Revenue Recognition (Exelon, Generation, ComEd, PECO and BGE)

Sources of Revenue and Selection of Accounting Treatment. The Registrants earn revenues from various business activities including: the sale of energy and energy-related products, such as natural gas, capacity, and other commodities in non-regulated markets (wholesale and retail)*;* the sale and delivery of electricity and natural gas in regulated markets; and the provision of other energy-related non-regulated products and services.

The appropriate accounting treatment for revenue recognition is based on the nature of the underlying transaction and applicable accounting standards. The Registrants primarily use accrual and mark-to-market accounting as discussed in more detail below.

Accrual Accounting. Under accrual accounting, the Registrants record revenues in the period when services are rendered or energy is delivered to customers. The Registrants generally use accrual accounting to recognize revenues for sales of electricity, natural gas, and other commodities as part of their physical delivery activities. The Registrants enter into these sales transactions using a variety of instruments, including non-derivative agreements, derivatives that qualify for and are designated as normal purchases and normal sales (NPNS) of commodities that will be physically delivered, sales to utility customers under regulated service tariffs, and spot-market sales, including settlements with independent system operators.

Mark-to-Market Accounting. The Registrants record revenues using the mark-to-market method of accounting for transactions that meet the definition of a derivative for which they are not permitted, or have not elected, the NPNS exception. These mark-to-market transactions primarily relate to risk management activities and economic hedges of other accrual activities. Mark-to-market revenues include: inception gains or losses on new transactions where the fair value is observable and realized; and unrealized gains and losses from changes in the fair value of open contracts.

Use of Estimates. Estimates are based upon actual costs incurred and investments in rate base for the period and the rates of return on common equity and associated regulatory capital structure allowed under the applicable tariff. The estimated reconciliations can be affected by, among other things, variances in costs incurred and investments made and actions by regulators or courts.

The determination of Generation's energy sales, excluding the retail business, is based on estimated amounts delivered as well as fixed quantity sales. At the end of each month, amounts of energy delivered to customers during the month are estimated and the corresponding unbilled revenue is recorded. Increases in volumes delivered to the wholesale customers in the period, as well as price, would increase unbilled revenue.

Unbilled Revenues*.* The determination of Generation's, ComEd's, PECO's and BGE's retail energy sales to individual customers is based on systematic readings of customer meters generally on a monthly basis. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated, and corresponding unbilled revenue is recorded. The measurement of unbilled revenue is affected by the following factors: daily customer usage measured by generation or gas throughput volume, customer usage by class, losses of energy during delivery to customers and applicable customer rates. Increases or decreases in volumes delivered to the utilities' customers and favorable or unfavorable rate mix due to changes in usage patterns in customer classes in the period could be significant to the calculation of unbilled revenue. In addition, volumes may fluctuate monthly as a result of customers electing to use an alternate supplier, which could be significant to the calculation of unbilled revenue since unbilled commodity receivables are not recorded for these customers. Changes in the timing of meter reading schedules and the number and type of customers scheduled for each meter reading date would also have an effect on the measurement of unbilled revenue; however, total operating revenues would remain materially unchanged.

See Note 6 of the Combined Notes to Consolidated Financial Statements for additional information.

Regulated Transmission & Distribution Revenues**.** ComEd's EIMA distribution formula rate tariff provides for annual reconciliations to the distribution revenue requirement. As of the balance sheet dates, ComEd has recorded its best estimates of the distribution revenue impact resulting from changes in rates that ComEd believes are probable of approval by the ICC in accordance with the formula rate mechanism. Estimates are based upon actual costs incurred and investments in rate base for the period and the rates of return on common equity and associated regulatory capital structure allowed under the applicable tariff. The estimated reconciliation can be affected by, among other things, variances in costs incurred and investments made and actions by regulators or courts.

ComEd's and BGE's FERC transmission formula rate tariffs provide for annual reconciliations to the transmission revenue requirements. As of the balance sheet dates, ComEd and BGE have recorded the best estimate of their respective transmission revenue impact resulting from changes in rates that ComEd and BGE believe are probable of approval by FERC in accordance with the formula rate mechanism. Estimates are based upon actual costs incurred and investments in rate base for the period and the rates of return on common equity and associated regulatory capital structure allowed under the applicable tariff. The estimated reconciliation can be affected by, among other things, variances in costs incurred and investments made and actions by regulators or courts.

Allowance for Uncollectible Accounts (Exelon, Generation, ComEd, PECO and BGE)

The allowance for uncollectible accounts reflects the Registrants' best estimates of losses on the accounts receivable balances. For Generation, the allowance is based on accounts receivable aging historical experience and other currently available information. ComEd and PECO estimate the allowance for uncollectible accounts on customer receivables by applying loss rates developed specifically for each company to the outstanding receivable balance by risk segment. Risk segments represent a group of customers with similar credit quality indicators that are computed based on various attributes, including delinquency of their balances and payment history. Loss rates applied to the accounts receivable balances are based on historical average charge-offs as a percentage of accounts receivable in each risk segment. BGE estimates the allowance for uncollectible accounts on customer receivables by assigning reserve factors for each aging bucket. These percentages were derived from a study of billing progression which determined the reserve factors by aging bucket. ComEd, PECO and BGE customers' accounts are generally considered delinquent if the amount billed is not received by the time the next bill is issued, which normally occurs on a monthly basis. ComEd, PECO and BGE customer accounts are written off consistent with approved regulatory requirements. ComEd's, PECO's and BGE's provisions for uncollectible accounts will continue to be affected by changes in volume, prices and economic conditions as well as changes in ICC, PAPUC and MDPSC regulations, respectively. See Note 6 of the Combined Notes to Consolidated Financial Statements for additional information regarding accounts receivable.

Results of Operations by Business Segment

The comparisons of operating results and other statistical information for the years ended December 31, 2013, 2012 and 2011 set forth below include intercompany transactions, which are eliminated in Exelon's consolidated financial statements.

Net Income (Loss) on Common Stock by Business Segment

	2013	2012 (a)	Favorable (unfavorable) 2013 vs. 2012 variance	2011	Favorable (unfavorable) 2012 vs. 2011 variance
		$	$	$	$
Exelon	$ 1,719	1,160	559	2,495	(1,335)
Generation	1,070	562	508	1,771	(1,209)
ComEd	249	379	(130)	416	(37)

PECO	388	377	11	385	(8)
BGE	197	(9)	206	123	(132)

(a) For BGE, reflects BGE's operations for the year ended December 31, 2012. For Exelon and Generation, includes the operations of the Constellation and BGE from the date of the merger, March 12, 2012, through December 31, 2012.

Results of Operations—Generation

	2013	2012(b)	Favorable (unfavorable) 2013 vs. 2012 variance	2011	Favorable (unfavorable) 2012 vs. 2011 variance
Operating revenues	$ 15,630	$ 14,437	$ 1,193	$ 10,447	$ 3,990
Purchased power and fuel expense	8,197	7,061	(1,136)	3,589	(3,472)
Revenue net of purchased power and fuel expense [(a)]	7,433	7,376	57	6,858	518
Other operating expenses					
Operating and maintenance	4,534	5,028	494	3,148	(1,880)
Depreciation and amortization	856	768	(88)	570	(198)
Taxes other than income	389	369	(20)	264	(105)
Total other operating expenses	5,779	6,165	386	3,982	(2,183)
Equity in earnings (losses) of unconsolidated affiliates	10	(91)	101	(1)	(90)
Operating income	1,664	1,120	544	2,875	(1,755)
Other income and (deductions)					
Interest expense	(357)	(301)	(56)	(170)	(131)
Other, net	368	239	129	122	117
Total other income and (deductions)	11	(62)	73	(48)	(14)
Income before income taxes	1,675	1,058	617	2,827	(1,769)
Income taxes	615	500	(115)	1,056	556
Net income	1,060	558	502	1,771	(1,213)
Net loss attributable to non-controlling interest	(10)	(4)	(6)	—	4
Net income attributable to membership interest	$ 1,070	$ 562	$ 508	$ 1,771	$ (1,209)

(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.
(b) Includes the operations of Constellation from the date of the merger, March 12, 2012, through December 31, 2012.

Net Income Attributable to Membership Interest

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. Generation's net income attributable to membership interest increased compared to the same period in 2012 primarily due to higher revenues, net of purchased power and fuel expense, lower operating and maintenance expense and higher earnings from Generation's interest in CENG; partially offset by impairment of certain generating assets, higher depreciation expense, higher property taxes, and higher interest expense. The increase in revenues, net or purchased power and fuel expense was primarily due to increased capacity prices and higher nuclear volume partially offset by lower realized energy prices, higher nuclear fuel costs, and lower mark-to-market gains in 2013. The decrease in operating and maintenance expense was largely due to 2012 costs associated with a settlement with FERC in 2012 and decreases in transaction costs and employee-related costs associated with the merger.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. Generation's net income attributable to membership interest decreased compared to the same period in 2012 primarily due to higher operating expenses, the loss on the sale of Brandon Shores, Wagner and C.P. Crane (collectively Maryland generating stations) and the amortization of acquired energy contracts recorded at fair value at the merger date; offset by higher revenues, net of purchased power and fuel expense and favorable NDT fund performance. The increase in operating expenses was due to the addition of Constellation's financial results from March 12, 2012, costs related to a 2012 settlement with FERC and transaction and employee-related severance costs associated with the merger. The increase in revenues, net of purchased power and fuel expense was also primarily due to the merger. See Note 4 for additional information regarding the loss on the sale of three Maryland generating stations.

Revenue Net of Purchased Power and Fuel Expense

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

- Mid-Atlantic represents operations in the eastern half of PJM, which includes Pennsylvania, New Jersey, Maryland, Virginia, West Virginia, Delaware, the District of Columbia and parts of North Carolina.
- Midwest represents operations in the western half of PJM, which includes portions of Illinois, Indiana, Ohio, Michigan, Kentucky and Tennessee, and the United States footprint of MISO excluding MISO's Southern Region, which covers all or most of North Dakota, South Dakota, Nebraska, Minnesota, Iowa, Wisconsin, the remaining parts of Illinois, Indiana, Michigan and Ohio not covered by PJM, and parts of Montana, Missouri and Kentucky.
- New England represents the operations within ISO-NE covering the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont.
- New York represents operations within 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, MISO's Southern Region, and the remaining portions of the SERC not included within MISO or PJM, which includes all or most of Florida, Arkansas, Louisiana, Mississippi, Alabama, Georgia, Tennessee, North Carolina, South Carolina and parts of Missouri, Kentucky and Texas. Generation's South region also includes operations in the SPP, covering Kansas, Oklahoma, most of Nebraska and parts of New Mexico, Texas, Louisiana, Missouri, Mississippi and Arkansas.
  - West represents operations in the WECC, which includes California ISO, and covers the states of California, Oregon, Washington, Arizona, Nevada, Utah, Idaho, Colorado, and parts of New Mexico, Wyoming and South Dakota.
  - Canada represents operations across the entire country of Canada and includes 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, 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 and allocates resources 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 year ended December 31, 2013 compared to 2012 and 2012 compared to 2011, Generation's revenue net of purchased power and fuel expense by region were as follows:

			2013 vs.2012			2012 vs. 2011	
	2013	2012(a)	Variance	% Change	2011	Variance	% Change
Mid-Atlantic (b) (f)	$ 3,270	$ 3,433	$ (163)	(4.7)%	$ 3,350	$ 83	2.5%
Midwest (c)	2,586	2,998	(412)	(13.7)%	3,547	(549)	(15.5)%
New England	185	196	(11)	(5.6)%	9	187	n.m.
New York (f)	(4)	76	(80)	(105.3)%	—	76	n.m.
ERCOT	436	405	31	7.7%	84	321	n.m.
Other Regions (d)	201	131	70	53.4%	(14)	145	n.m.
Total electric revenue net of purchased power and fuel expense	$ 6,674	$ 7,239	$ (565)	(7.8)%	$ 6,976	$ 263	3.8%
Proprietary Trading	(8)	(14)	6	42.9%	24	(38)	n.m.
Mark-to-market gains (losses)	504	515	(11)	(2.1)%	(288)	803	n.m.
Other (e)	263	(364)	627	n.m.	146	(510)	n.m.
Total revenue net of purchased power and fuel expense	$ 7,433	$ 7,376	$ 57	0.8%	$ 6,858	$ 518	7.6%

(a) Includes results for Constellation business transferred to Generation 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 merger date of $488 million and $1,098 million pre-tax for the twelve months ended December 31, 2013 and December 31, 2012, respectively.
(f) Includes $542 million and $450 million of purchased power from CENG in the Mid-Atlantic and New York regions, respectively, for the year ended December 31, 2013. Includes $487 million and $306 million of purchased power from CENG in the Mid-Atlantic and New York regions, respectively, for the year ended December 31, 2012. See Note 25 of the Combined Notes to Consolidated Financial Statements for additional information.

Generation's supply sources by region are summarized below:

			2013 vs. 2012			2012 vs. 2011	
Supply source (GWh)	**2013**	**2012 (a)**	**Variance**	**% Change**	**2011**	**Variance**	**% Change**
Nuclear generation (b)							
Mid-Atlantic	48,881	47,337	1,544	3.3%	47,287	50	0.1%
Midwest	93,245	92,525	720	0.8%	92,010	515	0.6%
	142,126	139,862	2,264	1.6%	139,297	565	0.4%

Fossil and renewables (b)							
Mid-Atlantic (b)(d)	11,714	8,808	2,906	33.0%	7,572	1,236	16.3%
Midwest	1,478	971	507	52.2%	596	375	62.9%
New England	10,896	9,965	931	9.3%	8	9,957	n.m.
ERCOT	6,453	6,182	271	4.4%	2,030	4,152	n.m.
Other Regions (e)	6,664	5,913	751	12.7%	1,432	4,481	n.m.
	37,205	31,839	5,366	16.9%	11,638	20,201	n.m.
			-				
Purchased power							
Mid-Atlantic (c)	14,092	20,830	(6,738)	(32.3)%	2,898	17,932	n.m.
Midwest	4,408	9,805	(5,397)	(55.0)%	5,970	3,835	64.2%
New England	7,655	9,273	(1,618)	(17.4)%	—	9,273	n.m.
New York (c)	13,642	11,457	2,185	19.1%	—	11,457	n.m.
ERCOT	15,063	23,302	(8,239)	(35.4)%	7,537	15,765	n.m.
Other Regions (e)	14,931	17,327	(2,396)	(13.8)%	2,503	14,824	n.m.
			-				
	69,791	91,994	(22,203)	(24.1)%	18,908	73,086	n.m.
Total supply by region (f)							
Mid-Atlantic (g)	74,687	76,975	(2,288)	(3.0)%	57,757	19,218	33.3%
Midwest (h)	99,131	103,301	(4,170)	(4.0)%	98,576	4,725	4.8%
New England	18,551	19,238	(687)	(3.6)%	8	19,230	n.m.
New York	13,642	11,457	2,185	19.1%	—	11,457	n.m.
ERCOT	21,516	29,484	(7,968)	(27.0)%	9,567	19,917	n.m.
Other Regions (e)	21,595	23,240	(1,645)	(7.1)%	3,935	19,305	n.m.
Total supply	249,122	263,695	(14,573)	(5.5)%	169,843	93,852	55.3%

(a) Includes results for the Constellation business transferred to Generation 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 includes physical volumes of 12,067 GWh and 9,925 GWh in the Mid-Atlantic and 12,165 GWh and 9,350 GWh in New York as a result of the PPA with CENG for the years ended December 31, 2013 and 2012 respectively.
(d) Excludes 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 8,762 GWh, 12,958 GWh and 5,742 GWh for the years ended December 31, 2013, 2012 and 2011 respectively.
(g) Includes sales to PECO through the competitive procurement process of 5,070 GWh, 7,762 GWh, and 7,041 GWh for the years ended December 31, 2013, 2012 and 2011 respectively. Sales to BGE of 5,595 GWh and 3,766 GWh were included for the years ended December 31, 2013 and 2012 respectively.
(h) Includes sales to ComEd under the RFP procurement of 7,491 GWh, 4,152 GWh and 4,731 GWh for the years ended December 31, 2013, 2012 and 2011 respectively.

.

The following table presents electric revenue net of purchased power and fuel expense per MWh of electricity sold during the year ended December 31, 2013 as compared to the same period in 2012 and 2012 as compared to the same period in 2011.

$/MWh	**2013**	**2012 (a)**	**2013 vs. 2012 % Change**	**2011**	**2012 vs. 2011 % Change**
Mid-Atlantic (b)	$ 43.78	$ 44.60	(1.8)%	$ 58.00	(23.1)%
Midwest (c)	26.09	29.02	(10.1)%	35.99	(19.4)%
New England	9.97	10.19	(2.1)%	n.m.	n.m.

New York	(0.29)	6.63	(104.4)%	n.m.	n.m.
ERCOT	20.26	13.74	47.5%	8.78	56.5%
Other Regions (d)	9.31	5.64	65.0%	(3.56)	n.m.
Electric revenue net of purchased power and fuel expense per MWh (e)(f)	$ 26.79	$ 27.45	(2.4)%	$ 41.07	(33.2)%

(a) Includes financial results for the Constellation business transferred to Generation beginning on March 12, 2012, the date the merger was completed.
(b) Includes sales to PECO of $405 million (5,070 GWh), $536 million (7,762 GWh) and $508 million (7,041 GWh) for the years ended December 31, 2013, 2012 and 2011, respectively. Sales to BGE of $455 million (5,595 GWh) and $322 million (3,766 GWh) were included for the years ended December 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 $283 million (7,491 GWh), $162 million (4,152 GWh) and $179 million (4,731 GWhs) and settlements of the ComEd swap of $230 million, $627 million and $474 million for years ended December 31, 2013, 2012 and 2011, 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 years ended December 31, 2013, 2012 and 2011, respectively, and excludes the mark-to-market impact of Generation's economic hedging activities.
(f) Excludes Generation's other business activities not allocated to a region, including retail and wholesale gas, upstream natural gas, proprietary trading, energy efficiency, energy management and demand response. Also excludes Generation's compensation under the reliability-must-run rate schedule, 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, and amortization of certain intangible assets relating to commodity contracts recorded at fair value as a result of the Exelon and Constellation merger of $488 million and $1,098 million, respectively.

Mid-Atlantic

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The decrease in revenue net of purchased power and fuel expense in the Mid-Atlantic of $163 million was primarily due to lower realized power prices and increased nuclear fuel costs, partially offset by the addition of Constellation in 2012, higher capacity revenues, and higher nuclear revenues.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The increase in revenue net of purchased power and fuel expense in the Mid-Atlantic of $83 million was primarily due to the addition of Constellation in 2012 and higher capacity revenues, partially offset by lower realized power prices and increased nuclear fuel costs.

Midwest

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The decrease in revenue net of purchased power and fuel expense in the Midwest of $412 million was primarily due to lower realized power prices, increased nuclear fuel costs, and lower capacity revenues, partially offset by higher nuclear revenues.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The decrease in revenue net of purchased power and fuel expense in the Midwest of $549 million was primarily due to lower capacity revenues, increased nuclear fuel costs, and lower realized power prices, partially offset by decreased congestion costs.

New England

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The $11 million decrease in revenue net of purchased power and fuel expense in New England is primarily due to lower realized energy prices, partially offset by the addition of Constellation in 2012. Prior to the merger, New England was not a significant contributor to revenue net of purchased power and fuel expense at Generation.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The $187 million increase in revenue net of purchased power and fuel expense in New England was the result of the Constellation merger. Prior to the merger, New England was not a significant contributor to revenue net of purchased power and fuel expense at Generation.

