UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549

FORM 8-K/A

CURRENT REPORT

Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

March 9, 2012
Date of Report (Date of earliest event reported)

Commission File Number	Exact Name of Registrant as Specified in Its Charter; State of Incorporation; Address of Principal Executive Offices; and Telephone Number	IRS Employer Identification Number
1-16169	**EXELON CORPORATION** **(a Pennsylvania corporation)** **10 South Dearborn Street** **P.O. Box 805379** **Chicago, Illinois 60680-5379** **(312) 394-7398**	**23-2990190**
333-85496	**EXELON GENERATION COMPANY, LLC** **(a Pennsylvania limited liability company)** **300 Exelon Way** **Kennett Square, Pennsylvania 19348-2473** **(610) 765-5959**	**23-3064219**

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Introductory Note

As previously reported, on March 12, 2012, Exelon Corporation (Exelon) completed the previously announced merger contemplated by the Agreement and Plan of Merger, dated as of April 28, 2011 (the Merger Agreement), among Exelon, Constellation Energy Group, Inc. (Constellation), and Bolt Acquisition Corporation, formerly a Maryland corporation and wholly owned subsidiary of Exelon (Merger Sub). This Form 8-K/A amends the original Form 8-K filed on March 14, 2012, to include the financial statements of Constellation and Baltimore Gas and Electric Company (BGE) and pro forma financial information required by Items 9.01(a) and 9.01(b) of Form 8-K, respectively, and to include exhibits under 9.01(d) of Form 8-K.

Section 9 – Financial Statements and Exhibits

Item 9.01. Financial Statements and Exhibits.

(a) *Financial Statements of Businesses Acquired.*

The historical audited consolidated financial statements of Constellation and BGE as of December 31, 2011 and 2010, and for each of the three years in the period ended December 31, 2011 are attached as Exhibit 99.1 to this Current Report on Form 8-K/A and are incorporated herein by reference.

(b) *Pro Forma Financial Information.*

The unaudited pro forma condensed combined consolidated financial statements and explanatory notes relating to Exelon's acquisition of Constellation and Exelon's subsequent contribution to Exelon Generation Company, LLC (Generation) of certain subsidiaries, including the generation and customer supply businesses that were acquired from Constellation, are attached as Exhibit 99.2 to this Current Report on Form 8-K/A and are incorporated herein by reference.

(d) *Exhibits*.

Exhibit No.	Description
23.1	Consents of PricewaterhouseCoopers LLP.
99.1	Audited consolidated financial statements of Constellation and BGE as of December 31, 2011 and 2010, and for each of the three years in the period ended December 31, 2011.
99.2	Unaudited pro forma condensed combined consolidated financial statements and explanatory notes for the year in the period ended December 31, 2011 and the quarterly period ended March 31, 2012.

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This Current Report is being furnished separately by Exelon and Generation (Registrants). Information contained herein relating to any individual Registrant has been furnished by such Registrant on its own behalf. No Registrant makes any representation as to information relating to any other Registrant.

This Current Report includes certain forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995, that are subject to risks and uncertainties. The factors that could cause actual results to differ materially from the forward-looking statements made by the Registrants include those factors discussed herein, as well as the items discussed in (1) Exelon's 2011 Annual Report on Form 10-K in (a) ITEM 1A. Risk Factors, (b) ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and (c) ITEM 8. Financial Statements and Supplementary Data: Note 18; (2) Constellation's 2011 Annual Report on Form 10-K in (a) ITEM 1A. Risk Factors, (b) ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and (c) ITEM 8. Financial Statements and Supplementary Data: Note 12; (3) the Registrants' First Quarter 2012 Quarterly Report on Form 10-Q in (a) Part II, Other Information, ITEM 1A. Risk Factors and (b) Part I, Financial Information, ITEM 1. Financial Statements: Note 15; and (4) other factors discussed in filings with the SEC by the Registrants. Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this Current Report. Neither of the Registrants undertakes any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this Current Report.

