule 12b-32 of the Securities and Exchange Act of 1934, as amended. Certain other instruments which would otherwise be required to be listed below have not been so listed because such instruments do not authorize securities in an amount which exceeds 10% of the total assets of the applicable registrant and its subsidiaries on a consolidated basis and the relevant registrant agrees to furnish a copy of any such instrument to the Commission upon request.

Exhibit No.	Description
101.INS*	XBRL Instance
101.SCH*	XBRL Taxonomy Extension Schema
101.CAL*	XBRL Taxonomy Extension Calculation
101.DEF*	XBRL Taxonomy Extension Definition
101.LAB*	XBRL Taxonomy Extension Labels
101.PRE*	XBRL Taxonomy Extension Presentation

* XBRL information will be considered to be furnished, not filed, for the first two years of a company's submission of XBRL information.

Certifications Pursuant to Rule 13a-14(a) and 15d-14(a) of the Securities and Exchange Act of 1934 as to the Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2013 filed by the following officers for the following companies:

31-1	— Filed by Christopher M. Crane for Exelon Corporation
31-2	— Filed by Jonathan W. Thayer for Exelon Corporation
31-3	— Filed by Christopher M. Crane for Exelon Generation Company, LLC
31-4	— Filed by Bryan P. Wright for Exelon Generation Company, LLC
31-5	— Filed by Anne R. Pramaggiore for Commonwealth Edison Company
31-6	— Filed by Joseph R. Trpik, Jr. for Commonwealth Edison Company
31-7	— Filed by Craig L. Adams for PECO Energy Company
31-8	— Filed by Phillip S. Barnett for PECO Energy Company
31-9	— Filed by Kenneth W. DeFontes, Jr. for Baltimore Gas and Electric Company
31-10	— Filed by Carim V. Khouzami for Baltimore Gas and Electric Company

Certifications Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code (Sarbanes — Oxley Act of 2002) as to the Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2013 filed by the following officers for the following companies:

32-1	— Filed by Christopher M. Crane for Exelon Corporation
32-2	— Filed by Jonathan W. Thayer for Exelon Corporation
32-3	— Filed by Christopher M. Crane for Exelon Generation Company, LLC
32-4	— Filed by Bryan P. Wright for Exelon Generation Company, LLC
32-5	— Filed by Anne R. Pramaggiore for Commonwealth Edison Company
32-6	— Filed by Joseph R. Trpik, Jr. for Commonwealth Edison Company
32-7	— Filed by Craig L. Adams for PECO Energy Company
32-8	— Filed by Phillip S. Barnett for PECO Energy Company
32-9	— Filed by Kenneth W. DeFontes, Jr. for Baltimore Gas and Electric Company
32-10	— Filed by Carim V. Khouzami for Baltimore Gas and Electric Company

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SIGNATURES

Pursuant to requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

EXELON CORPORATION

/s/ CHRISTOPHER M. CRANE
Christopher M. Crane
President and Chief Executive Officer
(Principal Executive Officer)

/s/ JONATHAN W. THAYER
Jonathan W. Thayer
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

/s/ DUANE M. DESPARTE
Duane M. DesParte
Senior Vice President and Corporate Controller
(Principal Accounting Officer)

May 9, 2013

Pursuant to requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

EXELON GENERATION COMPANY, LLC

/s/ CHRISTOPHER M. CRANE
Christopher M. Crane
President
(Principal Executive Officer)

/s/ BRYAN P. WRIGHT
Bryan P. Wright
Chief Financial Officer
(Principal Financial Officer)

/s/ ROBERT M. AIKEN
Robert M. Aiken
Chief Accounting Officer
(Principal Accounting Officer)

May 9, 2013

Pursuant to requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

COMMONWEALTH EDISON COMPANY

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

/s/ JOSEPH R. TRPIK, JR.
Joseph R. Trpik, Jr.
Senior Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

/s/ GERALD J. KOZEL
Gerald J. Kozel
Vice President and Controller
(Principal Accounting Officer)

May 9, 2013

Pursuant to requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

PECO ENERGY COMPANY

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

May 9, 2013

Pursuant to requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

BALTIMORE GAS AND ELECTRIC COMPANY

/s/ KENNETH W. DEFONTES, JR.	/s/ CARIM V. KHOUZAMI
Kenneth W. DeFontes, Jr. President and Chief Executive Officer (Principal Executive Officer)	Carim V. Khouzami Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ DAVID M. VAHOS	
David M. Vahos Vice President and Controller (Principal Accounting Officer)	