New York

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The $80 million decrease in revenue net of purchased power and fuel expense in New York was primarily due to decreased realized energy prices, partially offset by the addition of Constellation. Prior to the merger, New York was not a significant contributor to revenue net of purchased power and fuel expense at Generation.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The $76 million increase in revenue net of purchased power and fuel expense in New York was the result of the Constellation merger. Prior to the merger, New York was not a significant contributor to revenue net of purchased power and fuel expense at Generation.

ERCOT

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The $31 million increase in revenue net of purchased power and fuel expense in ERCOT was primarily due to increased realized energy prices and the addition of Constellation in 2012, partially offset by a decrease due to the termination of an energy supply contract with a retail power supply company that was previously a consolidated variable interest entity. As a result of the termination, Generation no longer has a variable interest in the retail supply company and ceased consolidation of the entity during the third quarter of 2013.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The $321 million increase in revenue net of purchased power and fuel expense in ERCOT was primarily as a result of the addition of Constellation in 2012, partially offset by a decrease in revenue net of purchased power and fuel expense in the legacy Generation ERCOT portfolio driven by the performance of Generation's generating units during extreme weather events that occurred in Texas in February and August 2011.

Other Regions

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The $70 million increase in revenue net of purchased power and fuel expense in Other Regions was primarily as a result of the addition of Constellation in 2012, in addition to increased renewable generation.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The $145 million increase in revenue net of purchased power and fuel expense in Other Regions was primarily as a result of the Constellation merger.

Mark-to-market

Year Ended December 31, 2013 Compared to Year Ended December 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 gains on economic hedging activities were $504 million in 2013 compared to gains of $515 million in 2012. See Notes 11 and 12 of the Combined Notes to the Consolidated Financial Statements for information on gains and losses associated with mark-to-market derivatives.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. 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 gains on economic hedging activities were $515 million in 2012 compared to losses of $288 million in 2011. See Note 11 and 12 of the Combined Notes to the Consolidated Financial Statements for information on gains and losses associated with mark-to-market derivatives.

Other

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The $627 million increase in other revenue net of purchased power and fuel was primarily due to reduced amortization expense of the acquired energy contracts recorded at fair value at the merger date. In addition, the increase is also attributable to results from activities acquired as part of the 2012 merger with Constellation including retail gas, energy efficiency, energy management and demand response, upstream natural gas, and the design and construction of renewable energy facilities. These increases were partially offset by the reduction in revenues net of purchased power and fuel expense from the sale 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. See Note 4 of the Combined Notes to Consolidated Financial Statements for information regarding contract intangibles and assets planned for divestiture as a result of the Constellation merger.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The $510 million decrease in other revenue net of purchased power and fuel was primarily due to increased amortization expense of the acquired energy contracts recorded at fair value at the merger date. This decrease was partially offset by results from activities acquired as part of the 2012 merger with Constellation including 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 includes the results of Brandon Shores, H.A. Wagner and C.P. Crane, the generating facilities divested in fourth quarter of 2012 as a result of the Exelon and Constellation merger. See Note 4 of the Combined Notes to Consolidated Financial Statements for information regarding contract intangibles and assets planned for divestiture as a result of the Constellation merger.

Nuclear Fleet Capacity Factor and Production Costs

The following table presents nuclear fleet operating data for 2013, as compared to 2012 and 2011, for the Generation-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.

	2013	2012	2011
Nuclear fleet capacity factor [(a)]	94.1%	92.7%	93.3%
Nuclear fleet production cost per MWh [(a)]	$ 19.83	$ 19.50	$ 18.86

(a) Excludes Salem, which is operated by PSEG Nuclear, LLC, and CENG's nuclear facilities, which are operated by CENG. Reflects ownership percentage of stations operated by Exelon.

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The nuclear fleet capacity factor, which excludes Salem, increased primarily due to a lower number of planned refueling outage days in 2013, partially offset by a higher number of non-refueling outage days. For 2013 and 2012, planned refueling outage days totaled 233 and 274, respectively, and non-refueling outage days totaled 75 and 73, respectively. Higher nuclear fuel costs and higher plant operating and maintenance costs, partially offset by higher number of net MWhs generated resulted in a higher production cost per MWh during 2013 as compared to 2012.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The nuclear fleet capacity factor, which excludes Salem, decreased primarily due to a higher number of non-refueling outage days, partially offset by a lower number of planned refueling outage days in 2012. For 2012 and 2011, planned refueling outage days totaled 274 and 283, respectively, and non-refueling outage days totaled 73 and 52, respectively. Higher nuclear fuel costs resulted in a higher production cost per MWh during 2012 as compared to 2011.

Operating and Maintenance Expense

The changes in operating and maintenance expense for 2013 compared to 2012, consisted of the following:

	Increase (Decrease)
Plant retirements and divestitures (a)	$ (440)
FERC settlement (b)	(195)
Constellation merger and integration costs	(107)
Maryland commitments	(35)
Bodily injury costs (c)	(16)
Nuclear refueling outage costs, including the co-owned Salem plant (d)	(14)
Corporate allocations (e)	(5)
Labor, other benefits, contracting and materials (f)	160
Impairment and related charges of certain generating assets	160
Midwest generation bankruptcy charges	11
Pension and non-pension postretirement benefits expense	5
Other	(18)
Decrease in operating and maintenance expense	$ (494)

(a) Reflects the operating and maintenance expense associated with the generating assets retired or divested during 2012.
(b) 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.
(c) Reflects decreased asbestos-related bodily injury expense for 2013 compared to 2012.
(d) Reflects the impact of decreased planned refueling outage days during 2013.
(e) The decrease in cost allocations during 2013 primarily reflects merger synergy savings for Exelon's corporate operations and shared service entities, partially offset by the impact of an increased share of corporate allocated costs due to the merger.
(f) Includes cost of sales of our other business activities that are not allocated to a region.

The changes in operating and maintenance expense for 2012 compared to 2011, consisted of the following:

	Increase (Decrease)
Labor, other benefits, contracting and materials (a)	$ 845
Loss on the sale of Maryland Clean Coal assets (b)	278
FERC settlement (c)	195

Constellation merger and integration costs	182
Corporate allocations (d)	175
Pension and non-pension postretirement benefits expense	76
Maryland commitments (e)	35
Nuclear refueling outage costs, including the co-owned Salem plant (f)	(52)
Other	146
Increase in operating and maintenance expense	$ 1,880

(a) Includes cost of sales of our other business activities that are not allocated to a region.
(b) Represents expense recorded during the third quarter of 2012 due to the reduction in book value. Upon completion of the November 30, 2012 transaction, Generation recorded a $6 million gain within Other, net in its Consolidated Statements of Operations and Comprehensive Income. The net loss on the sale of the Maryland Clean Coal assets was $272 million. See 4 of the Combined Notes to Consolidated Financial Statements for additional information.
(c) 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.
(d) Reflects an increased share of corporate allocated costs due to the merger.
(e) Reflects costs incurred as part of the Maryland order approving the merger.
(f) Reflects the impact of decreased planned refueling outages during 2012.

Depreciation and Amortization

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The increase in depreciation and amortization expense was primarily a result of higher plant balances due to the addition of Constellation facilities and ongoing capital additions.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The increase in depreciation and amortization expense was primarily a result of higher plant balances due to the addition of Constellation facilities; and capital additions and other upgrades to legacy plants.

Taxes Other Than Income

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The increase was primarily due to the addition of Constellation's financial results in 2012.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The increase was primarily due to the addition of Constellation's financial results in 2012.

Equity in Earnings (Losses) of Unconsolidated Affiliates

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. Equity in earnings (losses) of unconsolidated affiliates increased primarily due to $50 million favorable net income generated from Exelon's equity investment in CENG and a reduction of $58 million of amortization of the basis difference in CENG recorded at fair value at the merger date.

Interest Expense

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The increase in interest expense is primarily due to the increase in long-term debt as a result of the merger and increased project financing.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The increase in interest expense is primarily due to the increase in long-term debt as a result of the merger.

Other, Net

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The increase of $129 million in other, net primarily reflects $85 million of credit facility termination fees recorded in 2012 and increased net realized and unrealized gains related to the NDT funds of Generation's Non-Regulatory

Agreement Units compared to net realized and unrealized gains in 2012, as described in the table below. Additionally, the increase reflects income related to the contractual elimination of income tax expense associated with the NDT funds of the Regulatory Agreement Units.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The increase of $117 million in other, net primarily reflects a $36 million bargain purchase gain associated with the August 2011 acquisition of Wolf Hollow, $32 million of interest income from a one-time NDT fund special transfer tax deduction in 2011, net realized and unrealized gains related to the NDT funds of Generation's Non-Regulatory Agreement Units compared to net realized and unrealized losses in 2011, as described in the table below, offset by $85 million of credit facility termination fees recorded in 2012. Additionally, the increase reflects income related to the contractual elimination of income tax expense associated with the NDT funds of the Regulatory Agreement Units.

The following table provides unrealized and realized gains (losses) on the NDT funds of the Non-Regulatory Agreement Units recognized in Other, net for 2013, 2012 and 2011:

	2013	2012	2011
Net unrealized gains (losses) on decommissioning trust funds	$ 146	$ 105	$ (4)
Net realized gains (losses) on sale of decommissioning trust funds	$ 24	$ 51	$ (10)

Effective Income Tax Rate.

Generation's effective income tax rates for the years ended December 31, 2013, 2012 and 2011 were 36.7%, 47.3% and 37.4%, respectively. See Note 14 of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

Results of Operations—ComEd

	2013	2012	Favorable (Unfavorable) 2013 vs. 2012 Variance	2011	Favorable (Unfavorable) 2012 vs. 2011 Variance
Operating revenues	$ 4,464	$ 5,443	$ (979)	$ 6,056	$ (613)
Purchased power expense	1,174	2,307	1,133	3,035	728
Revenues net of purchased power expense (a)	3,290	3,136	154	3,021	115
Other operating expenses					
Operating and maintenance	1,368	1,345	(23)	1,189	(156)
Depreciation and amortization	669	610	(59)	554	(56)
Taxes other than income	299	295	(4)	296	1
Total other operating expenses	2,336	2,250	(86)	2,039	(211)
Operating income	954	886	68	982	(96)
Other income and (deductions)					
Interest expense, net	(579)	(307)	(272)	(345)	38
Other, net	26	39	(13)	29	10
Total other income and (deductions)	(553)	(268)	(285)	(316)	48
Income before income taxes	401	618	(217)	666	(48)
Income taxes	152	239	87	250	11
Net income	$ 249	$ 379	$ (130)	$ 416	$ (37)

(a) ComEd evaluates its operating performance using the measure of revenues net of purchased power expense. ComEd believes that revenues 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 revenues net of purchased power expense below as a complement to the financial information provided in accordance with GAAP. However, revenues 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

Year Ended December 31, 2013, Compared to Year Ended December 31, 2012. ComEd's net income for the year ended December 31, 2013, was lower than the same period in 2012, primarily due to the remeasurement of Exelon's like-kind exchange tax position, partially offset by increased electric distribution revenues, including the impacts of Senate Bill 9, and increased transmission revenues. See Note 3 – Regulatory Matters and Note 14 – Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

Year Ended December 31, 2012, Compared to Year Ended December 31, 2011. ComEd's net income for the year ended December 31, 2012, was lower than the same period in 2011, primarily due to increased operating and maintenance expenses, partially offset by increased electric distribution revenues and increased transmission revenues.

Operating Revenues Net of Purchased Power Expense

There are certain drivers of operating revenues that are fully offset by their impact on purchased power expense, such as commodity procurement costs and participation in customer choice programs. ComEd is permitted to recover electricity procurement costs from retail customers without mark-up. Therefore, fluctuations in electricity procurement costs have no impact on revenues net of purchased power expense. See Note 3 – Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on ComEd's electricity procurement process.

All ComEd customers have the choice to purchase electricity from a competitive electric generation supplier. Customer choice programs do not impact ComEd's volume of deliveries, but do affect ComEd's operating revenues related to supplied energy, which is fully offset in purchased power expense. Therefore, customer choice programs have no impact on revenues net of purchased power expense.

The number of retail customers participating in customer choice programs was 2,630,185, 1,627,150 and 380,262 at December 31, 2013, 2012 and 2011, respectively, representing 68%, 43% and 10% of total retail customers, respectively. Retail energy purchased from competitive electric generation suppliers represented 81%, 65% and 56% of ComEd's retail kWh sales for the years ended December 31, 2013, 2012 and 2011, respectively. During 2012, the City of Chicago and approximately 240 Illinois municipalities, including governmental entities such as townships and counties, approved referenda regarding electric supply aggregation. The referenda allowed governmental officials to identify and sign contracts with competitive electric generation suppliers on behalf of the eligible retail customers in the community, while also allowing customers to opt-out of the municipal aggregation program. As of December 31, 2013, there are approximately 330 municipalities that have approved a municipal aggregation referendum in the ComEd service territory. As a result, approximately 69% of residential usage as of December 31, 2013 is being supplied by competitive electric generation suppliers, and ComEd estimates that over 80% of that usage resulted from municipal aggregation activities.

The changes in ComEd's revenues net of purchased power expense for the year ended 2013 compared to the same period in 2012 consisted of the following:

	Increase (Decrease)
Weather	$ (17)
Volume	(2)
Electric distribution revenues, including impacts of Senate Bill 9	168
Discrete impacts of the 2012 Distribution Rate Case Order	13
Transmission revenues	14
Regulatory required programs	20
Uncollectible accounts recovery, net	(58)
Other	16
Total increase	$ 154

Weather. 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. Conversely, mild weather reduces demand. For the year ended December 31, 2013, the increase in revenues net of purchased power expense was offset by unfavorable weather conditions as a result of the mild weather in 2013, compared to the same period in 2012.

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 with cooling degree days generally having a more significant impact to ComEd, particularly during the summer months. The changes in heating and cooling degree days in ComEd's service territory for the years ended December 31, 2013 and 2012 consisted of the following:

Heating and Cooling Degree-Days				% Change	
Twelve Months Ended December 31,	2013	2012	Normal	From 2012	From Normal
Heating Degree-Days	6,603	5,065	6,341	30.4 %	4.1 %
Cooling Degree-Days	933	1,324	842	(29.5)%	10.8 %

Volume. Revenues net of purchased power expense decreased as a result of lower delivery volume, exclusive of the effects of weather, for the year ended December 31, 2013, reflecting decreased average usage per residential customer as compared to the same period in 2012.

Electric Distribution Revenues. EIMA provides for a performance-based formula rate tariff, which requires 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. Distribution revenues vary from year to year based upon fluctuations in the underlying costs, investments being recovered and other billing determinants. During the year ended December 31, 2013, ComEd recorded increased revenues of $168 million, primarily due to increased capital investments, increased operating expenses, and higher allowed return on common equity, including the impacts of Senate Bill 9. These amounts exclude the discrete impacts of the 2012 Distribution Rate Case Orders, discussed separately below. See Note 3 – Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Discrete Impacts of the 2012 Distribution Rate Case Orders. On October 3, 2012, the ICC issued its final order related to ComEd's 2011 formula rate proceeding under EIMA (Rehearing Order), which reestablished ComEd's position on the return on its pension asset, resulting in an increase to revenues in 2013. See Note 3 – Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Transmission Revenues. 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 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. During the year ended December 31, 2013, ComEd recorded increased revenues of $14 million primarily due to increased capital investments and higher operating expenses. See Note 3 – Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Regulatory Required Programs. Revenues related to regulatory required programs are recoveries from customers for costs of various legislative and 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. See the operating and maintenance expense discussion below for additional information on included programs.

Uncollectible Accounts Recovery, Net. Represents recoveries under ComEd's uncollectible accounts tariff. See the operating and maintenance expense discussion below for additional information on this tariff.

Other. 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. Other revenues were higher during the year ended December 31, 2013, compared to the same period in 2012, primarily due to recoveries of increased environmental costs associated with MGP sites, for which an equal and offsetting amount expense is reflected in depreciation and amortization expense during the periods presented.

The changes in ComEd's revenues net of purchased power expense for 2012 compared to 2011 consisted of the following:

	Increase (Decrease)
Weather	$ 2
Volume	(4)
Electric distribution revenues	53
Discrete impacts of the 2012 Distribution Rate Case Order	(13)

Transmission revenues		40
Regulatory required programs		32
Uncollectible accounts recovery, net		(28)
Other		33
Total increase	$	115

Weather. For the year ended December 31, 2012, revenues net of purchased power expense increased due to favorable weather conditions in 2012 compared to the same period in 2011.

The changes in heating and cooling degree days in ComEd's service territory for the years ended December 31, 2012 and 2011 consisted of the following:

Heating and Cooling Degree-Days				**% Change**	
Twelve Months Ended December 31,	**2012**	**2011**	**Normal**	**From 2011**	**From Normal**
Heating Degree-Days	5,065	6,134	6,341	(17.4)%	(20.1)%
Cooling Degree-Days	1,324	1,036	842	27.8 %	57.2 %

Volume. Revenues net of purchased power expense decreased as a result of lower delivery volume, exclusive of the effects of weather, for the year ended December 31, 2012, reflecting decreased average usage per residential customer as compared to the same period in 2011.

Electric Distribution Revenues. Under EIMA, ComEd recorded increased revenues during the year ended December 31, 2012 of $53 million, primarily due to increased capital investments and increased operating expenses, partially offset by lower allowed return on common equity. These amounts exclude the discrete impacts of the 2012 Distribution Rate Case Orders discussed separately below. See Note 3 – Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Discrete Impacts of the 2012 Distribution Rate Case Orders. The May and October 2012 ICC Distribution Rate Case Orders resulted in a reduction to revenues of $13 million in 2012 compared to the same period in 2011. See Note 3 – Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Transmission Revenues. Based on the FERC-approved formula, ComEd recorded increased revenues during the year ended December 31, 2012 of $40 million, primarily due to increased operating expenses. See Note 3 – Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Operating and Maintenance Expense

	Year Ended December 31,		**Increase**	**Year Ended December 31,**		**Increase**
	2013	**2012**	**2013 vs. 2012**	**2012**	**2011**	**2012 vs. 2011**
Operating and maintenance expense - baseline	$ 1,202	$ 1,199	$ 3	$ 1,199	$ 1,075	$ 124
Operating and maintenance expense - regulatory required programs(a)	166	146	20	146	114	32
Total operating and maintenance expense	$ 1,368	$ 1,345	$ 23	$ 1,345	$ 1,189	$ 156

____

(a) Operating and maintenance expense for regulatory required programs are recoveries from customers for costs of various legislative and regulatory programs 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 year ended December 31, 2013, compared to the same period in 2012 and changes for the year ended December 31, 2012, compared to the same period in 2011, consisted of the following:

	Increase (Decrease) 2013 vs. 2012	Increase (Decrease) 2012 vs. 2011
Baseline		
Labor, other benefits, contracting and materials(a)	$ 48	$ 95
Pension and non-pension postretirement benefits expense	3	46
Discrete impacts from 2010 Rate Case order(b)	—	32
Storm-related costs	(10)	(1)
Science and Technology Innovation Trust (c)	—	(11)
Uncollectible accounts expense - provision(d)	(10)	(14)
Uncollectible accounts expense - recovery, net(d)	(48)	(14)
Other	20	(9)
	3	124
Regulatory required programs		
Energy efficiency and demand response programs	20	33
Purchased power administrative costs	—	(1)
	20	32
Increase in operating and maintenance expense	$ 23	$ 156

(a) The increase includes contracting costs resulting from new projects associated with EIMA for the years ended December 31, 2013 and 2012. See Note 3 – Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information regarding EIMA.
(b) ComEd recorded one-time net benefits in May 2012 as a result of the 2010 Rate Case order to reestablish previously expensed plant balances and to recover previously incurred costs related to Exelon's 2009 restructuring plan.
(c) Under EIMA, ComEd makes recurring payments for contribution to a Science and Technology Innovation Trust fund that will be used to fund energy innovation.
(d) ComEd is allowed to recover from or refund to customers the difference between the utility's annual uncollectible accounts expense and the amounts collected in rates annually through a rider mechanism. In 2013, ComEd recorded a net reduction in operating and maintenance expense related to uncollectible accounts due to the timing of regulatory cost recovery and customers purchasing electricity from competitive electric generation suppliers as a result of municipal aggregation. An equal and offsetting reduction has been recognized in operating revenues for the periods presented.