SIGNATURES

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

EXELON CORPORATION

/s/ Jonathan W. Thayer

Jonathan W. Thayer
Executive Vice President and Chief Financial Officer
Exelon Corporation

EXELON GENERATION COMPANY, LLC

/s/ Andrew L. Good

Andrew L. Good
Senior Vice President and Chief Financial Officer
Exelon Generation Company, LLC

May 25, 2012

EXHIBIT INDEX

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Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (No. 333-164782) and Form S-8 (Nos. 333-37082, 333-49780, 333-127377, 333-61390 and 333-175162) of Exelon Corporation and on Form S-3 (No. 333-164782-07) of Exelon Generation Company, LLC of our report dated February 29, 2012, except for Note 18, as to which the date is May 25, 2012, relating to the financial statements of Constellation Energy Group Inc., which appears in this Current Report on Form 8-K/A of Exelon Corporation and Exelon Generation Company, LLC dated May 25, 2012.

/s/ PricewaterhouseCoopers LLP
Baltimore, Maryland

May 25, 2012

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (No. 333-164782) and Form S-8 (Nos. 333-37082, 333-49780, 333-127377, 333-61390 and 333-175162) of Exelon Corporation and on Form S-3 (No. 333-164782-07) of Exelon Generation Company, LLC of our report dated February 29, 2012 relating to the financial statements of Baltimore Gas and Electric Company, which appears in this Current Report on Form 8-K/A of Exelon Corporation and Exelon Generation Company, LLC dated May 25, 2012.

/s/ PricewaterhouseCoopers LLP
Baltimore, Maryland

May 25, 2012

Exhibit 99.1

CONSTELLATION ENERGY GROUP, INC
BALTIMORE GAS AND ELECTRIC COMPANY

AUDITED CONSOLIDATED FINANCIAL STATEMENTS

AS OF DECEMBER 31, 2011 AND 2010, AND FOR EACH OF THE THREE YEARS ENDED DECEMBER 31, 2011, 2010 AND 2009

REPORTS OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of

Constellation Energy Group, Inc.

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income (loss), of common shareholders' equity and comprehensive income (loss), and of cash flows present fairly, in all material respects, the financial position of Constellation Energy Group, Inc. and its subsidiaries (the "Company") at December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes 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. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 1 to the consolidated financial statements, in 2010 the Company changed its method of accounting for and presenting variable interest entities.

/s/ PricewaterhouseCoopers LLP
Baltimore, Maryland

February 29, 2012, except for Note 18, as to which the date is May 25, 2012.

To Board of Directors and Shareholder of

Baltimore Gas and Electric Company

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income and of cash flows present fairly, in all material respects, the financial position of Baltimore Gas and Electric Company and its subsidiaries (the Company) at December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes 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. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 1 to the consolidated financial statements, in 2010 the Company changed its method of accounting for and presenting variable interest entities.

/s/ PricewaterhouseCoopers LLP
Baltimore, Maryland

February 29, 2012

CONSOLIDATED STATEMENTS OF INCOME (LOSS)

Constellation Energy Group, Inc. and Subsidiaries

Year Ended December 31,	**2011**	2010	2009
	(In millions, except per share amounts)		
Revenues			
Nonregulated revenues	**$10,773.0**	$10,883.0	$12,024.3
Regulated electric revenues	**2,320.7**	2,752.1	2,820.7
Regulated gas revenues	**664.5**	704.9	753.8
Total revenues	**13,758.2**	14,340.0	15,598.8
Expenses			
Fuel and purchased energy expenses	**9,396.6**	10,001.7	11,013.1
Fuel and purchased energy expenses from affiliate	**888.4**	900.8	122.5
Operating expenses	**1,934.9**	1,691.1	2,228.0
Merger costs	**117.9**	—	145.8
Impairment losses and other costs	**891.0**	2,476.8	124.7
Workforce reduction costs	**—**	—	12.6
Depreciation, depletion, accretion, and amortization	**589.3**	519.5	651.4
Taxes other than income taxes	**308.0**	263.9	290.4
Total expenses	**14,126.1**	15,853.8	14,588.5
Equity Investment Earnings (Losses)	**19.8**	25.0	(6.1)
Gain on U.S. Department of Energy Settlement	**93.8**	—	—
Gain on Sale of Interest in CENG	**—**	—	7,445.6
Net Gain (Loss) on Divestitures	**57.3**	245.8	(468.8)
(Loss) Income from Operations	**(197.0)**	(1,243.0)	7,981.0
Other Expenses	**(75.3)**	(76.7)	(140.7)
Fixed Charges			
Interest expense	**276.6**	310.8	437.2
Interest capitalized and allowance for borrowed funds used during construction	**(11.2)**	(33.0)	(87.1)
Total fixed charges	**265.4**	277.8	350.1
(Loss) Income from Continuing Operations Before Income Taxes	**(537.7)**	(1,597.5)	7,490.2
Income Tax (Benefit) Expense	**(230.9)**	(665.7)	2,986.8
Net (Loss) Income	**(306.8)**	(931.8)	4,503.4
Net Income Attributable to Noncontrolling Interests and BGE Preference Stock Dividends	**33.5**	50.8	60.0
Net (Loss) Income Attributable to Common Stock	**$ (340.3)**	$ (982.6)	$ 4,443.4
Average Shares of Common Stock Outstanding—Basic	**200.1**	200.5	199.3
Average Shares of Common Stock Outstanding—Diluted	**200.1**	200.5	200.3
(Loss) Earnings Per Common Share—Basic	**$ (1.70)**	$ (4.90)	$ 22.29
(Loss) Earnings Per Common Share—Diluted	**$ (1.70)**	$ (4.90)	$ 22.19
Dividends Declared Per Common Share	**$ 0.96**	$ 0.96	$ 0.96

See Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS
Constellation Energy Group, Inc. and Subsidiaries

At December 31,	**2011**	2010
	(In millions)	
Assets		
Current Assets		
Cash and cash equivalents	**$ 964.5**	$ 2,028.5
Accounts receivable (net of allowance for uncollectibles of **$87.1** and $85.0, respectively)	**1,907.6**	2,059.2
Accounts receivable—consolidated variable interest entities (net of allowance for uncollectibles of **$115.5** and $87.9, respectively)	**247.9**	308.9
Income taxes receivable	**156.6**	152.7
Fuel stocks	**423.1**	361.1
Materials and supplies	**129.6**	104.3
Derivative assets	**357.9**	534.4
Unamortized energy contract assets (includes **$—**and $400.9, respectively, related to CENG)	**52.1**	544.7
Restricted cash	**2.3**	52.0
Restricted cash—consolidated variable interest entities	**44.8**	52.3
Regulatory assets (net)	**153.7**	78.7
Deferred income taxes	**132.0**	—
Other	**246.4**	175.8
Total current assets	**4,818.5**	6,452.6
Investments and Other Noncurrent Assets		
Investment in CENG	**2,150.4**	2,991.1
Other investments	**122.4**	189.9
Regulatory assets (net)	**341.9**	374.1
Goodwill	**282.2**	77.0
Derivative assets	**259.3**	258.9
Unamortized energy contract assets	**58.4**	109.8
Other	**380.5**	284.5
Other—consolidated variable interest entities	**95.7**	1.8
Total investments and other noncurrent assets	**3,690.8**	4,287.1
Property, Plant and Equipment		
Nonregulated property, plant and equipment	**7,780.4**	6,387.2
Regulated property, plant and equipment	**7,595.0**	7,201.7
Accumulated depreciation	**(4,472.1)**	(4,310.1)
Net property, plant and equipment	**10,903.3**	9,278.8
Total Assets	**$19,412.6**	$20,018.5

See Notes to Consolidated Financial Statements.

Certain prior-year amounts have been reclassified to conform with the current year's presentation.

CONSOLIDATED BALANCE SHEETS
Constellation Energy Group, Inc. and Subsidiaries

At December 31,	2011	2010
	(In millions)	
Liabilities and Equity		
Current Liabilities		
Short-term borrowings	**$ —**	$ 32.4
Short-term borrowings—consolidated variable interest entities	**39.5**	—
Current portion of long-term debt	**109.6**	245.6
Current portion of long-term debt—consolidated variable interest entities	**65.3**	59.7
Accounts payable	**924.8**	1,072.6
Accounts payable—consolidated variable interest entities	**177.2**	189.8
Customer deposits and collateral	**95.2**	87.2
Derivative liabilities	**779.5**	622.3
Unamortized energy contract liabilities	**118.1**	130.5
Deferred income taxes	**—**	56.5
Accrued taxes	**90.4**	71.0
Accrued expenses	**431.4**	358.1
Other	**456.8**	351.5
Total current liabilities	**3,287.8**	3,277.2
Deferred Credits and Other Noncurrent Liabilities		
Deferred income taxes	**2,305.1**	2,489.8
Asset retirement obligations	**37.6**	32.3
Derivative liabilities	**268.4**	353.0
Unamortized energy contract liabilities	**294.8**	411.1
Defined benefit obligations	**698.0**	574.7
Deferred investment tax credits	**23.6**	27.6
Other	**251.7**	296.0
Total deferred credits and other noncurrent liabilities	**3,879.2**	4,184.5
Long-term Debt, Net of Current Portion	**4,456.4**	4,054.2
Long-term Debt, Net of Current Portion—consolidated variable interest entities	**388.4**	394.6
Equity		
Common shareholders' equity	**7,093.9**	7,829.2
BGE preference stock not subject to mandatory redemption	**190.0**	190.0
Noncontrolling interests	**116.9**	88.8
Total equity	**7,400.8**	8,108.0
Commitments, Guarantees, and Contingencies (see Note 12)		
Total Liabilities and Equity	**$19,412.6**	$20,018.5

See Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS
Constellation Energy Group, Inc. and Subsidiaries

Year Ended December 31,	**2011**	2010	2009
		(In millions)	
Cash Flows From Operating Activities			
Net (loss) income	**$ (306.8)**	$ (931.8)	$ 4,503.4
Adjustments to reconcile to net cash provided by operating activities			
Depreciation, depletion, accretion, and amortization	**589.3**	519.5	651.4
Amortization of nuclear fuel	**—**	—	117.9
Amortization of energy contracts and derivatives designated as hedges	**438.0**	319.6	(138.4)
All other amortization	**39.4**	33.3	135.7
Deferred income taxes	**(193.7)**	(716.3)	1,847.0
Investment tax credit adjustments	**(4.3)**	(4.5)	(12.1)
Deferred fuel costs	**5.0**	67.4	68.9
Deferred storm costs	**(15.5)**	—	—
Defined benefit obligation expense	**93.6**	89.4	107.6
Defined benefit obligation payments	**(114.9)**	(324.0)	(372.5)
Merger costs	**62.5**	—	128.2
Workforce reduction costs	**—**	—	12.6
Impairment losses and other costs	**891.0**	2,476.8	124.7
Impairment losses on nuclear decommissioning trust assets	**—**	—	62.6
Gain on sale of 49.99% membership interest in CENG	**—**	—	(7,445.6)
(Gain) loss on divestitures	**(57.3)**	(245.8)	468.8
Gains on termination of contracts	**(26.9)**	(76.8)	—
Gain on U. S. Department of Energy settlement	**(58.4)**	—	—
Accrual of BGE residential customer credit	**—**	—	112.4
Equity in earnings of affiliates less than dividends received	**9.1**	14.1	15.5
Derivative contracts classified as financing activities	**8.8**	186.0	1,138.3
Changes in working capital			
Accounts receivable, excluding margin	**(268.8)**	(236.5)	543.3
Derivative assets and liabilities, excluding collateral	**775.3**	449.9	425.3
Net collateral and margin	**(245.0)**	44.2	1,522.8
Materials, supplies, and fuel stocks	**34.7**	0.1	220.6
Other current assets	**5.5**	(150.0)	217.2
Accounts payable	**(201.4)**	80.0	(1,105.0)
Liability for unrecognized tax benefits	**(40.8)**	(66.6)	102.1
Accrued taxes and other current liabilities	**(96.2)**	(1,028.4)	788.8
Other	**(67.8)**	11.7	149.3
Net cash provided by operating activities	**1,254.4**	511.3	4,390.8
Cash Flows From Investing Activities			
Investments in property, plant and equipment	**(1,106.8)**	(1,050.3)	(1,529.7)
Asset acquisitions and business combinations, net of cash acquired	**(1,501.9)**	(445.8)	(41.1)
Investments in nuclear decommissioning trust fund securities	**—**	—	(385.2)
Proceeds from nuclear decommissioning trust fund securities	**—**	—	366.5
Investments in joint ventures	**—**	—	(201.6)
Proceeds from sale of 49.99% membership interest in CENG	**—**	—	3,528.7
Proceeds from U. S. Department of Energy grant	**40.6**	54.7	—
Proceeds from sales of investments and other assets	**105.8**	244.0	88.3
Proceeds from investment tax credits and grants related to renewable energy investments	**81.7**	56.5	—
Payment for issuance of loans receivable	**(75.0)**	—	—
Proceeds from repayment of loans receivable	**45.0**	—	—
Contract and portfolio acquisitions	**(3.7)**	(208.3)	(2,153.7)
Decrease (increase) in restricted funds	**51.8**	(60.3)	1,003.3
Other	**(17.7)**	(35.7)	0.1
Net cash (used in) provided by investing activities	**(2,380.2)**	(1,445.2)	675.6
Cash Flows From Financing Activities			
Net repayment of short-term borrowings	**(12.1)**	(13.6)	(809.7)
Proceeds from issuance of common stock	**21.1**	14.0	33.9
Proceeds from issuance of long-term debt	**564.2**	550.0	136.1
Common stock dividends paid	**(182.6)**	(183.3)	(228.0)
BGE preference stock dividends paid	**(13.2)**	(13.2)	(13.2)
Proceeds from contract and portfolio acquisitions	**2.0**	52.2	2,263.1
Repayment of long-term debt	**(305.3)**	(664.5)	(1,986.8)
Derivative contracts classified as financing activities	**(8.8)**	(186.0)	(1,138.3)
Debt and credit facility costs	**(3.2)**	(32.8)	(98.4)
Other	**(0.3)**	(0.4)	12.7
Net cash provided by (used in) financing activities	**61.8**	(477.6)	(1,828.6)
Net (Decrease) Increase in Cash and Cash Equivalents	**(1,064.0)**	(1,411.5)	3,237.8
Cash and Cash Equivalents at Beginning of Year	**2,028.5**	3,440.0	202.2
Cash and Cash Equivalents at End of Year	**$ 964.5**	$ 2,028.5	$ 3,440.0
Other Cash Flow Information:			
Cash paid during the year for:			
Interest (net of amounts capitalized)	**$ 265.3**	$ 289.5	$ 369.5
Income taxes	**$ (66.7)**	$ 1,044.2	$ 57.1