May 9, 2013

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

I, Christopher M. Crane, certify that:

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

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

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

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

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

/s/ CHRISTOPHER M. CRANE

President and Chief Executive Officer
(Principal Executive Officer)

Date: May 9, 2013

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

I, Jonathan W. Thayer, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Exelon Corporation;

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

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

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

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

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

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

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

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

/s/ JONATHAN W. THAYER

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

Date: May 9, 2013

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

I, Christopher M. Crane, certify that:

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

/s/ CHRISTOPHER M. CRANE
President
(Principal Executive Officer)

Date: May 9, 2013

Exhibit 31-4

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

I, Bryan P. Wright, certify that:

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

/s/ BRYAN P. WRIGHT

Chief Financial Officer
(Principal Financial Officer)

Date: May 9, 2013

Exhibit 31-5

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

I, Anne R. Pramaggiore, certify that:

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

/s/ ANNE R. PRAMAGGIORE

President and Chief Executive Officer
(Principal Executive Officer)

Date: May 9, 2013

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

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

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

/s/ JOSEPH R. TRPIK, JR.

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

Date: May 9, 2013

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

I, Craig L. Adams, certify that:

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

/s/ CRAIG L. ADAMS

President and Chief Executive Officer
(Principal Executive Officer)

Date: May 9, 2013

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

I, Phillip S. Barnett, certify that:

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

/s/ PHILLIP S. BARNETT

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

Date: May 9, 2013

Exhibit 31-9

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

I, Kenneth W. DeFontes, Jr., certify that:

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

/s/ KENNETH W. DEFONTES, JR.
President and Chief Executive Officer
(Principal Executive Officer)

Date: May 9, 2013

Exhibit 31-10

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

I, Carim V. Khouzami, certify that:

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

/s/ CARIM V. KHOUZAMI

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

Date: May 9, 2013

Exhibit 32-1

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Exelon Corporation for the quarterly period ended March 31, 2013, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Exelon Corporation.

/s/ CHRISTOPHER M. CRANE
Christopher M. Crane
President and Chief Executive Officer

Date: May 9, 2013

Exhibit 32-2

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Exelon Corporation for the quarterly period ended March 31, 2013, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Exelon Corporation.

/s/ JONATHAN W. THAYER

Jonathan W. Thayer
Executive Vice President and Chief Financial Officer

Date: May 9, 2013

Exhibit 32-3

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Exelon Generation Company, LLC for the quarterly period ended March 31, 2013, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Exelon Generation Company, LLC.

/s/ CHRISTOPHER M. CRANE

Christopher M. Crane

President

Date: May 9, 2013

Exhibit 32-4

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Exelon Generation Company, LLC for the quarterly period ended March 31, 2013, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Exelon Generation Company, LLC.

/s/ BRYAN P. WRIGHT

Bryan P. Wright
Chief Financial Officer

Date: May 9, 2013

Exhibit 32-5

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Commonwealth Edison Company for the quarterly period ended March 31, 2013, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Commonwealth Edison Company.

/s/ ANNE R. PRAMAGGIORE

Anne R. Pramaggiore
President and Chief Executive Officer

Date: May 9, 2013

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Commonwealth Edison Company for the quarterly period ended March 31, 2013, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Commonwealth Edison Company.

/s/ JOSEPH R. TRPIK, JR.
Joseph R. Trpik, Jr.
Senior Vice President, Chief Financial Officer and Treasurer

Date: May 9, 2013

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of PECO Energy Company for the quarterly period ended March 31, 2013, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of PECO Energy Company.

/s/ CRAIG L. ADAMS

Craig L. Adams
President and Chief Executive Officer

Date: May 9, 2013

Exhibit 32-8

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of PECO Energy Company for the quarterly period ended March 31, 2013, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of PECO Energy Company.

/s/ PHILLIP S. BARNETT

Phillip S. Barnett
Senior Vice President, Chief Financial Officer and
Treasurer

Date: May 9, 2013

Exhibit 32-9

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Baltimore Gas and Electric Company for the quarterly period ended March 31, 2013, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Baltimore Gas and Electric Company.

/s/ KENNETH W. DEFONTES, JR.

Kenneth W. DeFontes, Jr.
President and Chief Executive Officer

Date: May 9, 2013

Exhibit 32-10

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Baltimore Gas and Electric Company for the quarterly period ended March 31, 2013, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Baltimore Gas and Electric Company.

/s/ CARIM V. KHOUZAMI

Carim V. Khouzami
Senior Vice President, Chief Financial Officer and Treasurer

Date: May 9, 2013