Depreciation and Amortization Expense

The changes in depreciation and amortization expense for 2013 compared to 2012 and 2012 compared to 2011, consisted of the following:

	Increase 2013 vs. 2012	Increase 2012 vs. 2011
Depreciation associated with higher plant balances	$ 22	$ 22
Amortization of storm-related regulatory assets(a)	4	4
Amortization of MGP regulatory assets(b)	27	8
Amortization of other regulatory assets	6	6
Other	—	16

Increase in depreciation and amortization expense	$ 59	$ 56

(a) Under EIMA, ComEd is required to recover costs associated with significant storms over a five-year period through the amortization of a regulatory asset.
(b) An equal and offsetting amount for the amortization expense related to MGP remediation expenditures is reflected in operating revenues during the periods presented.

Taxes Other Than Income

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. Taxes other than income, which can vary period to period, include municipal and state utility taxes, real estate taxes, and payroll taxes. Taxes other than income increased primarily due to increased Illinois electricity distribution taxes.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. Taxes other than income taxes decreased primarily due to decreased Illinois electricity distribution taxes.

Interest Expense, Net

The changes in interest expense, net for 2013 compared to 2012 and 2012 compared to 2011 consisted of the following:

	Increase (Decrease) 2013 vs. 2012	Increase (Decrease) 2012 vs. 2011
Interest expense related to uncertain tax positions(a)	$ 281	$ —
Interest expense on debt (including financing trusts)	2	(26)
Other	(11)	(12)
Increase (decrease) in interest expense, net	$ 272	$ (38)

(a) Primarily reflects the remeasurement of Exelon's like-kind exchange tax position in the first quarter of 2013. See Note 14 – Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

Other, Net

The changes in other, net for 2013 compared to 2012 and 2012 compared to 2011 consisted of the following:

	Increase (Decrease) 2013 vs. 2012	Increase (Decrease) 2012 vs. 2011
Interest income related to uncertain tax positions(a)	$ (20)	$ 16
Gain on asset disposal	5	—
Other	2	(6)
Increase in Other, net	$ (13)	$ 10

(a) Primarily reflects a receivable recorded in the fourth quarter of 2012 related to the final 1999-2001 IRS settlement.

Effective Income Tax Rate

ComEd's effective income tax rates for the years ended December 31, 2013, 2012 and 2011, were 37.9%, 38.7% and 37.5%, respectively. See Note 14 – Income Taxes of the Combined Notes to

Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

Retail Deliveries to customers (in GWhs)	2013	2012	% Change 2013 vs 2012	Weather-Normal % Change	2011	% Change 2012 vs 2011	Weather-Normal % Change
Retail Deliveries (a)							
Residential	27,800	28,528	(2.6)%	(0.6)%	28,273	0.9%	(0.6)%
Small commercial & industrial	32,305	32,534	(0.7)%	0.2%	32,281	0.8%	0.2%
Large commercial & industrial	27,684	27,643	0.1%	(0.3)%	27,732	(0.3)%	(0.3)%
Public authorities & electric railroads	1,355	1,272	6.5%	4.2%	1,235	3.0%	4.2%
Total Retail Deliveries	89,144	89,977	(0.9)%	(0.1)%	89,521	0.5%	(0.1)%

Number of Electric Customers	As of December 31, 2013	2012	2011
Residential	3,480,398	3,455,546	3,448,481
Small commercial & industrial	367,569	365,357	365,824
Large commercial & industrial	1,984	1,980	2,032
Public authorities & electric railroads	4,853	4,812	4,797
Total	3,854,804	3,827,695	3,821,134

Electric Revenue	2013	2012	% Change 2013 vs 2012	2011	% Change 2012 vs 2011
Retail Sales (a)					
Residential	$2,073	$3,037	(31.7)%	$3,510	(13.5)%
Small commercial & industrial	1,250	1,339	(6.6)%	1,517	(11.7)%
Large commercial & industrial	427	395	8.1%	383	3.1%
Public authorities & electric railroads	48	44	9.1%	50	(12.0)%
Total Retail Sales	3,798	4,815	(21.1)%	5,460	(11.8)%
Other Revenue (b)	666	628	6.1%	596	5.4%
Total Electric Revenues	$4,464	$5,443	(18.0)%	$6,056	(10.1)%

(a) Reflects delivery revenues and volumes from customers purchasing electricity directly from ComEd and customers purchasing electricity from a competitive electric generation supplier, as all customers are assessed delivery charges. 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 wholesale revenue, rental revenue, revenues related to late payment charges, assistance provided to other utilities through mutual assistance programs, recoveries of environmental remediation costs associated with MGP sites, and intercompany revenues.

Results of Operations—PECO

	2013	2012	Favorable (unfavorable) 2013 vs. 2012 variance	2011	Favorable (unfavorable) 2012 vs. 2011 variance
Operating revenues	$ 3,100	$ 3,186	$ (86)	$ 3,720	$ (534)
Purchased power and fuel	1,300	1,375	75	1,864	489

Revenues net of purchased power and fuel expense [(a)]	1,800	1,811	(11)	1,856	(45)
Other operating expenses					
Operating and maintenance	748	809	61	794	(15)
Depreciation and amortization	228	217	(11)	202	(15)
Taxes other than income	158	162	4	205	43
Total other operating expenses	1,134	1,188	54	1,201	13
Operating income	666	623	43	655	(32)
Other income and (deductions)					
Interest expense, net	(115)	(123)	8	(134)	11
Other, net	6	8	(2)	14	(6)
Total other income and (deductions)	(109)	(115)	6	(120)	5
Income before income taxes	557	508	49	535	(27)
Income taxes	162	127	(35)	146	19
Net income	395	381	14	389	(8)
Preferred security dividends	7	4	3	4	—
Net income on common stock	$ 388	$ 377	$ 11	$ 385	$ (8)

(a) PECO evaluates its operating performance using the measures of revenues net of purchased power expense for electric sales and revenue net of fuel expense for gas sales. PECO believes revenues net of purchased power expense and revenues net of fuel expense are useful measurements of its performance because they provide information that can be used to evaluate its net revenues from operations. PECO has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, revenues 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

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The increase in net income was driven primarily by lower operating and maintenance expense partially offset by an increase in income taxes.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The decrease in net income was driven primarily by lower operating revenues net of purchased power and fuel expense and increased storm costs. The decrease in revenues net of purchased power and fuel expense was primarily related to unfavorable weather and a decline in electric load. The decrease to net income was partially offset by lower taxes other than income, interest expense and income taxes.

Operating Revenues Net of Purchased Power and Fuel Expense

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 revenues 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 revenues collected from customers related to supplied energy and natural gas service. Customer choice program activity has no impact on electric and gas revenues net of purchase power and fuel expense. The number of retail customers purchasing energy from a competitive electric generation supplier was 531,500, 496,500, and 387,600 at December 31, 2013, 2012 and 2011, respectively. Retail deliveries purchased from competitive electric generation suppliers represented 68%, 66%, and 57% of PECO's retail kWh sales for the years ended December 31, 2013, 2012 and 2011, respectively. The number of retail customers purchasing natural gas from a competitive natural gas supplier was 66,400, 53,600, and 24,800 at December 31, 2013, 2012 and 2011, respectively. Retail deliveries purchased from competitive natural gas suppliers represented 19%, 16%, and 11% of PECO's mmcf sales for the years ended December 31, 2013, 2012 and 2011, respectively.

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

	Increase (Decrease)		
	Electric	**Gas**	**Total**
Weather	$ 6	$ 31	$ 37
Volume	(3)	(3)	(6)
Pricing	(14)	2	(12)
Regulatory required programs	(6)	—	(6)
Gross receipts tax	(8)	—	(8)
Gas distribution tax repair	—	(8)	(8)
Other	(7)	(1)	(8)
Total decrease	$ (32)	$ 21	$ (11)

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 2013 winter weather conditions.

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 year ended December 31, 2013 compared to the same period in 2012 and normal weather consisted of the following:

				% Change	
Heating and Cooling Degree-Days	**2013**	**2012**	**Normal**	**From 2012**	**From Normal**
Twelve Months Ended December 31,					
Heating Degree-Days	4,474	3,747	4,603	19.4%	(2.8)%
Cooling Degree-Days	1,411	1,603	1,301	(12.0)%	8.5%

Volume

The decrease in electric revenues net of purchased power expense related to delivery volume, exclusive of the effects of weather, reflects the impact of energy efficiency initiatives on customer usages as well as a shift in the volume profile across classes from higher priced classes to lower priced classes, partially offset by the oil refineries returning to full production in 2013 as well as moderate economic growth. The decrease in gas revenues net of fuel expense related to delivery volume, exclusive of the effects of weather, primarily reflects a decline in Residential use per customer.

Pricing

The decrease in electric operating revenues net of purchased power expense as a result of pricing is primarily attributable to lower overall effective rates due to increased usage across all major customer classes.

Regulatory Required Programs

This represents the change in operating revenues collected under approved riders to recover costs incurred for the smart meter, energy efficiency and consumer education programs as well as the administrative costs for the GSA and AEPS programs. The riders are designed to provide full and current cost recovery as well as a return. The offsetting 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.

Gross Receipts Tax

GRT is an excise tax on total electric revenues. As a result of decreases in operating revenues compared to 2012, GRT decreased. Equal and offsetting decreases in GRT have been reflected in taxes other than income.

Gas Distribution Tax Repair

The decrease in gas distribution tax repair reflects the 2012 tax benefit received from prior period gas distribution repairs for the 2011 tax year. There is an equal and offsetting tax benefit in operating revenues, see NOTE 3 — Regulatory Matters for further explanation.

Other

The decrease in other electric revenues net of purchased power expense compared to the year ended December 31, 2012 reflects a decrease in wholesale transmission revenues earned by PECO due to higher peak loads in the previous years.

The changes in PECO's operating revenues net of purchased power and fuel expense for the year ended December 31, 2012 compared to the same period in 2011 consisted of the following:

	Increase (Decrease)		
	Electric	**Gas**	**Total**
Weather	$ (17)	$ (15)	$ (32)
Volume	(22)	—	(22)
Pricing	(4)	3	(1)
Regulatory required programs	29	—	29
Gross receipts tax	(27)	—	(27)
Other	8	—	8
Total increase (decrease)	$ (33)	$ (12)	$ (45)

Weather

Electric and gas revenues net of purchased power and fuel expense were lower due to unfavorable winter weather conditions during 2012 in PECO's service territory.

The changes in heating and cooling degree days in PECO's service territory for the year ended December 31, 2012 compared to the same period in 2011 and normal weather consisted of the following:

				% Change	
Heating and Cooling Degree-Days (a)	**2012**	**2011**	**Normal**	**From 2011**	**From Normal**
Twelve Months Ended December 31,					
Heating Degree-Days	3,747	4,157	4,603	(9.9)%	(18.6)%
Cooling Degree-Days	1,603	1,617	1,301	(0.9)%	23.2%

Volume

The decrease in electric revenues net of purchased power expense related to delivery volume, exclusive of the effects of weather, reflected the reduced oil refinery load in PECO's service territory and the impact of energy efficiency initiatives and weak economic conditions on customer usage. See Note 3 of the Combined Notes to Consolidated Financial Statements for further information regarding energy efficiency initiatives.

Pricing

The decrease in electric operating revenues net of purchased power expense as a result of pricing is primarily attributable to lower overall effective rates due to increased usage across all major customer classes.

Regulatory Required Programs

This represents the change in operating revenues collected under approved riders to recover costs incurred for the smart meter, energy efficiency and consumer education programs as well as the administrative costs for the GSA and AEPS programs. The riders are designed to provide full and current cost recovery as well as a return. The offsetting 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 primarily reflected a decrease in GRT revenues as a result of lower supplied energy service and a reduction in the GRT rate. There is an equal and offsetting decrease in GRT expense included in taxes other than income.

Operating and Maintenance Expense

	Twelve Months Ended December 31,		Increase (Decrease)	Twelve Months Ended December 31,		Increase (Decrease)
	2013	**2012**	**2013 vs. 2012**	**2012**	**2011**	**2012 vs. 2011**

Operating and Maintenance Expense - Baseline	$ 668	$ 723	$ (55)	$ 723	$ 725	$ (2)
Operating and Maintenance Expense - Regulatory Required Programs(a)	80	86	(6)	86	69	17
Total Operating and Maintenance Expense	$ 748	$ 809	$ (61)	$ 809	$ 794	$ 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 2013 compared to 2012 and 2012 compared to 2011 consisted of the following:

	Increase (Decrease) 2013 vs. 2012	Increase (Decrease) 2012 vs. 2011
Baseline		
Labor, other benefits, contracting and materials	$ 10	$ (29)
Storm-related costs	(49)	9 [(a)]
Pension and non-pension postretirement benefits expense	(12)	—
Constellation merger and integration costs	(8)	15
Other	4	3
	(55)	(2)
Regulatory Required Programs		
Smart Meter	4	12
Energy Efficiency	(9)	8
GSA	—	(1)
Consumer education program	(1)	(1)
AEPS	—	(1)
	(6)	17
Increase (decrease) in operating and maintenance expense	$ (61)	$ 15

(a) Storm-related costs include $46 million of incremental storm costs incurred in the fourth quarter of 2012 as a result of Hurricane Sandy. This expense was significantly offset by the costs incurred related to Hurricane Irene and other storms throughout 2011.

Depreciation and Amortization Expense

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The increase in depreciation and amortization expense, net for 2013, compared to 2012 was primarily due to ongoing capital expenditures.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The increase in depreciation and amortization expense, net for 2012 compared to 2011 was primarily due to ongoing capital expenditures.

Taxes Other Than Income

The change in taxes other than income for 2013 compared to 2012 and 2012 compared to 2011 consisted of the following:

	Increase (Decrease) 2013 vs. 2012	Increase (Decrease) 2012 vs. 2011
GRT expense	$ (12)	$ (33)
Sales and use tax	8	(12)[a]
Other	—	2
Decrease in taxes other than income	$ (4)	$ (43)

(a) The decrease reflects a sales and use tax reserve adjustment in the first quarter of 2012 resulting from the completion of the audit of tax years 2005 through 2010.

Interest Expense, Net

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The decrease in interest expense, net for 2013 compared to 2012 was primarily due to refinancing debt at lower interest rates during the second half of 2012.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The decrease in interest expense, net for 2012 compared to 2011 was primarily due to the debt retirement in November 2011.

Other, Net

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. Other, net remained relatively level between periods.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The decrease in Other, net for 2012 compared to 2011 was due to decreased AFUDC - Equity. See Note 20 of the Combined Notes to Consolidated Financial Statements in the 2012 10-K for additional details of the components of Other, net.

Effective Income Tax Rate

PECO's effective income tax rates for the years ended December 31, 2013, 2012 and 2011 were 29.1%, 25.0% and 27.3%, respectively. The increase in effective income tax rate in 2013 compared 2012 reflects the 2012 impact of the tax benefit received from electing to change the method of accounting for gas distribution property for the 2011 tax year. See Note 14 of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

PECO Electric Operating Statistics and Revenue Detail

Retail Deliveries to customers (in GWhs)	2013	2012	% Change 2013 vs. 2012	Weather-Normal % Change	2011	% Change 2012 vs. 2011	Weather-Normal % Change
Retail Deliveries (a)							
Residential	13,341	13,233	0.8%	(0.0)%	13,687	(3.3)%	(1.7)%

Small commercial & industrial	8,101	8,063	0.5%	(1.1)%	8,321	(3.1)%	(2.3)%
Large commercial & industrial	15,379	15,253	0.8%	1.5%	15,677	(2.7)%	(2.7)%
Public authorities & electric railroads	930	943	(1.4)%	(1.4)%	945	(0.2)%	(0.2)%
Total Electric Retail Deliveries	37,751	37,492	0.7%	0.3%	38,630	(2.9)%	(2.2)%

	As of December 31,		
Number of Electric Customers	**2013**	**2012**	**2011**
Residential	1,423,068	1,417,773	1,415,681
Small commercial & industrial	149,117	148,803	148,570
Large commercial & industrial	3,105	3,111	3,110
Public authorities & electric railroads	9,668	9,660	9,689
Total	1,584,958	1,579,347	1,577,050

Electric Revenue	**2013**	**2012**	**% Change 2013 vs. 2012**	**2011**	**% Change 2012 vs. 2011**
Retail Sales (a)					
Residential	$1,592	$1,689	(5.7)%	$1,934	(12.7)%
Small commercial & industrial	433	462	(6.3)%	585	(21.0)%
Large commercial & industrial	224	232	(3.4)%	308	(24.7)%
Public authorities & electric railroads	30	31	(3.2)%	38	(18.4)%
Total Retail	2,279	2,414	(5.6)%	2,865	(15.7)%
Other Revenue (b)	221	226	(2.2)%	244	(7.4)%
Total Electric Revenues	$2,500	$2,640	(5.3)%	$3,109	(15.1)%

(a) Reflects delivery volumes and revenues from customers purchasing electricity directly from PECO and customers purchasing electricity 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 Operating Statistics and Revenue Detail

Deliveries to customers (in mmcf)	**2013**	**2012**	**% Change 2013 vs. 2012**	**Weather-Normal % Change**	**2011**	**% Change 2012 vs. 2011**	**Weather-Normal % Change**
Retail Deliveries (b)							
Retail sales	57,613	49,767	15.8%	(0.1)%	54,239	(8.2)%	(0.1)%
Transportation and other	28,089	26,687	5.3%	0.5%	28,204	(5.4)%	(4.8)%
Total Gas Deliveries	85,702	76,454	12.1%	0.1%	82,443	(7.3)%	(1.6)%

	As of December 31,		
Number of Gas Customers	**2013**	**2012**	**2011**
Residential	458,356	454,502	451,382
Commercial & industrial	42,174	41,836	41,373
Total Retail	500,530	496,338	492,755
Transportation	909	903	879
Total	501,439	497,241	493,634

Gas revenue	2013	2012	% Change 2013 vs. 2012	2011	% Change 2012 vs. 2011
Retail Sales (a)					
Retail sales	$562	$509	10.4%	$576	(11.6)%
Transportation and other	38	37	2.7%	35	5.7%
Total Gas Revenues	$600	$546	9.9%	$611	(10.6)%

(a) Reflects delivery volumes and revenues from customers purchasing natural gas directly from PECO and customers purchasing natural gas from a competitive natural gas supplier as all customers are assessed distribution charges. For customers purchasing natural gas from PECO, revenue also reflects the cost of natural gas.