See Notes to Consolidated Financial Statements.

Certain prior-year amounts have been reclassified to conform with the current year's presentation.

CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDERS' EQUITY AND COMPREHENISVE INCOME (LOSS)
Constellation Energy Group, Inc. and Subsidiaries

Years Ended December 31, 2011, 2010, and 2009	Common Stock Shares	Common Stock Amount	Retained Earnings	Accumulated Other Comprehensive Loss	Noncontrolling Interests	Total Amount
	(Dollar amounts in millions, number of shares in thousands)					
Balance at December 31, 2008	199,129	$3,164.5	$2,228.7	$ (2,211.8)	$ 210.1	$3,391.5
Contribution from noncontrolling interest					8.0	8.0
Other noncontrolling interest					0.4	0.4
Comprehensive Income						
Net income			4,443.4		60.0	4,503.4
Other comprehensive income						
Hedging instruments:						
Reclassification of net losses on hedging instruments from OCI to net income, net of taxes of $(898.5)				1,499.4		1,499.4
Net unrealized loss on hedging instruments, net of taxes of $251.2				(474.7)		(474.7)
Available-for-sale securities:						
Reclassification of net losses on securities from OCI to net income, net of taxes of $(24.6)				25.4		25.4
Net unrealized gains on securities, net of taxes of $(78.2)				77.7		77.7
Defined benefit plans:						
Prior service cost arising during period, net of taxes of $1.0				(1.5)		(1.5)
Net gains arising during period, net of taxes of $(23.9)				26.9		26.9
Amortization of net actuarial loss, prior service cost, and transition obligation included in net periodic benefit cost, net of taxes of $(19.8)				30.3		30.3
Deconsolidation of CENG joint venture:						
Net unrealized gains on nuclear decommissioning trust funds, net of taxes of $125.3				(125.3)		(125.3)
Net unrealized losses on defined benefit plans, net of taxes of $(94.6)				138.0		138.0
Net unrealized gains on foreign currency translation, net of taxes of $(2.7)				7.1		7.1
Other comprehensive income—equity investment in CENG, net of taxes of $(11.7)				12.9		12.9
Other comprehensive income related to other equity method investees, net of taxes of $(1.3)				2.1		2.1
Total Comprehensive Income			4,443.4	1,218.3	60.0	5,721.7
BGE preference stock dividends					(13.2)	(13.2)
Common stock dividend declared ($0.96 per share)			(192.2)			(192.2)
Common stock issued and share-based awards	1,856	65.1	(18.9)			46.2
Balance at December 31, 2009	200,985	3,229.6	6,461.0	(993.5)	265.3	8,962.4
Sale of noncontrolling interest					(17.6)	(17.6)
Distribution from noncontrolling interest					(6.3)	(6.3)
Other noncontrolling interest activity					(0.2)	(0.2)
Comprehensive Income (Loss)						
Net (loss) income			(982.6)		50.8	(931.8)
Other comprehensive income (loss)						
Hedging instruments:						
Reclassification of net losses on hedging instruments from OCI to net income, net of taxes of $(347.5)				582.4		582.4
Net unrealized loss on hedging instruments, net of taxes of $134.6				(233.2)		(233.2)
Available-for-sale securities:						
Reclassification of net gains on securities from OCI to net income, net of taxes of $0.1				(0.1)		(0.1)
Net unrealized gains on securities, net of taxes of $(0.1)				0.1		0.1
Defined benefit plans:						
Prior service cost arising during period, net of taxes of $(1.1)				1.6		1.6
Transition obligation arising during the period, net of taxes of $(0.2)				0.4		0.4
Net losses arising during period, net of taxes of $31.3				(56.6)		(56.6)
Amortization of net actuarial loss, prior service cost, and transition obligation included in net periodic benefit cost, net of taxes of $(15.5)				22.7		22.7
Net unrealized losses on foreign currency translation, net of taxes of $2.2				(6.2)		(6.2)
Other comprehensive income—equity investment in CENG, net of taxes of $(14.1)				9.6		9.6
Other comprehensive loss related to other equity method investees, net of taxes of $0.3				(0.5)		(0.5)
Total Comprehensive Income (Loss)			(982.6)	320.2	50.8	(611.6)