Results of Operations—BGE

	2013	2012	Favorable (unfavorable) 2013 vs. 2012 variance	2011
Operating revenues	$ 3,065	$ 2,735	$ 330	$ 3,068
Purchased power and fuel expense	1,421	1,369	(52)	1,593
Revenue net of purchased power and fuel expense (a)	1,644	1,366	278	1,475
Other operating expenses				
Operating and maintenance	634	728	94	680
Depreciation and amortization	348	298	(50)	274
Taxes other than income	213	208	(5)	207
Total other operating expenses	1,195	1,234	39	1,161
Operating income	449	132	317	314
Other income and (deductions)				
Interest expense, net	(122)	(144)	22	(129)
Other, net	17	23	(6)	26
Total other income and (deductions)	(105)	(121)	16	(103)
Income before income taxes	344	11	333	211
Income taxes	134	7	(127)	75
Net income	210	4	206	136
Preference stock dividends	13	13	—	13
Net income (loss) attributable to common shareholder	$ 197	$ (9)	$ 206	$ 123

(a) BGE evaluates its operating performance using the measures of revenues net of purchased power expense for electric sales and revenues net of fuel expense for gas sales. BGE believes revenues 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 revenues from operations. BGE has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, revenues 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

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The increase in net income was driven primarily by higher distribution rates as a result of the 2012 rate order issued by

MDPSC and decreased operating revenues 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. Additionally, the increase in net income was also driven by higher 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 and lower storm restoration costs in 2013.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The decrease in net income was driven primarily by decreased operating revenues net of purchased power and fuel expense related to the residential customer rate credit provided as a condition of the MDPSC's approval of Exelon's merger with Constellation. The decrease in net income was also driven by increased operating and maintenance expenses, 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 as well as merger transaction costs, and increased depreciation and amortization expense. None of the customer rate credit, the charitable contributions, or the transaction costs are recoverable from BGE's customers.

Operating Revenues Net of 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.

The number of customers electing to select a competitive electric generation 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 generation supplier. This customer choice of electric generation 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 generation supplier was 399,000, 362,000 and 314,000 at December 31, 2013, 2012 and 2011, respectively, representing 32%, 29% and 25% of total retail customers, respectively. Retail deliveries purchased from competitive electric generation suppliers represented 61%, 60% and 58% of BGE's retail kWh sales for the years ended December 31, 2013, 2012 and 2011, respectively. The number of retail customers purchasing natural gas from a competitive natural gas supplier was 172,000, 143,000 and 118,000 at December 31, 2013, 2012 and 2011, respectively, representing 26%, 22% and 18% of total retail customers, respectively. Retail deliveries purchased from competitive natural gas suppliers represented 54%, 56% and 52% of BGE's retail mmcf sales for the years ended December 31, 2013, 2012 and 2011, respectively.

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

	Increase (Decrease)		
	Electric	Gas	Total
2012 Residential customer rate credit (a)	$ 82	$ 31	$ 113
Pricing	69	24	93
Regulatory program cost recovery	36	6	42
Other	26	4	30
Total increase	$ 213	$ 65	$ 278

(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 allows BGE to recognize revenues at MDPSC-approved levels per customer, regardless of what BGE's 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 impacted customers in subsequent months for the difference between approved revenue levels under revenue decoupling and actual customer billings.

Heating and cooling 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 year ended December 31, 2013 compared to the same period in 2012 and normal weather consisted of the following:

				% Change	
Heating and Cooling Degree-Days	**2013**	**2012**	**Normal**	**From 2012**	**From Normal**
Twelve Months Ended December 31,					
Heating Degree-Days	4,744	3,960	4,661	19.8%	1.8%
Cooling Degree-Days	869	1,022	864	(15.0)%	0.6%

2012 Residential Customer Rate Credit.

The increase in operating revenues net of purchased power and fuel expense for the year ended December 31, 2013 compared to the same period in 2012 was due to the residential customer rate credit provided in 2012 as a result of the MDPSC's order approving Exelon's merger with Constellation.

Pricing.

The increase in operating revenues net of purchased power and fuel expense as a result of pricing for the year ended December 31, 2013 compared to the same period in 2012 was primarily due to the impact of the new electric and natural gas distribution rates charged to customers that became effective Feburary 23, 2013 and December 13, 2013 in accordance with the MDPSC approved electric and natural gas distribution rate case order. See Note 3 – Regulatory Matters of the Combined Notes to the Consolidated Financial Statements for further information.

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 year ended December 31, 2013 compared to the same period in 2012 was due to the recovery of higher energy efficiency program costs.

Other.

Other revenues increased during the year ended December 31, 2013 compared to the same period in 2012. Other revenues, which can vary from period to period, include miscellaneous revenues such as service application and late payment fees.

The changes in BGE's operating revenues net of purchased power and fuel expense for the year ended December 31, 2012 compared to the same period in 2011 consisted of the following:

	Increase (Decrease)		
	Electric	Gas	Total
2012 Residential customer rate credit	$ (82)	$ (31)	$ (113)
Commodity margin	(1)	(5)	(6)
Regulatory program cost recovery	15	4	19
Transmission	11	-	11
Other	(13)	(7)	(20)
Total decrease	$ (70)	$ (39)	$ (109)

The changes in heating and cooling degree days for the twelve months ended 2012 and 2011, consisted of the following:

				% Change	
Heating and Cooling Degree-Days (a)	2012	2011	Normal	From 2011	From Normal
Twelve Months Ended December 31,					
Heating Degree-Days	3,960	4,326	4,711	(8.5)%	(15.9)%
Cooling Degree-Days	1,022	1,035	858	(1.3)%	19.1%

2012 Residential Customer Rate Credit

The residential customer rate credit provided as a result of the MDPSC's order approving Exelon's merger with Constellation decreased operating revenues net of purchased power and fuel expense for the year ended December 31, 2012.

Commodity Margin

The commodity margin for both electric and gas revenues decreased during the year ended December 31, 2012 compared to the same period in 2011 due to an increase in the number of customers using competitive suppliers in 2012.

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 year ended December 31, 2012 compared to the same period in 2011 was due to the recovery of higher energy efficiency programs costs.

Transmission

Transmission revenues increased during the year ended December 31, 2012 compared to the same period in 2011 due to higher revenue requirements. BGE's transmission rates are established based on a FERC-approved formula. The rates also include transmission investment incentives approved by FERC in a number of orders covering various new transmission investment projects since 2007.

Other

Other revenues decreased during the year ended December 31, 2012 compared to the same period in 2011. Other revenues, which can vary from period to period, include miscellaneous revenues such as service application and late payment fees.

Operating and Maintenance Expense

The changes in operating and maintenance expense for 2013 compared to 2012 and 2012 compared to 2011 consisted of the following:

	Increase (Decrease) 2013 vs. 2012	Increase (Decrease) 2012 vs. 2011
Charitable contributions (a)	$ (28)	$ 28
Storm costs deferral(b)	—	16
Storm-related costs (c)	(62)	7
Pension and non-pension postretirement benefits expense	—	6
Labor, other benefits, contracting and materials	20	(10)
Merger transaction costs(a)	(21)	(9)
Other	(3)	10
(Decrease) Increase in operating and maintenance expense	$ (94)	$ 48

(a) During the first quarter of 2012, BGE accrued $28 million in charitable contributions as a result of BGE's merger-related commitments. The charitable contribution accrual and merger costs are not recoverable from BGE's customers.

(b) During the first quarter of 2011, the MDPSC issued a comprehensive rate order permitting the deferral of incremental distribution service restoration expenses associated with 2010 storms as a regulatory asset.

(c) On June 29, 2012, a "Derecho" storm caused extensive damage to BGE's electric distribution system and created power outages that lasted multiple days. As a result, BGE incurred $62 million of incremental costs during the year ended December 31, 2012, of which $20 million are capital costs. In the fourth quarter of 2012, BGE incurred $38 million of incremental costs as a result of Hurricane Sandy, of which $14 million are capital costs. These amounts compare to $40 million of incremental expenses incurred during the third quarter of 2011 associated with Hurricane Irene, of which $25 million are capital costs, and $14 million of incremental expenses, of which $3 are capital costs, incurred during the first quarter of 2011.

Depreciation and Amortization Expense

The changes in depreciation and amortization expense for 2013 compared to 2012 and 2012 compared to 2011 consisted of the following:

	Increase (Decrease) 2013 vs. 2012	Increase (Decrease) 2012 vs. 2011
Depreciation expense (a)	$ 18	$ 20
Regulatory asset amortization (b)	31	6
Other	1	(2)

Increase in depreciation and amortization expense	$ 50	$ 24

(a) Deprecation and amortization expense increased due to higher plant balances year over year.
(b) Regulatory asset amortization increased due to higher energy efficiency and demand response programs expenditures year over year

Taxes Other Than Income

The change in taxes other than income for 2013 compared to 2012 and 2012 compared to 2011 consisted of the following:

	Increase (Decrease) 2013 vs. 2012	Increase (Decrease) 2012 vs. 2011
Property tax	$ (2)	$ 4
Franchise tax	7	(1)
Other	—	(2)
Increase in taxes other than income	$ 5	$ 1

Interest Expense, Net

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The decrease in interest expense, net for 2013 compared to 2012 was primarily due to the interest recorded in 2012 on prior year tax liabilities and lower effective interest rates as a result of the refinancing of debt at a lower interest rate in 2013.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The increase in interest expense, net in 2012 compared to 2011 was primarily due to higher outstanding debt balances and interest recorded in 2012 on prior year tax liabilities.

Effective Income Tax Rate

BGE's effective income tax rates for the years ended December 31, 2013, 2012 and 2011 were 39.0%, 63.6% and 35.5%, respectively. See Note 14 of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

BGE Electric Operating Statistics and Revenue Detail

Retail Deliveries to customers (in GWhs)	2013	2012	% Change 2013 vs. 2012	Weather-Normal % Change	2011	% Change 2012 vs. 2011	Weather-Normal % Change
Retail Deliveries (a)							
Residential	13,077	12,719	2.8%	n.m.	12,652	0.5%	n.m.
Small commercial & industrial (c)	3,035	2,990	1.5%	n.m.	3,023	(1.1)%	n.m.
Large commercial & industrial (c)	14,339	14,956	(4.1)%	n.m.	15,729	(4.9)%	n.m.
Public authorities & electric railroads	317	329	(3.6)%	n.m.	405	(18.8)%	n.m.
Total Electric Retail Deliveries	30,768	30,994	(0.7)%	n.m.	31,809	(2.6)%	n.m.

Number of Electric Customers	As of December 31, 2013	2012	2011

Residential	1,120,431	1,116,233	1,116,401
Small commercial & industrial (c)	112,850	112,994	113,026
Large commercial & industrial (c)	11,652	11,580	11,365
Public authorities & electric railroads	292	319	326
Total	1,245,225	1,241,126	1,241,118

Electric Revenue	2013	2012	% Change 2013 vs. 2012	2011	% Change 2012 vs. 2011
Retail Sales (a)					
Residential	$1,404	$1,274	10.2%	$1,456	(12.5)%
Small commercial & industrial (c)	257	248	3.6%	268	(7.5)%
Large commercial & industrial (c)	439	393	11.7%	416	(5.5)%
Public authorities & electric railroads	31	30	3.3%	29	3.4%
Total Retail	2,131	1,945	9.6%	2,169	(10.3)%
Other Revenue (b)	274	238	15.1%	152	56.6%
Total Electric Revenues	$2,405	$2,183	10.2%	$2,321	(5.9)%

(a) Reflects delivery revenues and volumes from customers purchasing electricity directly from BGE and customers purchasing electricity 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.

(b) Other revenue includes wholesale transmission revenue and late payment charges.

(c) Certain commercial and industrial (C&I) customers were reclassified from small C&I to large C&I in prior years to conform to the current year's classification of C&I customers.

BGE Gas Operating Statistics and Revenue Detail

Deliveries to customers (in mmcf)	2013	2012	% Change 2013 vs. 2012	Weather-Normal % Change	2011	% Change 2012 vs. 2011	Weather-Normal % Change
Retail Deliveries (d)							
Retail sales	94,020	86,946	8.1%	n.m.	94,800	(8.3)%	n.m.
Transportation and other (e)	12,210	15,751	(22.5)%	n.m.	16,436	(4.2)%	n.m.
Total Gas Deliveries	106,230	102,697	3.4%	n.m.	111,236	(7.7)%	n.m.

Number of Gas Customers	As of December 31, 2013	2012	2011
Residential	611,532	610,827	608,943
Commercial & industrial	44,162	44,228	44,211
Total	655,694	655,055	653,154

Gas revenue	2013	2012	% Change 2013 vs. 2012	2011	% Change 2012 vs. 2011
Retail Sales (d)					
Retail sales	$592	$494	19.8%	$580	(14.8)%
Transportation and other (e)	68	58	17.2%	92	(37.0)%
Total Gas Revenues	$660	$552	19.6%	$672	(17.9)%

(d) Reflects delivery revenues and volumes from customers purchasing natural gas directly from BGE and customers purchasing natural gas 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 BGE.

(e) Transportation and other gas revenue includes off-system revenue of 12,210 mmcfs ($55 million), 15,751 mmcfs ($51 million), and 16,436 mmcfs ($82 million) for the years ended 2013, 2012 and 2011, respectively.

Liquidity and Capital Resources

Exelon's and Generation's 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 December 31, 2012. Exelon's and Generation's activity for 2011 is unadjusted for the effects of the merger. BGE's prior year activity presented below includes its activity for the 12 months ended December 31, 2012 and 2011.

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 are in place until 2018. In addition, Generation has $0.4 billion in bilateral facilities with banks which expire 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 to 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 13 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 3 and 22 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 approximately $264 million to its pension plans in 2014, of which Generation, ComEd, PECO and BGE expect to contribute $118 million, $119 million, $11 million and $0 million, respectively. See Note 16 of the Combined Notes to Consolidated Financial Statements for the Registrants' 2013 and 2012 pension contributions.

Unlike the qualified pension plans, Exelon's other postretirement plans are not subject to regulatory minimum contribution requirements. Management considers several factors in determining the level of contributions to Exelon's other postretirement benefit plans, including levels of benefit claims paid and regulatory implications (amounts deemed prudent to meet regulatory expectations and best assure continued recovery). Exelon expects to contribute approximately $430 million to the other postretirement benefit plans in 2014, of which Generation, ComEd, PECO and BGE expect to contribute $168 million, $197 million, $19 million and $17 million, respectively. See Note 16 of the Combined Notes to Consolidated Financial Statements for the Registrants' 2013 and 2012 other postretirement benefit contributions.

See the "Contractual Obligations" section below for management's estimated future pension and other postretirement benefits contributions.

Tax Matters

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

- Exelon, Generation, ComEd, PECO and BGE expect to receive tax refunds of approximately $380 million, $60 million, $320 million, $10 million and $20 million, respectively, between 2014 and 2015.

- 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.

- In September 2012, PECO filed an application with the IRS to change its method of accounting for gas distribution repairs for the 2011 tax year. The newly adopted method results in a cash tax benefit in 2012 of approximately $38 million and $41 million at Exelon and PECO, respectively. Exelon currently anticipates that the IRS will issue industry guidance in the near future. See Note 3 of the Combined Notes to Consolidated Financial Statements for discussion regarding the regulatory treatment of PECO's tax benefits from the application of the method change.

The following table provides a summary of the major items affecting Exelon's cash flows from operations for the years ended December 31, 2013, 2012 and 2011:

	2013	2012	2013 vs. 2012 Variance	2011	2012 vs. 2011 Variance
Net income	$ 1,729	$ 1,171	$ 558	$ 2,499	$ (1,328)
Add (subtract):					
Non-cash operating activities (a)	4,159	5,588	(1,429)	4,848	740
Pension and non-pension postretirement benefit contributions	(422)	(462)	40	(2,360)	1,898
Income taxes	883	544	339	492	52
Changes in working capital and other noncurrent assets and liabilities (b)	(185)	(731)	546	(279)	(452)
Option premiums paid, net	(36)	(114)	78	(3)	(111)
Counterparty collateral received (paid), net	215	135	80	(344)	479
Net cash flows provided by operations	$ 6,343	$ 6,131	$ 212	$ 4,853	$ 1,278

(a) Represents depreciation, amortization, depletion and accretion, net fair value changes related to derivatives, deferred income taxes, provision for uncollectible accounts, pension and non-pension postretirement benefit expense, equity in earnings and losses of unconsolidated affiliates and investments, decommissioning-related items, stock compensation expense, impairment of long-lived assets, 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 2013, 2012 and 2011 by Registrant were as follows:

	2013	2012	2011
Exelon [(a)]	$ 6,343	$ 6,131	$ 4,853
Generation [(a)]	3,887	3,581	3,313
ComEd	1,218	1,334	836
PECO	747	878	818
BGE [(a)]	561	485	476

(a) Exelon's and Generation's prior year activity includes the activity of Constellation, and BGE in the case of Exelon, from the merger effective date of March 12, 2012 through December 31, 2012. Exelon's and Generation's activity for 2011 is unadjusted for the effects of the merger. BGE's prior year activity includes its activity for the 12 months ended December 31, 2012 and 2011.

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 2013, 2012 and 2011 were as follows:

Generation

- During 2013, 2012 and 2011, Generation had net (payments) receipts of counterparty collateral of $162 million, $95 million and $(410) million, respectively. Net payments during 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 2013, 2012 and 2011, Generation's accounts receivable from ComEd increased (decreased) by $(16) million, $(15) million and $12 million, respectively, primarily due to changes in receivables for energy purchases related to its SFC, ICC-approved RFP contracts and financial swap contract.

- During 2013, 2012 and 2011, Generation's accounts receivable from PECO increased (decreased) by $(17) million, $17 million and $(210) million, respectively.

- During 2013, 2012 and 2011, Generation's accounts receivable from BGE increased (decreased) by $(4) million, $23 million and $(13) million, respectively.

- During 2013, 2012 and 2011, Generation had net payments of approximately $36 million, $114 million and $3 million, respectively, related to purchases and sales of options. The level of option activity in a given year may vary due to several factors, including changes in market conditions as well as changes in hedging strategy.

ComEd

- During 2013, 2012 and 2011, ComEd's net payables to Generation for energy purchases related to its supplier forward contract, ICC-approved RFP contracts and financial swap contract settlements increased (decreased) by $(16) million, $(15) million and $12 million, respectively. During 2013, 2012 and 2011, ComEd's payables to other energy suppliers for energy purchases increased (decreased) by $35 million, $20 million and $(43) million, respectively.

- During 2013, 2012, and 2012, ComEd received $53 million, $37 million and $63 million, respectively, of incremental cash collateral from PJM due to variations in its energy transmission activity levels. As of December 31, 2013 and December 31, 2012, ComEd had cash collateral remaining at PJM of $0M and $53 million, respectively.

PECO

- During 2013, 2012 and 2011, PECO's payables to Generation for energy purchases increased (decreased) by $(17) million, $17 million and $(210) million, respectively, and payables to other energy suppliers for energy purchases increased (decreased) by $33 million, $(22) million and $97 million, respectively.

BGE

- During 2013, 2012 and 2011, BGE's payables to Generation for energy purchases increased (decreased) by $(4) million, $23 million and $(13) million, respectively, and payables to other energy suppliers for energy purchases increased (decreased) by $5 million, $40 million and $(60) million, respectively.

Cash Flows from Investing Activities

Cash flows used in investing activities for 2013, 2012, and 2011 by Registrant were as follows:

	2013	2012	2011
Exelon [(a) (c) (f)]	$ (5,394)	$ (4,576)	$ (4,603)
Generation [(a) (c) (f)]	(2,916)	(2,629)	(3,077)
ComEd	(1,387)	(1,212)	(1,007)
PECO	(531)	(328)	(557)
BGE [(f)]	(571)	(573)	(592)

Capital expenditures by Registrant for 2013, 2012 and 2011 and projected amounts for 2014 are as follows:

	Projected 2014 (b)	2013	2012	2011 (a)
Exelon [f]	$ 5,475	$ 5,395	$ 5,789	$ 4,042
Generation [c] [f]	2,400	2,752	3,554	2,491
ComEd [d]	1,775	1,433	1,246	1,028
PECO	625	537	422	481
BGE [f]	600	587	582	592
Other [e]	75	86	82	42

(a) Includes $387 million in 2011 related to acquisitions, principally acquisition of Wolf Hollow, Antelope Valley and Shooting Star. See Note 4 of the Combined Notes to Consolidated Financial Statements for additional information.
(b) Total projected capital expenditures do not include adjustments for non-cash activity.
(c) Includes nuclear fuel.
(d) 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 expects to file an updated investment plan with the ICC in April, 2014.
(e) Other primarily consists of corporate operations and BSC.
(f) Exelon's and Generation's prior year activity includes the activity of Constellation, and BGE in the case of Exelon, from the merger effective date of March 12, 2012 through December 31, 2012. Exelon's and Generation's activity for 2011 is unadjusted for the effects of the merger. BGE's prior year activity includes its activity for the 12 months ended December 31, 2012 and 2011.

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

Generation

Approximately 38% and 11% of the projected 2014 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 2014 capital expenditures are a portion of the costs of a series of planned power uprates across Generation's nuclear fleet. See "EXELON CORPORATION — Executive Overview," for more information on nuclear uprates.

On November 30, 2012, a subsidiary of Generation sold three Maryland generating stations and associated assets to Raven Power Holdings LLC, a subsidiary of Riverstone Holdings LLC, and received net proceeds of approximately $371. In addition, Generation will begin to make cash payments of approximately $31 million to Raven Power Holdings LLC over a twelve-month period beginning in June 2014. In 2012, Generation incurred transaction costs of approximately $15 million through the date of closing of the transaction. The sale will generate approximately $195 million of cash tax benefits, of which $155 million will be realized in periods through 2014 with the balance to be received in later years. Therefore, Generation expects net after-tax cash sale proceeds of approximately $495 million through 2014 and approximately $36 million in subsequent years.

ComEd, PECO and BGE

Approximately 91%, 72% and 89% of the projected 2014 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 include smart grid/smart meter technology required under EIMA. PECO and BGE capital expenditures include investments related to their respective 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. See Notes 3 and 7 of the Combined Notes to Consolidated Financial Statements for additional information.

In 2010, NERC provided guidance to transmission owners, including ComEd, PECO, and BGE, that recommends the completion of performance assessments of 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 2014. ComEd, PECO and BGE will incur 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 2014 capital expenditures above reflect capital spending for remediation to be completed in 2014.

ComEd, PECO and BGE anticipate that they will fund capital expenditures with internally generated funds and borrowings, including ComEd's capital expenditures associated with EIMA as further discussed in Note 3 of the Combined Notes to Consolidated Financial Statements.

Cash Flows from Financing Activities

Cash flows provided by (used in) financing activities for 2013, 2012 and 2011 by Registrant were as follows:

	2013	2012	2011
Exelon	$ (826)	$ (1,085)	$ (846)
Generation	(384)	(777)	(196)
ComEd	61	(212)	355
PECO	(361)	(382)	(589)
BGE	(48)	128	115

Debt. Debt activity for 2013, 2012 and 2011 by Registrant was as follows:

Company	Issuances of long-term debt in 2013	Use of proceeds
Generation	$5 million of variable rate CEU Credit Agreement project financing, due July 22, 2016	Used to fund Upstream gas activities
Generation	$227 million of fixed rate DOE Project Financing, due January 5, 2037	Used for Antelope Valley solar development
Generation	$1 million of 2.93% Social Security Administration Project Financing, due February 18, 2015	Used to install conservation measures for the Social Security Administration Headquarters facility in Maryland
Generation	$9 million of 4.40% Energy Efficiency Financing, due August 31, 2014	Used for funding to install energy conservation measures in Beckley, West Virginia
Generation	$613 million of 6.00% Continental Wind Senior Secured Notes, due February 28, 2033	Used for general corporate purposes

ComEd	$350 million of First Mortgage 4.60% Bonds, Series 114, due August 15, 2043	Used to repay outstanding commercial paper obligations and for general corporate purposes
PECO	$300 million of First and Refunding Mortgage 1.20% Bonds due October 15, 2016	Used to pay at maturity first and refunding mortgage bonds due October 15, 2013 and other general corporate purposes
PECO	$250 million of First and Refunding Mortgage 4.80% Bonds due October 15, 2043	Used to pay at maturity first and refunding mortgage bonds due October 15, 2013 and other general corporate purposes
BGE	$300 million of fixed rate 3.35% Notes due July 1, 2023	Used to partially refinance Notes due July 1, 2013 and for general corporate purposes

Company	Issuances of long-term debt in 2012	Use of proceeds
Generation	$78 million of variable rate CEU Credit Agreement project financing, due July 16, 2016	Used to fund Upstream gas activities
Generation	$220 million of fixed rate DOE Project Financing, due January 5, 2037	Used for Antelope Valley solar development
Generation	$523 million of 4.25% Senior Notes due June 15, 2022	Used for general corporate purposes and issued in connection with the Exchange Offer
Generation	$788 million of 5.60% Senior Notes due June 15, 2042	Used for general corporate purposes and issued in connection with the Exchange Offer
Generation	$38 million of variable rate Clean Horizons project financing due June 7, 2030	Used for funding for Maryland solar development
ComEd	$350 million of First Mortgage 3.80% Bonds, Series 113, due October 1, 2042	Used to repay outstanding commercial paper obligations and for general corporate purposes
PECO	$350 million of First and Refunding Mortgage 2.38% Bonds due September 15, 2022	Used to pay at maturity First Mortgage Bonds due October 1, 2012 and for general corporate purposes
BGE	$250 million of fixed rate 2.80% Notes due August 15, 2022	Used to repay total outstanding commercial paper obligations and for general corporate purposes

Company	Issuances of long-term debt in 2011	Use of proceeds
ComEd	$600 million of First Mortgage 1.625% Bonds, Series 110, due January 15, 2014	Used as an interim source of liquidity for a January 2011 contribution to Exelon-sponsored pension plans

ComEd	$250 million of First Mortgage 1.95% Bonds, Series 111, due September 1, 2016	Used to retire $191 million tax-exempt variable-rate First Mortgage Bonds, Series 2008 D, E, and F, $345 million of First Mortgage Bonds, Series 105, and for other general corporate purposes
ComEd	$350 million of First Mortgage 3.40% Bonds, Series 112, due September 1, 2021	Used to retire $191 million tax-exempt variable-rate First Mortgage Bonds, Series 2008 D, E, and F, $345 million of First Mortgage Bonds, Series 105, and for other general corporate purposes
BGE	$300 million of fixed rate 3.50% Notes, due November 15, 2021	Used to repay total outstanding commercial paper obligations and for general corporate purposes

Company	Retirement of long-term debt in 2013
Generation	$3 million scheduled payments of 7.83% Kennett Square capital lease until September 1, 2020
Generation	$113 million of variable rate Solar Revolver project financing with a final maturity of July 7, 2014
Generation	$2 million of 2.563% project financing Clean Horizons with a final maturity of September 7, 2030
Generation	$2 million of 2.68% Sacramento Energy Loan Agreement with a final maturity of December 31, 2030
Generation (a)	$450 million of 8.625% Series A Junior Subordinated Debentures with a final maturity of June 15, 2063
ComEd	$125 million of 7.625% First Mortgage Bonds, Series 92, due April 15, 2013
ComEd	$127 million of 7.500% First Mortgage Bonds, Series 94, due July 1, 2013
PECO	$300 million of 5.600% First and Refunding Mortgage Bonds, due October 15, 2013
BGE	$67 million of 5.72% fixed rate Rate Stabilization Bonds, due April 1, 2017
BGE	$400 million of 6.125% Senior Notes, due July 1, 2013

Company	Retirement of long-term debt in 2012
Exelon	$2 million of 7.30% fixed-rate Medium Term Notes with a maturity date of June 1, 2012
Exelon	$442 million of 7.60% fixed-rate Senior Notes with a maturity date of April 1, 2032
Generation	$2 million scheduled payments of 7.83% Kennett Square capital lease until September 20, 2020
Generation	$46 million of 3-year term rate Armstrong Co. 2009 A, Pollution Control Notes at 5.00% with a final maturity of December 1, 2042
Generation	$89 million of variable rate project financing CEU Credit Agreement with a final maturity of July 16, 2016

Generation	$17 million of variable rate Solar Revolver project financing with a final maturity of July 7, 2014
Generation	$75 million of variable rate MEDCO tax-exempt bonds with a final maturity of April 1, 2024
Generation	$2 million of variable rate Sacramento Solar Promissory Note with a final maturity of March 12, 2012
ComEd	$450 million of 6.15% First Mortgage Bonds, Series 98, due March 15, 2012
PECO	$225 million of 4.75% First and Refunding Mortgage Bonds, due October 1, 2012
PECO	$150 million of 4.00% First and Refunding Mortgage Bonds, due December 1, 2012
BGE	$8 million of 5.72% fixed rate Rate Stabilization Bonds, due April 1, 2016
BGE	$55 million of 5.47% fixed rate Rate Stabilization Bonds, due October 1, 2012
BGE	$110 million of variable rate Medium Term Notes, due June 15, 2012

Company	Retirement of long-term debt in 2011
Generation	$2 million scheduled payments of 7.83% Kennett Square capital lease until September 20, 2020
ComEd	$2 million of 4.75% sinking fund debentures, due December 1, 2011
ComEd	$50 million of tax-exempt variable-rate First Mortgage Bonds, Series 2008 D, due March 1, 2020
ComEd	$50 million of tax-exempt variable-rate First Mortgage Bonds, Series 2008 E, due May 1, 2021
ComEd	$91 million of tax-exempt variable-rate First Mortgage Bonds, Series 2008 F, due March 1, 2017
ComEd	$345 million of 5.40% First Mortgage Bonds, Series 105, due December 15, 2011
PECO	$250 million of 5.95% First and Refunding Mortgage Bonds, due November 1, 2011
BGE	$60 million of 5.47% fixed rate Rate Stabilization Bonds, due October 1, 2012

(a) Represents debt obligations assumed by Exelon as part of the merger on March 12, 2012 that became callable at face value on June 15, 2013. Exelon and subsidiaries of Generation (former Constellation subsidiaries) assumed intercompany loan agreements that mirror the terms and amounts of the third-party debt obligations of Exelon, resulting in intercompany notes payable as of December 31, 2012 included in long-term debt to affiliate on Generation's Consolidated Balance Sheets and notes receivable from affiliates at Exelon Corporate, which are eliminated in consolidation on Exelon's Consolidated Balance Sheets. The third-party debt obligations were reported in Long-term Debt on Exelon's Consolidated Balance Sheets as of December 31, 2012. The debentures were redeemed and the intercompany loan agreements repaid on June 15, 2013.

From time to time and as market conditions warrant, the Registrants may engage in long-term debt retirements via tender offers, open market repurchases or other viable options to reduce debt on their respective balance sheets.

Dividends. Cash dividend payments and distributions during 2013, 2012 and 2011 by Registrant were as follows:

	2013	2012	2011
Exelon	$ 1,263	$ 1,733	$ 1,397
Generation	625	1,626	172

ComEd	220	105	300
PECO	333	347	352
BGE	13	13	98 (a)

(a) Dividends on common stock for $85 million were paid to Constellation for the year ended December 31, 2011.

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.

Second Quarter 2013 Dividend

On April 23, 2013, the Exelon board of directors declared a regular quarterly dividend, paid on June 10, 2013 of $0.310 per share on Exelon's common stock.

Third Quarter 2013 Dividend

On July 23, 2013, the Exelon board of directors declared a regular quarterly dividend, paid on September 10, 2013 of $0.310 per share on Exelon's common stock.

Fourth Quarter 2013 Dividend

On October 22, 2013, the Exelon board of directors declared a regular quarterly dividend, paid on December 10, 2013 of $0.310 per share on Exelon's common stock

First Quarter 2014 Dividend

On January 28, 2014, the Exelon Board of Directors declared a first quarter 2014 regular quarterly dividend of $0.31 per share on Exelon's common stock payable on March 10, 2014, to shareholders of record of Exelon at the end of the day on February 14, 2014.

Short-Term Borrowings. Short-term borrowings incurred (repaid) during 2013, 2012 and 2011 by Registrant were as follows:

	2013	2012	2011
Generation	$ 13	$ (52)	$ —
ComEd	184	—	—
BGE	135	—	—
Other (a)	—	(140)	161
Exelon	$ 332	$ (192)	$ 161

(a) Other primarily consists of corporate operations and BSC.

Retirement of Long-Term Debt to Financing Affiliates. There were no retirements of long-term debt to financing affiliates during 2013, 2012 and 2011 by the Registrants.

Contributions from Parent/Member. Contributions from Parent/Member (Exelon) during 2013, 2012 and 2011 by Registrant were as follows:

2013	2012	2011

Generation	$ 26	$ 48	$ 30
ComEd [(a)]	176	11	11
PECO	27	9	18
BGE	—	66	—

(a) In 2013, represents indemnification from Exelon in relation to the like-kind exchange transaction.

Other. Other significant financing activities for Exelon for 2013, 2012 and 2011 were as follows:

- Exelon received proceeds from employee stock plans of $47 million, $72 million and $38 million during 2013, 2012 and 2011, respectively.

Credit Matters

Market Conditions

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 $6.6 billion was available as of December 31, 2013, and of which no financial institution has more than 8% of the aggregate commitments for Exelon, Generation, ComEd, PECO and BGE. The Registrants had access to the commercial paper market during 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 for further information regarding the effects of uncertainty in the capital and credit markets.

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 December 31, 2013, it would have been required to provide incremental collateral of $2.0 billion 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, which is well within its current available credit facility capacities of $4.3 billion. If ComEd lost its investment grade credit ratings as of December 31, 2013, it would have been required to provide incremental collateral of $6 million, which is well within its current available credit facility capacity of $816 million, which takes into account commercial paper borrowings as of December 31, 2013. If PECO lost its investment grade credit rating as of December 31, 2013 it would not be required to provide collateral pursuant to PJM's credit policy and could have been required to provide collateral of $42 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 December 31, 2013, it would have been required to provide collateral of $2 million pursuant to PJM's credit policy and could have been required to provide collateral of $85 million related to its natural gas procurement contracts, which, in the aggregate, are well within BGE's current available credit facility capacity of $465 million.

Exelon Credit Facilities

See Note 13 of the Combined Notes to Consolidated Financial Statements for discussion of the Registrants' credit facilities and short term borrowing activity.

Other Credit Matters

Capital Structure. At December 31, 2013, the capital structures of the Registrants consisted of the following:

	Exelon	Generation	ComEd	PECO	BGE
Long-term debt	44 %	30 %	42 %	40 %	42 %
Long-term debt to affiliates [(a)]	2 %	8 %	2 %	4 %	5 %
Common equity	53 %	—	55 %	56 %	49 %
Member's equity	—	62 %	—	—	—
Preference Stock	—	—	—	—	4 %
Commercial paper and notes payable	1 %	—	1 %	—	—

(a) Includes approximately $648 million, $206 million, $184 million and $258 million owed to unconsolidated affiliates of Exelon, ComEd, PECO and BGE respectively. These special purpose entities were created for the sole purposes of issuing mandatorily redeemable trust preferred securities of ComEd, PECO and BGE. See Note 2 of the Combined Notes to Consolidated Financial Statements for additional information regarding the authoritative guidance for VIEs.

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 participants during the year ended December 31, 2013, in addition to the net contribution or borrowing as of December 31, 2013, are presented in the following table:

	Maximum Contributed	Maximum Borrowed	December 31, 2013 Contributed (Borrowed)
Generation	$ 159	$ 435	$ 44
PECO	304	—	—
BSC	—	287	(223)
Exelon Corporate	237	—	179

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 15 — Asset Retirement Obligations 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. The Registrants maintain a combined shelf registration statement unlimited in amount, with the SEC. The ability of each Registrant to sell securities off the 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. The issuance by ComEd, PECO and BGE of long-term debt or equity securities requires the prior authorization of the ICC, PAPUC and MDPSC, respectively. ComEd, PECO and BGE normally obtain the required approvals on a periodic basis to cover their anticipated financing needs for a period of time or in connection with a specific financing. 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 December 31, 2013, ComEd had $1.3 billion available in long-term debt refinancing authority and $218 million available in new money long-term debt financing authority from the ICC. During the fourth quarter of 2013, ComEd requested and received $1 billion in new money financing authority from the ICC. The authority is effective on January 1, 2014 and expires January 1, 2017. As of December 31, 2013, PECO had $1.4 billion available in long-term debt financing authority from the PAPUC. As of December 31, 2013, BGE had $850 million available in long-term financing authority from MDPSC.

FERC has financing jurisdiction over ComEd's, PECO's and BGE's short-term financings and all of Generation's financings. As of December 31, 2013, ComEd, PECO had BGE had short-term financing authority from FERC, which expires on December 31, 2015, of $2.5 billion, $2.5 billion and $700 million, respectively. Generation currently has blanket financing authority it received from FERC in connection with its market-based rate authority. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information.

Exelon's ability to pay dividends on its common stock depends on the receipt of dividends paid by its operating subsidiaries. The payments of dividends to Exelon by its subsidiaries in turn depend on their results of operations and cash flows and other items affecting retained earnings. The Federal Power Act declares it to be unlawful for any officer or director of any public utility "to participate in the making or paying of any dividends of such public utility from any funds properly included in capital account." In addition, under Illinois law, ComEd may not pay any dividend on its stock, unless, among other things, its earnings and earned surplus are sufficient to declare and pay a dividend after provision is made for reasonable and proper reserves, or unless ComEd has specific authorization from the ICC. BGE is subject to certain dividend restrictions established by the MDPSC. First, BGE is prohibited from paying a dividend on its common shares through the end of 2014. Second, BGE is prohibited from paying a dividend on its common shares if (a) after the dividend payment, BGE's equity ratio would be below 48% as calculated pursuant to the MDPSC's ratemaking precedents or (b) BGE's senior unsecured credit rating is rated by two of the three major credit rating agencies below investment grade. Finally, BGE must notify the MDPSC that it intends to declare a dividend on its common shares at least 30 days before such a dividend is paid. There are no other limitations on BGE paying common stock dividends unless: (1) BGE elects to defer interest payments on the 6.20% Deferrable Interest Subordinated Debentures due 2043, and any deferred interest remains unpaid; or (2) any dividends (and any redemption payments) due on BGE's preference stock have not been paid. At December 31, 2013, Exelon had retained earnings of $10,358 million, including Generation's undistributed earnings of $3,613 million, ComEd's retained earnings of $750 million consisting of retained earnings appropriated for future dividends of $2,389 million partially offset by $1,639 million of unappropriated retained deficit, PECO's retained earnings of $649 million and BGE's retained earnings $1,005 million. See Note 22 of the Combined Notes to Consolidated Financial Statements for additional information regarding fund transfer restrictions.

Contractual Obligations

The following tables summarize the Registrants' future estimated cash payments as of December 31, 2013 under existing contractual obligations, including payments due by period. See Note 22 of the Combined Notes to Consolidated Financial Statements for information regarding the Registrants' commercial and other commitments, representing commitments potentially triggered by future events.