BGE preference stock dividends					(13.2)	(13.2)
Common stock dividend declared ($0.96 per share)			(193.8)			(193.8)
Common stock issued and share-based awards	1,304	77.4	(13.8)			63.6
Common stock returned in connection with comprehensive agreement with EDF	(2,500)	(75.3)				(75.3)
Balance at December 31, 2010	199,789	3,231.7	5,270.8	(673.3)	278.8	8,108.0

See Notes to Consolidated Financial Statements.

Years Ended December 31, 2011, 2010, and 2009	Common Stock Shares	Common Stock Amount	Retained Earnings	Accumulated Other Comprehensive Loss	Noncontrolling Interests	Total Amount
	(Dollar amounts in millions, number of shares in thousands)					
Balance at December 31, 2010	199,789	$3,231.7	$5,270.8	$ (673.3)	$ 278.8	$8,108.0
Noncontrolling interest activity					**7.8**	**7.8**
Comprehensive Income (Loss)						
Net loss			**(340.3)**		**33.5**	**(306.8)**
Other comprehensive income (loss)						
Hedging instruments:						
Reclassification of net losses on hedging instruments from OCI to net income, net of taxes of $(106.4)				**180.8**		**180.8**
Net unrealized loss on hedging instruments, net of taxes of $210.7				**(346.0)**		**(346.0)**
Available-for-sale securities:						
Net unrealized losses on securities, net of taxes of $0.3				**(0.6)**		**(0.6)**
Defined benefit plans:						
Prior service cost arising during period, net of taxes of $0.3				**(0.5)**		**(0.5)**
Net losses arising during period, net of taxes of $68.8				**(105.9)**		**(105.9)**
Amortization of net actuarial loss, prior service cost, and transition obligation included in net periodic benefit cost, net of taxes of $(19.8)				**29.2**		**29.2**
Net unrealized losses on foreign currency translation, net of taxes of $—				**(1.5)**		**(1.5)**
Other comprehensive loss—equity investment in CENG, net of taxes of $4.1				**(8.7)**		**(8.7)**
Other comprehensive loss related to other equity method investees, net of taxes of $6.0				**(9.8)**		**(9.8)**
Total Comprehensive Income (Loss)			**(340.3)**	**(263.0)**	**33.5**	**(569.8)**
BGE preference stock dividends					**(13.2)**	**(13.2)**
Common stock dividend declared ($0.96 per share)			**(192.4)**			**(192.4)**
Common stock issued and share-based awards	**1,897**	**60.5**	**(0.1)**			**60.4**
Balance at December 31, 2011	**201,686**	**$3,292.2**	**$4,738.0**	**$ (936.3)**	**$ 306.9**	**$7,400.8**

See Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF INCOME
Baltimore Gas and Electric Company and Subsidiaries

Year Ended December 31,	**2011**	2010	2009
		(In millions)	
Revenues			
Electric revenues	**$2,321.4**	$2,752.3	$2,820.7
Gas revenues	**671.7**	709.4	758.3
Total revenues	**2,993.1**	3,461.7	3,579.0
Expenses			
Operating expenses			
Electricity purchased for resale	**836.5**	1,252.9	1,217.4
Electricity purchased for resale from affiliate	**348.2**	428.0	623.5
Gas purchased for resale	**334.2**	387.5	449.9
Operations and maintenance	**551.5**	484.5	433.7
Operations and maintenance from affiliate	**115.3**	121.6	126.2
Merger costs	**30.3**	—	—
Impairment losses and other costs	**—**	—	20.0
Depreciation and amortization	**272.1**	249.2	262.1
Taxes other than income taxes	**190.2**	183.8	177.8
Total expenses	**2,678.3**	3,107.5	3,310.6
Income from Operations	**314.8**	354.2	268.4
Other Income	**21.0**	20.8	25.4
Fixed Charges			
Interest expense	**133.8**	135.8	143.6
Allowance for borrowed funds used during construction	**(7.2)**	(5.5)	(4.3)
Total fixed charges	**126.6**	130.3	139.3
Income Before Income Taxes	**209.2**	244.7	154.5
Income Taxes			
Current	**(71.3)**	(202.0)	(119.8)
Deferred	**145.8**	300.2	184.7
Investment tax credit adjustments	**(1.0)**	(1.1)	(1.1)
Total income taxes	**73.5**	97.1	63.8
Net Income	**135.7**	147.6	90.7
Preference Stock Dividends	**13.2**	13.2	13.2
Net Income Attributable to Common Stock before Noncontrolling Interests	**122.5**	134.4	77.5
Net Loss Attributable to Noncontrolling Interests	**—**	—	7.3
Net Income Attributable to Common Stock	**$ 122.5**	$ 134.4	$ 84.8

See Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS
Baltimore Gas and Electric Company and Subsidiaries

At December 31,	**2011**	2010
	(In millions)	
Assets		
Current Assets		
Cash and cash equivalents	**$ 48.6**	$ 50.0
Accounts receivable (net of allowance for uncollectibles of **$37.1** and $34.9, respectively)	**323.0**	351.4
Accounts receivable, unbilled (net of allowance for uncollectibles of **$0.6** and $1.0, respectively)	**193.9**	268.8
Accounts receivable, affiliated companies	**1.7**	1.1
Income taxes receivable, net	**21.2**	55.9
Fuel stocks	**73.8**	66.5
Materials and supplies	**33.5**	31.2
Prepaid taxes other than income taxes	**55.7**	51.7
Regulatory assets (net)	**153.7**	78.7
Restricted cash—consolidated variable interest entity	**29.7**	29.5
Other	**13.1**	9.5
Total current assets	**947.9**	994.3
Investments and Other Assets		
Regulatory assets (net)	**341.9**	374.1
Receivable, affiliated company	**514.0**	494.3
Other	**53.0**	52.2
Total investments and other assets	**908.9**	920.6
Utility Plant		
Plant in service		
Electric	**5,483.0**	5,127.9
Gas	**1,386.9**	1,323.0
Common	**414.6**	507.8
Total plant in service	**7,284.5**	6,958.7
Accumulated depreciation	**(2,464.8)**	(2,449.3)
Net plant in service	**4,819.7**	4,509.4
Construction work in progress	**298.4**	232.9
Plant held for future use	**12.1**	10.1
Net utility plant	**5,130.2**	4,752.4
Total Assets	**$ 6,987.0**	$ 6,667.3

See Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS
Baltimore Gas and Electric Company and Subsidiaries