Exelon

	Payment due within				
		2015-	2017-	Due 2019	All

	Total	2014	2016	2018	and beyond	Other
Long-term debt [(a)]	$ 19,367	$ 1,424	$ 2,953	$ 2,731	$ 12,259	$ —
Interest payments on long-term debt [(b)]	12,845	925	1,692	1,396	8,832	—
Liability and interest for uncertain tax positions [(c)]	1,255	—	—	—	—	1,255
Capital leases	41	4	8	10	19	—
Operating leases [(d)]	826	103	180	145	398	—
Purchase power obligations [(e)]	3,046	1,378	852	367	449	—
Fuel purchase agreements [(f)]	9,606	1,520	2,622	1,967	3,497	—
Electric supply procurement [(f)]	1,880	1,062	678	140	—	—
AEC purchase commitments [(f)]	6	1	2	2	1	—
Curtailment services commitments [(f)]	132	45	74	13	—	—
Long-term renewable energy and REC commitments [(g)]	1,589	72	150	160	1,207	—
PJM regional transmission expansion commitments (h)	1,019	208	597	214	—	—
Spent nuclear fuel obligation	1,021	—	—	—	1,021	—
Pension minimum funding requirement [(i)]	1,223	264	444	426	89	—
Total contractual obligations	$ 53,856	$ 7,006	$ 10,252	$ 7,571	$ 27,772	$ 1,255

(a) Includes $648 million due after 2016 to ComEd, PECO and BGE financing trusts.

(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2013 and do not reflect anticipated future refinancing, early redemptions or debt issuances. Variable rate interest obligations are estimated based on rates as of December 31, 2013. Includes estimated interest payments due to ComEd, PECO and BGE financing trusts.

(c) As of December 31, 2013, Exelon's liability for uncertain tax positions and related interest payable was $906 million and $349 million, respectively. Exelon was unable to reasonably estimate the timing of liability and interest payments and receipts in individual years beyond 12 months due to uncertainties in the timing of the effective settlement of tax positions. Exelon has other unrecognized tax positions that were not recorded on the Consolidated Balance Sheet in accordance with authoritative guidance. See Note 14 of the Combined Notes to Consolidated Financial Statements for further information regarding unrecognized tax positions.

(d) Excludes PPAs and other capacity contracts that are accounted for as operating leases. These amounts are included within purchase power obligations. Includes estimated cash payments for service fees related to PECO's meter reading operating lease.

(e) Purchase power obligations include PPAs and other capacity contracts including those that are accounted for as operating leases. Amounts presented represent Generation's expected payments under these arrangements at December 31, 2013, including those related to CENG. Expected payments include certain fixed capacity charges which may be reduced based on plant availability. Expected payments exclude renewable PPA contracts that are contingent in nature. These obligations do not include ComEd's SFCs as these contracts do not require purchases of fixed or minimum quantities. See Notes 3 and 22 of the Combined Notes to Consolidated Financial Statements.

(f) Represents commitments to purchase nuclear fuel, natural gas and related transportation, storage capacity and services, procure electric supply, and purchase AECs and curtailment services. See Note 22 of the Combined Notes to Consolidated Financial Statements for electric and gas purchase commitments.

(g) ComEd entered into 20-year contracts for renewable energy and RECs beginning in June 2012. ComEd is permitted to recover its renewable energy and REC costs from retail customers with no mark-up. The annual commitments represent the maximum settlements with suppliers for renewable energy and RECs under the existing contract terms. Pursuant to the ICC's December 19, 2012 order, ComEd's commitments under the existing long-term contracts were reduced for the June 2013 through May 2014 procurement period. The ICC's December 18, 2013 order approved the reduction of ComEd's commitments under the long-term contracts for the June 2014 through May 2015 procurement period, however the amount of the reduction will not be finalized and approved by the ICC until March 2014. See Note 3 of Combined Notes to Consolidated Financial Statements for additional information.

(h) Under their operating agreements with PJM, ComEd, PECO and BGE are committed to the construction of transmission facilities to maintain system reliability. These amounts represent ComEd's, PECO's and BGE's expected portion of the costs to pay for the completion of the required construction projects. See Note 3 of Combined Notes to Consolidated Financial Statements for additional information.

(i) These amounts represent Exelon's estimated minimum pension contributions to its qualified plans required under ERISA and the Pension Protection Act of 2006, as well as contributions necessary to avoid benefit restrictions and at-risk status. For Exelon's largest qualified pension plan, the projected contributions reflect a funding strategy of contributing the greater of $250 million or the minimum amounts under ERISA to avoid benefit restrictions and at-risk status. These amounts represent estimates that are based on assumptions that are subject to change. The minimum required contributions for years after 2019 are not included. See Note 16 of the Combined Notes to Consolidated Financial Statements for further information regarding estimated future pension benefit payments.

Generation

	Total	Payment due within 2014	2015-2016	2017-2018	Due 2019 and beyond	All Other
Long-term debt	$ 7,519	$ 557	$ 628	$ 701	$ 5,633	$ —
Interest payments on long-term debt [a]	5,362	368	693	625	3,676	—
Liability and interest for uncertain tax benefits [b]	264	—	—	—	—	264
Capital leases	33	4	8	10	11	—
Operating leases [c]	571	49	98	88	336	—
Purchase power obligations [d]	3,046	1,378	852	367	449	—
Fuel purchase agreements [e]	8,490	1,212	2,296	1,807	3,175	—
Spent nuclear fuel obligation	1,021	—	—	—	1,021	—
Total contractual obligations	$ 26,306	$ 3,568	$ 4,575	$ 3,598	$ 14,301	$ 264

(a) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2013 and do not reflect anticipated future refinancing, early redemptions or debt issuances. Variable rate interest obligations are estimated based on rates as of December 31, 2013.
(b) As of December 31, 2013, Generation's liability for uncertain tax positions and related interest payable was $227 million and $37 million, respectively. Generation was unable to reasonably estimate the timing of liability and interest payments in individual years beyond 12 months due to uncertainties in the timing of the effective settlement of tax positions.
(c) Excludes PPAs and other capacity contracts that are accounted for as operating leases. These amounts are included within purchase power obligations.
(d) Purchase power obligations include PPAs and other capacity contracts including those that are accounted for as operating leases. Amounts presented represent Generation's expected payments under these arrangements at December 31, 2013. Expected payments include certain fixed capacity charges which may be reduced based on plant availability. Expected payments exclude renewable PPA contracts that are contingent in nature. See Note 22 of the Combined Notes to Consolidated Financial Statements.
(e) See Note 22 of the Combined Notes to Consolidated Financial Statements for further information regarding fuel purchase agreements.

ComEd

	Total	Payment due within 2014	2015-2016	2017-2018	Due 2019 and beyond	All Other
Long-term debt[a]	$ 5,892	$ 617	$ 925	$ 1,265	$ 3,085	$ —
Interest payments on long-term debt [b]	3,704	274	515	393	2,522	—
Liability and interest for uncertain tax positions [c]	498	—	—	—	—	498
Capital leases	8	—	—	—	8	—
Operating leases	47	13	22	9	3	—
Electric supply procurement	736	323	273	140	—	—
Long-term renewable energy and associated REC commitments [d]	1,589	72	150	160	1,207	—
PJM regional transmission expansion commitments (e)	486	134	350	2	—	—
Total contractual obligations	$ 12,960	$ 1,433	$ 2,235	$ 1,969	$ 6,825	$ 498

(a) Includes $206 million due after 2017 to a ComEd financing trust.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2013 and do not reflect anticipated future refinancing, early redemptions or debt issuances. Variable rate interest obligations are estimated based on rates as of December 31, 2013. Includes estimated interest payments due to the ComEd financing trust.
(c) As of December 31, 2013, ComEd's liability for uncertain tax positions and related interest payable was $324 million and $174 million, respectively. ComEd was unable to reasonably estimate the timing of liability and interest payments in individual years beyond 12 months due to uncertainties in the timing of the effective settlement of tax positions.

(d) ComEd entered into 20-year contracts for renewable energy and RECs beginning in June 2012. ComEd is permitted to recover its renewable energy and REC costs from retail customers with no mark-up. The annual commitments represent the maximum settlements with suppliers for renewable energy and RECs under the existing contract terms. Pursuant to the ICC's December 19, 2012 order, ComEd's commitments under the existing long-term contracts were reduced for the June 2013 through May 2014 procurement period. The ICC's December 18, 2013 order approved the reduction of ComEd's commitments under the long-term contracts for the June 2014 through May 2015 procurement period, however the amount of the reduction will not be finalized and approved by the ICC until March 2014. See Note 3 of Combined Notes to Consolidated Financial Statements for additional information.
(e) Under its operating agreement with PJM, ComEd is committed to the construction of transmission facilities to maintain system reliability. These amounts represent ComEd's expected portion of the costs to pay for the completion of the required construction projects. See Note 3 of Combined Notes to Consolidated Financial Statements for additional information.

PECO

		Payment due within				
	Total	2014	2015-2016	2017-2018	Due 2019 and beyond	All Other
Long-term debt [(a)]	$ 2,384	$ 250	$ 300	$ 500	$ 1,334	$ —
Interest payments on long-term debt [(b)]	1,505	104	189	160	1,052	—
Operating leases	25	13	6	6	—	—
Fuel purchase agreements [(c)]	507	179	210	52	66	—
Electric supply procurement [(c)]	681	590	91	—	—	—
AEC purchase commitments [(c)]	14	2	4	4	4	—
PJM regional transmission expansion commitments (d)	133	32	69	32	—	—
Total contractual obligations	$ 5,249	$ 1,170	$ 869	$ 754	$ 2,456	$ —

(a) Includes $184 million due after 2017 to PECO financing trusts.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2013 and do not reflect anticipated future refinancing, early redemptions or debt issuances.
(c) Represents commitments to purchase natural gas and related transportation, storage capacity and services, procure electric supply, and purchase AECs. See Note 22 of the Combined Notes to Consolidated Financial Statements for additional information.
(d) Under its operating agreement with PJM, PECO is committed to the construction of transmission facilities to maintain system reliability. These amounts represent PECO's expected portion of the costs to pay for the completion of the required construction projects. See Note 3 of Combined Notes to Consolidated Financial Statements for additional information.

BGE

		Payment due within				
	Total	2014	2015-2016	2017-2018	Due 2019 and beyond	All Other
Long-term debt [(a)]	$ 2,273	$ —	$ 300	$ 265	$ 1,708	$ —
Interest payments on long-term debt [(b)]	1,608	112	220	162	1,114	—
Operating leases	61	12	20	15	14	—
Fuel purchase agreements [(c)]	609	129	116	108	256	—
Electric supply procurement [(c)]	1,256	783	473	—	—	—
Curtailment services commitments [(c)]	132	45	74	13	—	—
PJM regional transmission expansion commitments (d)	400	42	178	180	—	—
Total contractual obligations	$ 6,339	$ 1,123	$ 1,381	$ 743	$ 3,092	$ —

(a) Includes $258 million due after 2017 to the BGE financing trusts.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2013 and do not reflect anticipated future refinancing, early redemptions or debt issuances.
(c) Represents commitments to purchase natural gas and related transportation, storage capacity and services, procure electric supply, and curtailment services. See Note 22 of the Combined Notes to Consolidated Financial Statements for additional information.
(d) Under its operating agreement with PJM, BGE is committed to the construction of transmission facilities to maintain system reliability. These amounts represent BGE's expected portion of the costs to pay for the completion of the required construction projects. See Note 3 of Combined Notes to Consolidated Financial Statements for additional information.

See Note 22 of the Combined Notes to Consolidated Financial Statements for discussion of the Registrants' other commitments potentially triggered by future events.

For additional information regarding:

- commercial paper, see Note 13 of the Combined Notes to Consolidated Financial Statements.
- long-term debt, see Note 13 of the Combined Notes to Consolidated Financial Statements.
- liabilities related to uncertain tax positions, see Note 14 of the Combined Notes to Consolidated Financial Statements.
- capital lease obligations, see Note 13 of the Combined Notes to Consolidated Financial Statements.
- operating leases, energy commitments, fuel purchase agreements, construction commitments and rate relief commitments, see Note 22 of the Combined Notes to Consolidated Financial Statements.
- the nuclear decommissioning and SNF obligations, see Notes 15 and 22 of the Combined Notes to Consolidated Financial Statements.
- regulatory commitments, see Note 3 of the Combined Notes to Consolidated Financial Statements.
- variable interest entities, see Note 1 of the Combined Notes to Consolidated Financial Statements.
- nuclear insurance, see Note 22 of the Combined Notes to Consolidated Financial Statements.
- new accounting pronouncements, see Note 1 of the Combined Notes to Consolidated Financial Statements.

ITEM 7A. 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.

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 non-derivative contracts as well as 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 will occur during 2014 through 2016.

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 December 31, 2013, the percentage of expected generation hedged for the major reportable segments was 92%-95%, 62%-65% and 30%-33% for 2014, 2015 and 2016, 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 December 31, 2013, market conditions and hedged position would be a decrease in pre-tax net income of approximately $30 million, $520 million and $820 million, respectively, for 2014, 2015 and 2016. 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 8,762 GWh, 12,958 GWh, and 5,742 GWh for the years ended December 31, 2013, 2012 and 2011 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 year ended December 31, 2013, resulted in pre-tax losses of $8 million due to net mark-to-market losses of $39 million and realized gains of $31 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 $1.0 million of exposure during the year. Generation has not segregated proprietary trading activity within the following discussion because of the relative size of the proprietary trading portfolio in comparison to Generation's total gross margin from continuing operations for the year ended December 31, 2013 of $7,433 million.

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 2014 through 2018 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 22 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 would be entitled to receive full cost recovery in rates. The change in fair value each period was recorded by ComEd with an offset to a regulatory asset or liability. This financial swap contract between Generation and ComEd expired on May 31, 2013. All realized impacts have been included in Generation's and ComEd's results of operations.

ComEd entered into 20-year contracts for renewable energy and RECs beginning in June 2012. ComEd is permitted to recover its renewable energy and REC costs from retail customers with no mark-up. The annual commitments represent the maximum settlements with suppliers for renewable energy and RECs under the existing contract terms. Pursuant to the ICC's Order on December 19, 2012, ComEd's commitments under the existing long-term contracts were reduced for the June 2013 through May 2014 procurement period. The ICC's December 18, 2013 order approved the reduction of ComEd's commitments under the long-term contracts for the June 2014 through May 2015 procurement period, however the amount of the reduction will not be finalized and approved by the ICC until March 2014. See Notes 3 and 12 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 3 of the Combined Notes to the Consolidated Financial Statements. PECO's full requirements contracts and block contracts, which are considered derivatives, qualify for the normal purchases and normal sales scope exception under current derivative authoritative guidance and as a result, are accounted for on an accrual basis of accounting. 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 12 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 and as a result, are accounted for on an accrual basis of accounting. 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 12 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).

The following table provides detail on changes in Exelon's, Generation's, and ComEd's mark-to-market net asset or liability balance sheet position from January 1, 2012, to December 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 and does not segregate proprietary trading activity. See Note 12 of the Combined Notes to the Consolidated Financial Statements for more information on the balance sheet classification of the mark-to-market energy contract net assets (liabilities) recorded as of December 31, 2013, and December 31, 2012.

	Generation	ComEd	Intercompany Eliminations (b)	Exelon
Total mark-to-market energy contract net assets (liabilities) at January 1, 2012 (a)	$ 1,648	$ (800)	$ -	$ 848
Contracts acquired at merger date (c)	140	-	-	140
Total change in fair value during 2012 of contracts recorded in result of operations	(159)	-	7	(152)
Reclassification to realized at settlement of contracts recorded in results of operations	775	-	-	775
Ineffective portion recognized in income (d)	(5)	-	-	(5)
Reclassification to realized at settlement from accumulated OCI (e)	(1,368)	-	621	(747)
Effective portion of changes in fair value—recorded in OCI (f)	719	-	(146)	573
Changes in fair value—energy derivatives (g)	-	507	(482)	25
Changes in allocated collateral	(89)	-	-	(89)

Changes in net option premium paid/(received)	114	-	-	114
Option premium amortization (h)	(160)	-	-	(160)
Intercompany elimination of existing derivative contracts with Constellation	(103)	-	-	(103)
Other balance sheet reclassifications	(7)	-	-	(7)
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	444	-	(6)	438
Reclassification to realized at settlement of contracts recorded in results of operations	21	-	13	34
Reclassification to realized at settlement from accumulated OCI (e)	(683)	-	219	(464)
Changes in fair value—energy derivatives (g)	-	100	(226)	(126)
Changes in allocated collateral	(175)	-	-	(175)
Changes in net option premium paid/(received)	36	-	-	36
Option premium amortization (h)	(104)	-	-	(104)
Other balance sheet reclassifications	4	-	-	4
Total mark-to-market energy contract net assets (liabilities) at December 31, 2013 (a) (i)	$ 1,048	$ (193)	$ -	$ 855

(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.
(c) For Generation, includes $660 million of collateral paid to counterparties, offset by $520 million of unrealized losses on commodity derivative positions.
(d) For Generation, reflects $5 million of changes in cash flow hedge ineffectiveness.
(e) For Generation, includes $219 million and $621 million of losses from reclassifications from accumulated OCI to recognize gains in net income related to settlements of the five-year financial swap contract with ComEd for the years ended December 31, 2013 and 2012, respectively.
(f) For Generation, includes $146 million of gains related to the changes in fair value of the five-year financial swap with ComEd for the year ended 2012. Effective prior to the merger with Constellation, the five-year financial swap between Generation and ComEd was de-designated as a cash flow hedge. As a result, all changes in fair value for the year ended December 31, 2013 were recorded to operating revenues and eliminated in consolidation.
(g) For ComEd, the changes in fair value are recorded as a change in regulatory assets or liabilities. As of December 31, 2013 and 2012, ComEd recorded a regulatory liability of $193 million and $293 million, respectively, related to its mark-to-market derivative liabilities with Generation and unaffiliated suppliers. As of December 31, 2013 and 2012, this includes $11 million of decreases and $98 million of increases in fair value, respectively, and $215 million and $566 million, respectively, for reclassifications from regulatory assets to recognize cost in purchase power expense due to settlements of ComEd's five-year financial swap with Generation. As of December 31, 2013 and 2012 ComEd also recorded $126 million and $34 million, respectively, of increases in fair value, and $7 million and $5 million, respectively, of realized losses due to settlements associated with floating-to-fixed energy swap contracts with unaffiliated suppliers.
(h) Includes $104 million and $160 million of amounts reclassified to realized at settlement of contracts recorded to results of operations related to option premiums due to the settlement of the underlying transactions for the years ended December 31, 2013 and 2012, respectively.
(i) Includes the ending balance related to interest rate derivative contracts and foreign exchange currency swaps to manage the exposure related to the interest rate component of commodity positions and international purchases of commodities in currencies other than U.S. Dollars.

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 11 – Fair Value of Financial Assets and Liabilities of the Combined Notes to

Consolidated Financial Statements for additional information regarding fair value measurements and the fair value hierarchy.

Exelon

	Maturities Within						
	2014	2015	2016	2017	2018	2019 and Beyond	Total Fair Value
Normal Operations, Commodity derivative contracts (a)(b):							
Actively quoted prices (Level 1)	$ (30)	$ (26)	$ 17	$ (4)	$ (2)	$ -	$ (45)
Prices provided by external sources (Level 2)	444	143	39	-	-	1	627
Prices based on model or other valuation methods (Level 3) (c)	155	151	71	25	(22)	(108)	272
Total	$ 569	$ 268	$ 127	$ 21	$ (24)	$ (107)	$ 854

(a) Mark-to-market gains and losses on other economic hedge and trading derivative contracts that are recorded in 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 $144 million at December 31, 2013.
(c) Includes ComEd's net assets (liabilities) associated with the floating-to-fixed energy swap contracts with unaffiliated suppliers.

Generation

	Maturities Within						
	2014	2015	2016	2017	2018	2019 and Beyond	Total Fair Value
Normal Operations, Commodity derivative contracts (a)(b) :							
Actively quoted prices (Level 1)	$ (30)	$ (26)	$ 17	$ (4)	$ (2)	$ —	$ (45)
Prices provided by external sources (Level 2)	444	143	39	—	—	1	627
Prices based on model or other valuation methods (Level 3)	172	170	89	43	(4)	(5)	465
Total	$ 586	$ 287	$ 145	$ 39	$ (6)	$ (4)	$ 1,047

(a) Mark-to-market gains and losses on other 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 $144 million at December 31, 2013.

ComEd

	Maturities Within						
	2014	2015	2016	2017	2018	2019 and Beyond	Fair Value
Prices based on model or other valuation methods (Level 3) (a)	$ (17)	$ (19)	$ (18)	$ (18)	$ (18)	$ (103)	$ (193)

(a) Represents ComEd's net liabilities associated with 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 12 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 December 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 $38 million, $38 million and $27 million, respectively. See Note 25 of the Combined Notes to Consolidated Financial Statements for further information.

Rating as of December 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	$ 1,621	$ 172	$ 1,449	1	$ 491
Non-investment grade	27	9	18	—	—
No external ratings					
Internally rated - investment grade	416	1	415	1	226
Internally rated - non-investment grade	30	2	28	—	—
Total	$ 2,094	$ 184	$ 1,910	2	$ 717

Rating as of December 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	$ 1,146	$ 340	$ 135	$ 1,621
Non-investment grade	23	4	—	27
No external ratings				
Internally rated - investment grade	272	138	6	416
Internally rated - non-investment grade	30	—	—	30
Total	$ 1,471	$ 482	$ 141	$ 2,094

Net Credit Exposure by Type of Counterparty	As of December 31, 2013
Financial Institutions	$ 256
Investor-owned utilities, marketers and power producers	684
Energy cooperatives and municipalities	907

Other	63
Total	$ 1,910

(a) As of December 31, 2013, credit collateral held from counterparties where Generation had credit exposure included $155 million of cash and $29 million of letters of credit.

ComEd

Credit risk for ComEd is managed by credit and collection policies, which are consistent with state regulatory requirements. ComEd is currently obligated to provide service to all electric customers within its franchised territory. ComEd records a provision for uncollectible accounts, based upon historical experience, to provide for the potential loss from nonpayment by these customers. See Note 1 of the Combined Notes to Consolidated Financial Statements for the allowance for uncollectible accounts policy. ComEd is permitted to recover its costs of procuring energy through the Illinois Settlement Legislation as well as the ICC-approved procurement tariffs. ComEd will monitor nonpayment from customers and will make any necessary adjustments to the provision for uncollectible accounts. The Illinois Settlement Legislation prohibits utilities, including ComEd, from terminating electric service to a residential electric space heat customer due to nonpayment between December 1 of any year through March 1 of the following year. ComEd's ability to disconnect non space-heating residential customers is also impacted by certain weather restrictions, at any time of year, under the Illinois Public Utilities Act. ComEd will monitor the impact of its disconnection practices and will make any necessary adjustments to the provision for uncollectible accounts. ComEd did not have any customers representing over 10% of its revenues as of December 31, 2013. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information regarding ComEd's recently approved tariffs to adjust rates annually through a rider mechanism to reflect increases or decreases in annual uncollectible accounts expense.

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. ComEd's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. As of December 31, 2013, ComEd's credit exposure to energy suppliers was immaterial.

PECO

Credit risk for PECO is managed by credit and collection policies, which are consistent with state regulatory requirements. PECO is currently obligated to provide service to all retail electric customers within its franchised territory. PECO records a provision for uncollectible accounts to provide for the potential loss from nonpayment by these customers. See Note 1 of the Combined Notes to Consolidated Financial Statements for the allowance for uncollectible accounts policy. In accordance with PAPUC regulations, after November 30 and before April 1, an electric distribution utility or natural gas distribution utility shall not terminate service to customers with household incomes at or below 250% of the Federal poverty level. PECO's provision for uncollectible accounts will continue to be affected by changes in prices as well as changes in PAPUC regulations. PECO did not have any customers representing over 10% of its revenues as of December 31, 2013.

PECO's supplier master agreements that govern the terms of its DSP Program 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 December 31, 2013, PECO had no net credit exposure with suppliers.

PECO does not obtain cash collateral from suppliers under its natural gas supply and asset management agreements. As of December 31, 2013, PECO had credit exposure of $9 million under its natural gas supply and asset management agreements with investment grade suppliers.

BGE

Credit risk for BGE is managed by credit and collection policies, which are consistent with state regulatory requirements. BGE is currently obligated to provide service to all electric customers within its franchised territory. BGE records a provision for uncollectible accounts to provide for the potential loss from nonpayment by these customers. BGE will monitor nonpayment from customers and will make any necessary adjustments to the provision for uncollectible accounts. See Note 1 of the Combined Notes to Consolidated Financial Statements for uncollectible accounts policy. MDPSC regulations prohibit BGE from terminating service to residential customers due to nonpayment from November 1 through March 31 if the forecasted temperature is 32 degrees or below for the subsequent 72 hour period. BGE is also prohibited by the Maryland Public Utilities Article and MDPSC regulations from terminating service to residential customers due to nonpayment if the forecasted temperature is 95 degrees or above for the subsequent 72 hour period. BGE did not have any customers representing over 10% of its revenues as of December 31, 2013.

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 December 31, 2013, BGE had no net credit exposure with 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 December 31, 2013, BGE had credit exposure of $14 million related to off-system sales which is mitigated by parental guarantees, letters of credit, or right to offset clauses within other contracts with those third-party suppliers.

Collateral (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 12 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 13 of the Combined Notes to Consolidated Financial Statements for additional information.

As of December 31, 2013, Generation had cash collateral of $72 million posted and cash collateral held of $207 million for counterparties with derivative positions, of which $144 million in net cash collateral deposits were offset against mark-to-market assets and liabilities. As of December 31, 2013, $10 million of cash collateral posted was not offset against net derivative positions because it was not associated with energy-related derivatives. As of December 31, 2012, Generation had cash collateral held of $499 million and cash collateral posted of $527 million for counterparties with derivative positions, of which $31 million in net cash collateral deposits were offset against mark-to-market assets and liabilities. As of December 31, 2012, $3 million of cash collateral received was not offset against net mark-to-market assets and liabilities because it was not associated with energy-related derivatives. See Note 22 of the Combined Notes to Consolidated Financial Statements for information regarding the letters of credit supporting the cash collateral.

ComEd

As of December 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 for both annual and long-term renewable energy contracts. See Notes 3 and 12 of the Combined Notes to Consolidated Financial Statements for further information.

PECO

As of December 31, 2013, PECO was not required to post collateral under its energy and natural gas procurement contracts. See Note 12 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 December 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 12 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 sheet, as of December 31, 2013, included a $698 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 $1,465 million, less unearned income of $767 million. The lease agreements provide the lessees with fixed purchase options at the end of the lease terms. If the lessees do not exercise the fixed purchase options, Exelon has the ability to require the lessees to return the leasehold interests or to arrange for a third-party to bid on a service contract for a period following the lease term. If Exelon chooses the service contract option, the leasehold interests will be returned to Exelon at the end of the term of the service contract. In any event, Exelon will be subject to residual value risk if the lessees do not exercise the fixed purchase options. This risk is partially mitigated by the fair value of the scheduled payments under the service contract. However, such payments are not guaranteed. Further, the term of the service contract is less than the expected remaining useful life of the plants and, therefore, Exelon's exposure to residual value risk will not be mitigated by payments under the service contract in this remaining period. Lessee performance under the lease agreements is supported by collateral and credit enhancement measures. Management regularly evaluates the creditworthiness of Exelon's counterparties to these long-term leases. Exelon monitors the continuing credit quality of the credit enhancement party.

Pursuant to the applicable accounting guidance, Exelon is required to review the estimated residual values of its direct financing lease investments at least annually and, if the review indicates a fair value below the carrying value and the decline is determined to be other than temporary, must record an impairment charge in the period the estimate changed. Based on the review performed in the second quarter of 2013, the estimated residual value of one of Exelon's direct financing leases experienced an other than temporary decline resulting in a $14 million pre-tax impairment charge in the second quarter of 2013. See Note 8 of the Combined Notes to Consolidated Financial Statements for further information. Through December 31, 2013, no events have occurred that would require Exelon to review the estimated residual values of its direct financing lease investments subsequent to the review performed in the second quarter of 2013.

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 December 31, 2013, Exelon had $1,425 million of notional amounts of fixed-to-floating hedges outstanding and $190 million of notional amounts of floating-to-fixed hedges outstanding. Assuming the fair value and cash flow interest rate hedges are 100% effective, a hypothetical 50 bps increase in the interest rates associated with unhedged variable-rate debt (excluding Commercial Paper) and fixed-to-floating swaps would result in an approximate $5 million decrease in Exelon Consolidated pre-tax income for the year ended December 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 December 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 $482 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 7. 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 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Generation

General

Generation operates in six segments: Mid-Atlantic, Midwest, New England, New York, ERCOT, and Other Regions in Generation. The operation of all six segments consists of owned contracted and investments in electric generating facilities, and 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. These segments are discussed in further detail in "ITEM 1. BUSINESS - Generation" of this Form 10-K.

Executive Overview

A discussion of items pertinent to Generation's executive overview is set forth under "ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - Exelon—Executive Overview" of this Form 10-K.

Results of Operations

Year Ended December 31, 2013 Compared To Year Ended December 31, 2012 and Year Ended December 31, 2012 Compared to Year Ended December 31, 2011

A discussion of Generation's results of operations for 2013 compared to 2012 and 2012 compared to 2011 is set forth under "Results of Operations—Generation" in "EXELON CORPORATION—Results of Operations" of this Form 10-K.

Liquidity and Capital Resources

Generation's business is capital intensive and requires considerable capital resources. Generation's capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt, commercial paper, participation in the intercompany money pool or capital contributions from Exelon. Generation's access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. If these conditions deteriorate to where Generation no longer has access to the capital markets at reasonable terms, Generation has access to credit facilities in the aggregate of $5.6 billion that Generation currently utilizes to support its commercial paper program and to issue letters of credit.

See the "EXELON CORPORATION—Liquidity and Capital Resources" and Note 13 of the Combined Notes to Consolidated Financial Statements of this Form 10-K for further discussion.

Capital resources are used primarily to fund Generation's capital requirements, including construction, retirement of debt, the payment of distributions to Exelon, contributions to Exelon's pension plans and investments in new and existing ventures. Future acquisitions could require external financing or borrowings or capital contributions from Exelon.

Cash Flows from Operating Activities

A discussion of items pertinent to Generation's cash flows from operating activities is set forth under "Cash Flows from Operating Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Cash Flows from Investing Activities

A discussion of items pertinent to Generation's cash flows from investing activities is set forth under "Cash Flows from Investing Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Cash Flows from Financing Activities

A discussion of items pertinent to Generation's cash flows from financing activities is set forth under "Cash Flows from Financing Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Credit Matters

A discussion of credit matters pertinent to Generation is set forth under "Credit Matters" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Contractual Obligations and Off-Balance Sheet Arrangements

A discussion of Generation's contractual obligations, commercial commitments and off-balance sheet arrangements is set forth under "Contractual Obligations and Off-Balance Sheet Arrangements" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Critical Accounting Policies and Estimates

See Exelon, Generation, ComEd and PECO—Critical Accounting Policies and Estimates above for a discussion of Generation's critical accounting policies and estimates.

New Accounting Pronouncements

See Note 1 of the Combined Notes to Consolidated Financial Statements for information regarding new accounting pronouncements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Generation

Generation is exposed to market risks associated with commodity price, credit, interest rates and equity price. These risks are described above under "Quantitative and Qualitative Disclosures about Market Risk—Exelon."

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

ComEd

General

ComEd operates in a single business segment and its operations consist of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services to retail customers in northern Illinois, including the City of Chicago. This segment is discussed in further detail in "ITEM 1. BUSINESS - ComEd" of this Form 10-K.

Executive Overview

A discussion of items pertinent to ComEd's executive overview is set forth under "EXELON CORPORATION—Executive Overview" of this Form 10-K.

Results of Operations

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012 and Year Ended December 31, 2012 Compared to Year Ended December 31, 2011

A discussion of ComEd's results of operations for 2013 compared to 2012 and for 2012 compared to 2011 is set forth under "Results of Operations—ComEd" in "EXELON CORPORATION—Results of Operations" of this Form 10-K.

Liquidity and Capital Resources

ComEd's business is capital intensive and requires considerable capital resources. ComEd's capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt, commercial paper or credit facility borrowings. ComEd's access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. At December 31, 2013, ComEd had access to a revolving credit facility with aggregate bank commitments of $1 billion. See the "Credit Matters" section of "Liquidity and Capital Resources" for additional discussion.

See the "EXELON CORPORATION—Liquidity and Capital Resources" and Note 13 of the Combined Notes to Consolidated Financial Statements of this Form 10-K for further discussion.

Capital resources are used primarily to fund ComEd's capital requirements, including construction, retirement of debt, and contributions to Exelon's pension plans. Additionally, ComEd operates in rate-regulated environments in which the amount of new investment recovery may be limited and where such recovery takes place over an extended period of time.

Cash Flows from Operating Activities

A discussion of items pertinent to ComEd's cash flows from operating activities is set forth under "Cash Flows from Operating Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Cash Flows from Investing Activities

A discussion of items pertinent to ComEd's cash flows from investing activities is set forth under "Cash Flows from Investing Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Cash Flows from Financing Activities

A discussion of items pertinent to ComEd's cash flows from financing activities is set forth under "Cash Flows from Financing Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Credit Matters

A discussion of credit matters pertinent to ComEd is set forth under “Credit Matters” in “EXELON CORPORATION—Liquidity and Capital Resources” of this Form 10-K.

Contractual Obligations and Off-Balance Sheet Arrangements

A discussion of ComEd’s contractual obligations, commercial commitments and off-balance sheet arrangements is set forth under “Contractual Obligations and Off-Balance Sheet Arrangements” in “EXELON CORPORATION—Liquidity and Capital Resources” of this Form 10-K.

Critical Accounting Policies and Estimates

See Exelon, Generation, ComEd and PECO—Critical Accounting Policies and Estimates above for a discussion of ComEd’s critical accounting policies and estimates.

New Accounting Pronouncements

See Note 1 of the Combined Notes to Consolidated Financial Statements for information regarding new accounting pronouncements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

ComEd

ComEd is exposed to market risks associated with commodity price, credit and interest rates. These risks are described above under “Quantitative and Qualitative Disclosures about Market Risk— Exelon.”

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

PECO

General

PECO operates in a single business segment and its operations consist 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 service in Pennsylvania in the counties surrounding the City of Philadelphia. This segment is discussed in further detail in "ITEM 1. BUSINESS - PECO" of this Form 10-K.

Executive Overview

A discussion of items pertinent to PECO's executive overview is set forth under "EXELON CORPORATION—Executive Overview" of this Form 10-K.

Results of Operations

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012 and Year Ended December 31, 2012 Compared to Year Ended December 31, 2011

A discussion of PECO's results of operations for 2013 compared to 2012 and for 2012 compared to 2011 is set forth under "Results of Operations—PECO" in "EXELON CORPORATION—Results of Operations" of this Form 10-K.

Liquidity and Capital Resources

PECO's business is capital intensive and requires considerable capital resources. PECO's capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt, commercial paper or participation in the intercompany money pool. PECO's access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. If these conditions deteriorate to where PECO no longer has access to the capital markets at reasonable terms, PECO has access to a revolving credit facility. At December 31, 2013, PECO had access to a revolving credit facility with aggregate bank commitments of $600 million. See the "Credit Matters" section of "Liquidity and Capital Resources" for additional discussion.

Capital resources are used primarily to fund PECO's capital requirements, including construction, retirement of debt, the payment of dividends and contributions to Exelon's pension plans. Additionally, PECO operates in a rate-regulated environment in which the amount of new investment recovery may be limited and where such recovery takes place over an extended period of time.

Cash Flows from Operating Activities

A discussion of items pertinent to PECO's cash flows from operating activities is set forth under "Cash Flows from Operating Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Cash Flows from Investing Activities

A discussion of items pertinent to PECO's cash flows from investing activities is set forth under "Cash Flows from Investing Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Cash Flows from Financing Activities

A discussion of items pertinent to PECO's cash flows from financing activities is set forth under "Cash Flows from Financing Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Credit Matters

A discussion of credit matters pertinent to PECO is set forth under "Credit Matters" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Contractual Obligations and Off-Balance Sheet Arrangements

A discussion of PECO's contractual obligations, commercial commitments and off-balance sheet arrangements is set forth under "Contractual Obligations and Off-Balance Sheet Arrangements" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Critical Accounting Policies and Estimates

See Exelon, Generation, ComEd and PECO—Critical Accounting Policies and Estimates above for a discussion of PECO's critical accounting policies and estimates.

New Accounting Pronouncements

See Note 1 of the Combined Notes to Consolidated Financial Statements for information regarding new accounting pronouncements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

PECO

PECO is exposed to market risks associated with credit and interest rates. These risks are described above under "Quantitative and Qualitative Disclosures about Market Risk—Exelon."

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

BGE

General

BGE operates in a single business segment and its operations consist 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 service in central Maryland, including the City of Baltimore. This segment is discussed in further detail in "ITEM 1. BUSINESS - BGE" of this Form 10-K.

Executive Overview

A discussion of items pertinent to BGE's executive overview is set forth under "EXELON CORPORATION—Executive Overview" of this Form 10-K.

Results of Operations

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012 and Year Ended December 31, 2012 Compared to Year Ended December 31, 2011

A discussion of BGE's results of operations for 2013 compared to 2012 and for 2012 compared to 2011 is set forth under "Results of Operations—BGE" in "EXELON CORPORATION—Results of Operations" of this Form 10-K.

Liquidity and Capital Resources

BGE's business is capital intensive and requires considerable capital resources. BGE's capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt or commercial paper. BGE's access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. If these conditions deteriorate to where BGE no longer has access to the capital markets at reasonable terms, BGE has access to a revolving credit facility. At December 31, 2013, BGE had access to a revolving credit facility with aggregate bank commitments of $600 million. See the "Credit Matters" section of "Liquidity and Capital Resources" for additional discussion.

Capital resources are used primarily to fund BGE's capital requirements, including construction, retirement of debt, the payment of dividends and contributions to Exelon's pension plans. Additionally, BGE operates in a rate-regulated environment in which the amount of new investment recovery may be limited and where such recovery takes place over an extended period of time.

Cash Flows from Operating Activities

A discussion of items pertinent to BGE's cash flows from operating activities is set forth under "Cash Flows from Operating Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Cash Flows from Investing Activities

A discussion of items pertinent to BGE's cash flows from investing activities is set forth under "Cash Flows from Investing Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Cash Flows from Financing Activities

A discussion of items pertinent to BGE's cash flows from financing activities is set forth under "Cash Flows from Financing Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Credit Matters

A discussion of credit matters pertinent to BGE is set forth under “Credit Matters” in “EXELON CORPORATION—Liquidity and Capital Resources” of this Form 10-K.

Contractual Obligations and Off-Balance Sheet Arrangements

A discussion of BGE’s contractual obligations, commercial commitments and off-balance sheet arrangements is set forth under “Contractual Obligations and Off-Balance Sheet Arrangements” in “EXELON CORPORATION—Liquidity and Capital Resources” of this Form 10-K.

Critical Accounting Policies and Estimates

See Exelon, Generation, ComEd, PECO and BGE—Critical Accounting Policies and Estimates above for a discussion of BGE’s critical accounting policies and estimates.

New Accounting Pronouncements

See Note 1 of the Combined Notes to Consolidated Financial Statements for information regarding new accounting pronouncements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

BGE

BGE is exposed to market risks associated with credit and interest rates. These risks are described above under “Quantitative and Qualitative Disclosures about Market Risk—Exelon.”

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Management's Report on Internal Control Over Financial Reporting

The management of Exelon Corporation (Exelon) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed 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.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Exelon's management conducted an assessment of the effectiveness of Exelon's internal control over financial reporting as of December 31, 2013. In making this assessment, management used the criteria in *Internal Control—Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, Exelon's management concluded that, as of December 31, 2013, Exelon's internal control over financial reporting was effective.

The effectiveness of the Exelon's internal control over financial reporting as of December 31, 2013, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 13, 2014

Management's Report on Internal Control Over Financial Reporting

The management of Exelon Generation Company, LLC (Generation) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed 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.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Generation's management conducted an assessment of the effectiveness of Generation's internal control over financial reporting as of December 31, 2013. In making this assessment, management used the criteria in *Internal Control—Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, Generation's management concluded that, as of December 31, 2013, Generation's internal control over financial reporting was effective.

The effectiveness of the Generation's internal control over financial reporting as of December 31, 2013, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 13, 2014

Management's Report on Internal Control Over Financial Reporting

The management of Commonwealth Edison Company (ComEd) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed 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.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

ComEd's management conducted an assessment of the effectiveness of ComEd's internal control over financial reporting as of December 31, 2013. In making this assessment, management used the criteria in *Internal Control—Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, ComEd's management concluded that, as of December 31, 2013, ComEd's internal control over financial reporting was effective.

The effectiveness of the ComEd's internal control over financial reporting as of December 31, 2013, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 13, 2014

Management's Report on Internal Control Over Financial Reporting

The management of PECO Energy Company (PECO) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed 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.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PECO's management conducted an assessment of the effectiveness of PECO's internal control over financial reporting as of December 31, 2013. In making this assessment, management used the criteria in *Internal Control—Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, PECO's management concluded that, as of December 31, 2013, PECO's internal control over financial reporting was effective.

The effectiveness of the PECO's internal control over financial reporting as of December 31, 2013, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 13, 2014

Management's Report on Internal Control Over Financial Reporting

The management of Baltimore Gas and Electric Company (BGE) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed 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.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

BGE's management conducted an assessment of the effectiveness of BGE's internal control over financial reporting as of December 31, 2013. In making this assessment, management used the criteria in *Internal Control—Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, BGE's management concluded that, as of December 31, 2013, BGE's internal control over financial reporting was effective.

The effectiveness of BGE's internal control over financial reporting as of December 31, 2013, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 13, 2014

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Exelon Corporation:

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of Exelon Corporation ("the Company") and its subsidiaries at December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedules listed in the index appearing under item 15(a)(2) present fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on criteria established in *Internal Control - Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedules, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express opinions on these financial statements, on the financial statement schedules, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed 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. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP
Chicago, Illinois
February 13, 2014

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Member of Exelon Generation Company, LLC:

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of Exelon Generation Company, LLC ("the Company") and its subsidiaries at December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on criteria established in *Internal Control - Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed 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. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP
Baltimore, Maryland
February 13, 2014

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Commonwealth Edison Company:

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of Commonwealth Edison Company ("the Company") and its subsidiaries at December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on criteria established in *Internal Control - Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed 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. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP
Chicago, Illinois
February 13, 2014

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of PECO Energy Company:

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of PECO Energy Company ("the Company") and its subsidiaries at December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on criteria established in *Internal Control - Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed 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. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP
Philadelphia, Pennsylvania
February 13, 2014

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Baltimore Gas and Electric Company:

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of Baltimore Gas and Electric Company ("the Company") and its subsidiaries at December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on criteria established in *Internal Control - Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our audits (which was an integrated audit in 2012). We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed 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. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP
Baltimore, Maryland
February 13, 2014

(In millions, except per share data)	For the Years Ended December 31, 2013	2012	2011
Operating revenues	$ 24,888	$ 23,489	$ 19,063
Operating expenses			
Purchased power and fuel	9,468	9,121	7,130
Purchased power and fuel from affiliates	1,256	1,036	137
Operating and maintenance	7,270	7,961	5,184
Depreciation and amortization	2,153	1,881	1,347
Taxes other than income	1,095	1,019	785
Total operating expenses	21,242	21,018	14,583
Equity in earnings (losses) of unconsolidated affiliates	10	(91)	(1)
Operating income	3,656	2,380	4,479
Other income and (deductions)			
Interest expense, net	(1,315)	(891)	(701)
Interest expense to affiliates, net	(41)	(37)	(25)
Other, net	473	346	203
Total other income and (deductions)	(883)	(582)	(523)
Income before income taxes	2,773	1,798	3,956
Income taxes	1,044	627	1,457
Net income	1,729	1,171	2,499
Net income attributable to non-controlling interests, preferred security dividends and preference stock dividends	10	11	4
Net income attributable to common shareholders	1,719	1,160	2,495
Comprehensive income (loss), net of income taxes			
Net income	1,729	1,171	2,499
Other comprehensive income (loss)			
Pension and non-pension postretirement benefit plans:			
Prior service cost (benefit) reclassified to periodic costs, net of taxes of $0, $1 and $(4), respectively	-	1	(5)
Actuarial loss reclassified to periodic cost, net of taxes of $133, $110 and $93, respectively	208	168	136
Transition obligation reclassified to periodic cost, net of taxes of $0, $2 and $2, respectively	-	2	4
Pension and non-pension postretirement benefit plan valuation adjustment, net of taxes of $430, $(237) and $(171), respectively	669	(371)	(250)
Unrealized gain (loss) on cash flow hedges, net of taxes of $(166), $(68) and $39, respectively	(248)	(120)	88
Unrealized gain (loss) on marketable securities, net of taxes of $0, $(1) and $0, respectively	2	2	-
Unrealized gain (loss) on equity investments, net of taxes of $71, $1 and $0, respectively	106	1	-
Unrealized gain (loss) on foreign currency translation, net of taxes of $0, $0 and $0, respectively	(10)	-	-
Other comprehensive income (loss)	727	(317)	(27)
Comprehensive income	$ 2,456	$ 854	$ 2,472
Average shares of common stock outstanding:			
Basic	856	816	663
Diluted	860	819	665
Earnings per average common share:			
Basic	$ 2.01	$ 1.42	$ 3.76
Diluted	$ 2.00	$ 1.42	$ 3.75
Dividends per common share	$ 1.46	$ 2.10	$ 2.10

(In millions)	2013	2012	2011
	For the Years Ended December 31,		
Cash flows from operating activities			
Net income	$ 1,729	$ 1,171	$ 2,499
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	3,779	4,079	2,316
Loss on sale of three Maryland generating stations	—	272	—
Deferred income taxes and amortization of investment tax credits	119	615	1,457
Net fair value changes related to derivatives	(445)	(604)	291
Net realized and unrealized (gains) losses on nuclear decommissioning trust fund investments	(170)	(157)	14
Other non-cash operating activities	876	1,383	770
Changes in assets and liabilities:			
Accounts receivable	(97)	243	57
Inventories	(100)	26	(58)
Accounts payable, accrued expenses and other current liabilities	(90)	(632)	(254)
Option premiums paid, net	(36)	(114)	(3)
Counterparty collateral received (posted), net	215	135	(344)
Income taxes	883	544	492
Pension and non-pension postretirement benefit contributions	(422)	(462)	(2,360)
Other assets and liabilities	102	(368)	(24)
Net cash flows provided by operating activities	6,343	6,131	4,853
Cash flows from investing activities			
Capital expenditures	(5,395)	(5,789)	(4,042)
Proceeds from nuclear decommissioning trust fund sales	4,217	7,265	6,139
Investment in nuclear decommissioning trust funds	(4,450)	(7,483)	(6,332)
Cash and restricted cash acquired from Constellation	—	964	—
Acquisitions of long lived assets	—	(21)	(387)
Proceeds from sale of long-lived assets	32	371	—
Proceeds from sales of investments	22	28	6
Purchases of investments	(4)	(13)	(4)
Change in restricted cash	(43)	(34)	(3)
Distribution from CENG	115	—	—
Other investing activities	112	136	20
Net cash flows used in investing activities	(5,394)	(4,576)	(4,603)
Cash flows from financing activities			
Payment of accounts receivable agreement	(210)	(15)	—
Changes in short-term debt	332	(197)	161
Issuance of long-term debt	2,055	2,027	1,199
Retirement of long-term debt	(1,589)	(1,145)	(789)
Redemption of preferred securities	(93)	—	—
Dividends paid on common stock	(1,249)	(1,716)	(1,393)
Proceeds from employee stock plans	47	72	38
Other financing activities	(119)	(111)	(62)
Net cash flows used in financing activities	(826)	(1,085)	(846)
Increase (decrease) in cash and cash equivalents	123	470	(596)
Cash and cash equivalents at beginning of period	1,486	1,016	1,612

Cash and cash equivalents at end of period	$ 1,609	$ 1,486	$ 1,016

(In millions)	December 31, 2013	December 31, 2012
ASSETS		
Current assets		
Cash and cash equivalents	$ 1,547	$ 1,411
Cash and cash equivalents of variable interest entities	62	75
Restricted cash and investments	87	86
Restricted cash and investments of variable interest entities	80	47
Accounts receivable, net		
Customer ($0 and $289 gross accounts receivables pledged as collateral as of December 31, 2013 and December 31, 2012, respectively)	2,721	2,795
Other	1,175	1,141
Accounts receivable, net, of variable interest entities	260	292
Mark-to-market derivative assets	727	938
Unamortized energy contract assets	374	886
Inventories, net		
Fossil fuel	276	246
Materials and supplies	829	768
Deferred income taxes	573	131
Regulatory assets	760	764
Other	666	560
Total current assets	10,137	10,140
Property, plant and equipment, net	47,330	45,186
Deferred debits and other assets		
Regulatory assets	5,910	6,497
Nuclear decommissioning trust funds	8,071	7,248
Investments	1,165	1,184
Investments in affiliates	22	22
Investment in CENG	1,925	1,849
Goodwill	2,625	2,625
Mark-to-market derivative assets	607	937
Unamortized energy contract assets	710	1,073
Pledged assets for Zion Station decommissioning	458	614
Deferred income taxes	—	58
Other	964	1,128
Total deferred debits and other assets	22,457	23,235
Total assets	$ 79,924	$ 78,561

(In millions)	December 31, 2013	December 31, 2012
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$ 341	$ —
Short-term notes payable — accounts receivable agreement	—	210
Long-term debt due within one year	1,424	975
Long-term debt due within one year of variable interest entities	85	72
Accounts payable	2,314	2,378
Accounts payable of variable interest entities	170	202
Payables to affiliates	116	112
Mark-to-market derivative liabilities	159	352
Unamortized energy contract liabilities	261	455
Accrued expenses	1,633	1,796
Deferred income taxes	40	58
Regulatory liabilities	327	368
Other	858	813
Total current liabilities	7,728	7,791
Long-term debt	17,325	17,190
Long-term debt to financing trusts	648	648
Long-term debt of variable interest entities	298	508
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	12,905	11,551
Asset retirement obligations	5,194	5,074
Pension obligations	1,876	3,428
Non-pension postretirement benefit obligations	2,190	2,662
Spent nuclear fuel obligation	1,021	1,020
Regulatory liabilities	4,388	3,981
Mark-to-market derivative liabilities	300	281
Unamortized energy contract liabilities	266	528
Payable for Zion Station decommissioning	305	432
Other	2,540	1,650
Total deferred credits and other liabilities	30,985	30,607
Total liabilities	56,984	56,744
Commitments and contingencies		
Preferred securities of subsidiary	—	87
Shareholders' equity		
Common stock (No par value, 2,000 shares authorized, 857 and 855 shares outstanding at December 31, 2013 and 2012, respectively)	16,741	16,632
Treasury stock, at cost (35 shares held at December 31, 2013 and 2012, respectively)	(2,327)	(2,327)
Retained earnings	10,358	9,893
Accumulated other comprehensive loss, net	(2,040)	(2,767)
Total shareholders' equity	22,732	21,431
BGE preference stock not subject to mandatory redemption	193	193
Non-controlling interest	15	106
Total equity	22,940	21,730

Total liabilities and shareholders' equity	$ 79,924	$ 78,561

(In millions, shares in thousands)	Issued Shares	Common Stock	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Loss	Non-controlling Interest	Preferred and Preference Stock	Total Shareholders' Equity
Balance, December 31, 2010	696,589	$ 9,006	$ (2,327)	$ 9,304	$ (2,423)	$ 3	$ —	$ 13,563
Net income	—	—	—	2,495	—	—	4	2,499
Long-term incentive plan activity	861	76	—	—	—	—	—	76
Employee stock purchase plan issuances	662	25	—	—	—	—	—	25
Common stock dividends	—	—	—	(1,744)	—	—	—	(1,744)
Preferred and preference stock dividends	—	—	—	—	—	—	(4)	(4)
Other comprehensive income, net of income taxes of $(41)	—	—	—	—	(27)	—	—	(27)
Balance, December 31, 2011	698,112	$ 9,107	$ (2,327)	$ 10,055	$ (2,450)	$ 3	$ —	$ 14,388
Net income (loss)	—	—	—	1,160	—	(3)	14	1,171
Long-term incentive plan activity	2,432	126	—	—	—	—	—	126
Employee stock purchase plan								—
issuances	857	26	—	—	—	—	—	26
Common stock dividends	—	—	—	(1,322)	—	—	—	(1,322)
Common stock issuance Constellation merger	188,124	7,365	—	—	—	—	—	7,365
Non-controlling interest acquired	—	8	—	—	—	106	—	114
BGE preference stock acquired	—	—	—	—	—	—	193	193
Preferred and preference stock dividends	—	—	—	—	—	—	(14)	(14)
Other comprehensive loss, net of income taxes of $(192)	—	—	—	—	(317)	—	—	(317)
Balance, December 31, 2012	889,525	$ 16,632	$ (2,327)	$ 9,893	$ (2,767)	$ 106	$ 193	$ 21,730
Net income (loss)	—	—	—	1,719	—	(10)	20	1,729
Long-term incentive plan activity	1,445	81	—	—	—	—	—	81
Employee stock purchase plan issuances	1,064	28	—	—	—	—	—	28
Common stock dividends	—	—	—	(1,254)	—	—	—	(1,254)
Consolidated VIE dividend to non-controlling interest	—	—	—	—	—	(63)	—	(63)
Deconsolidation of VIE	—	—	—	—	—	(18)	—	(18)
Redemption of preferred securities	—	—	—	—	—	—	(6)	(6)
Preferred and preference stock stock dividends	—	—	—	—	—	—	(14)	(14)
Other comprehensive income, net of income taxes of $(468)	—	—	—	—	727	—	—	727
Balance, December 31, 2013	892,034	$ 16,741	$ (2,327)	$ 10,358	$ (2,040)	$ 15	$ 193	$ 22,940

(In millions)	For the Years Ended December 31, 2013	2012	2011
Operating revenues			
Operating revenues	$ 14,207	$ 12,735	$ 9,286
Operating revenues from affiliates	1,423	1,702	1,161
Total operating revenues	15,630	14,437	10,447
Operating expenses			
Purchased power and fuel	6,927	6,017	3,451
Purchased power and fuel from affiliates	1,270	1,044	138
Operating and maintenance	3,960	4,398	2,827
Operating and maintenance from affiliates	574	630	321
Depreciation and amortization	856	768	570
Taxes other than income	389	369	264
Total operating expenses	13,976	13,226	7,571
Equity in earnings (losses) of unconsolidated affiliates	10	(91)	(1)
Operating income	1,664	1,120	2,875
Other income and (deductions)			
Interest expense	(298)	(226)	(170)
Interest expense to affiliates, net	(59)	(75)	—
Other, net	368	239	122
Total other income and (deductions)	11	(62)	(48)
Income before income taxes	1,675	1,058	2,827
Income taxes	615	500	1,056
Net income	1,060	558	1,771
Net loss attributable to non-controlling interests	(10)	(4)	—
Net income attributable to membership interest	1,070	562	1,771
Comprehensive income (loss), net of income taxes			
Net income	1,060	558	1,771
Other comprehensive income (loss)			
Unrealized loss on cash flow hedges, net of income taxes of $(262), $(262) and $(64), respectively	(398)	(403)	(98)
Unrealized income on equity investments, net of income taxes of $72, $(1) and $0, respectively	107	1	—
Unrealized loss on foreign currency translation, net of income taxes of $0, $0 and $0, respectively	(10)	—	—
Unrealized gain on marketable securities, net of income taxes of $0, $0 and $0, respectively	2	—	—
Other comprehensive loss	(299)	(402)	(98)
Comprehensive income	$ 761	$ 156	$ 1,673

(In millions)	For the Years Ended December 31, 2013	2012	2011
Cash flows from operating activities			
Net income	$ 1,060	$ 558	$ 1,771
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization, depletion and accretion, including nuclear fuel and energy contract amortization	2,559	2,966	1,539
Loss on sale of three Maryland generating stations	—	272	—
Deferred income taxes and amortization of investment tax credits	315	408	551
Net fair value changes related to derivatives	(448)	(611)	291
Net realized and unrealized (gains) losses on nuclear decommissioning trust fund investments	(170)	(157)	14
Other non-cash operating activities	414	537	421
Changes in assets and liabilities:			
Accounts receivable	109	248	(122)
Receivables from and payables to affiliates, net	2	39	208
Inventories	(88)	31	(47)
Accounts payable, accrued expenses and other current liabilities	(109)	(499)	34
Option premiums paid, net	(36)	(114)	(3)
Counterparty collateral (posted) received, net	162	95	(410)
Income taxes	402	114	193
Pension and non-pension postretirement benefit contributions	(149)	(178)	(1,070)
Other assets and liabilities	(136)	(128)	(57)
Net cash flows provided by operating activities	3,887	3,581	3,313
Cash flows from investing activities			
Capital expenditures	(2,752)	(3,554)	(2,491)
Proceeds from nuclear decommissioning trust fund sales	4,217	7,265	6,139
Investment in nuclear decommissioning trust funds	(4,450)	(7,483)	(6,332)
Cash and restricted cash acquired from Constellation	—	708	—
Proceeds from sale of long-lived assets	32	371	—
Acquisitions of long lived assets	—	(21)	(387)
Change in restricted cash	(64)	4	—
Changes in Exelon intercompany money pool	(44)	—	—
Distribution from CENG	115	—	—
Other investing activities	30	81	(6)
Net cash flows used in investing activities	(2,916)	(2,629)	(3,077)
Cash flows from financing activities			
Change in short-term debt	13	(52)	—
Issuance of long-term debt	854	1,076	—
Retirement of long-term debt	(570)	(145)	(2)
Distribution to member	(625)	(1,626)	(172)
Contribution from member	26	48	30
Other financing activities	(82)	(78)	(52)
Net cash flows used in financing activities	(384)	(777)	(196)
Increase in cash and cash equivalents	587	175	40
Cash and cash equivalents at beginning of period	671	496	456

Cash and cash equivalents at end of period	$ 1,258	$ 671	$ 496