At December 31,	2011	2010
	(In millions)	
Liabilities and Equity		
Current Liabilities		
Current portion of long-term debt	**$ 109.5**	$ 22.0
Current portion of long-term debt—consolidated variable interest entity	**63.0**	59.7
Accounts payable	**209.6**	252.9
Accounts payable, affiliated companies	**66.1**	84.9
Customer deposits	**84.0**	78.9
Deferred income taxes	**59.0**	30.1
Accrued taxes	**15.9**	19.0
Accrued interest	**40.8**	41.4
Liability for uncertain tax positions	**10.4**	62.8
Accrued expenses and other	**81.3**	58.3
Total current liabilities	**739.6**	710.0
Deferred Credits and Other Liabilities		
Deferred income taxes	**1,484.2**	1,354.9
Payable, affiliated company	**253.0**	250.8
Deferred investment tax credits	**7.7**	8.4
Other	**15.9**	20.1
Total deferred credits and other liabilities	**1,760.8**	1,634.2
Long-term Debt		
Rate stabilization bonds—consolidated variable interest entity	**394.6**	454.4
Other long-term debt	**1,709.6**	1,431.5
6.20% deferrable interest subordinated debentures due October 15, 2043 to wholly owned BGE Capital Trust II relating to trust preferred securities	**257.7**	257.7
Unamortized discount and premium	**(3.5)**	(2.0)
Current portion of long-term debt	**(109.5)**	(22.0)
Current portion of long-term debt—consolidated variable interest entity	**(63.0)**	(59.7)
Total long-term debt	**2,185.9**	2,059.9
Equity		
Common shareholder's equity	**2,110.7**	2,073.2
Preference stock not subject to mandatory redemption	**190.0**	190.0
Total equity	**2,300.7**	2,263.2
Commitments, Guarantees, and Contingencies (see Note 12)		
Total Liabilities and Equity	**$6,987.0**	$6,667.3

See Notes to Consolidated Financial Statements.

Certain prior-year amounts have been reclassified to conform with the current year's presentation.

CONSOLIDATED STATEMENTS OF CASH FLOWS
Baltimore Gas and Electric Company and Subsidiaries

Year Ended December 31,	**2011**	2010	2009
		(In millions)	
Cash Flows From Operating Activities			
Net income	**$ 135.7**	$ 147.6	$ 90.7
Adjustments to reconcile to net cash provided by operating activities			
Depreciation and amortization	**272.1**	249.2	262.1
Other amortization	**7.3**	5.2	9.2
Deferred income taxes	**145.8**	300.2	184.7
Investment tax credit adjustments	**(1.0)**	(1.1)	(1.1)
Deferred fuel costs	**5.0**	67.4	68.9
Deferred storm costs	**(15.5)**	—	—
Defined benefit plan expenses	**35.7**	36.0	32.7
Allowance for equity funds used during construction	**(15.1)**	(10.5)	(8.2)
Accrual of residential customer rate credit	**—**	—	112.4
Impairment losses and other costs	**—**	—	20.0
Changes in:			
Accounts receivable	**103.4**	(57.6)	(5.1)
Accounts receivable, affiliated companies	**(0.6)**	14.3	(11.1)
Materials, supplies, and fuel stocks	**(9.6)**	8.0	76.4
Income taxes receivable, net	**34.7**	(55.9)	—
Other current assets	**(87.6)**	(6.6)	(10.2)
Accounts payable	**(43.3)**	87.5	(65.0)
Accounts payable, affiliated companies	**(18.8)**	(13.4)	1.3
Other current liabilities	**15.3**	(121.5)	62.7
Long-term receivables and payables, affiliated companies	**(53.0)**	(200.8)	(197.8)
Regulatory assets, net	**9.9**	(64.3)	(44.4)
Other	**(89.2)**	(64.9)	67.6
Net cash provided by operating activities	**431.2**	318.8	645.8
Cash Flows From Investing Activities			
Utility construction expenditures (excluding equity portion of allowance for funds used during construction)	**(588.0)**	(551.5)	(372.6)
Proceeds from U.S. Department of Energy grant	**40.6**	54.7	—
Change in cash pool at parent	**—**	314.7	(165.9)
Proceeds from sales of investments and other assets	**—**	20.9	—
Increase in restricted funds	**(0.2)**	(5.2)	(0.6)
Net cash used in investing activities	**(547.6)**	(166.4)	(539.1)
Cash Flows From Financing Activities			
Net repayment of short-term borrowings	**—**	(46.0)	(324.0)
Proceeds from issuance of long-term debt	**300.0**	—	—
Repayment of long-term debt	**(81.7)**	(56.5)	(90.0)
Debt issuance costs	**(5.1)**	(0.3)	(0.5)
Contribution from noncontrolling interest	**—**	—	8.0
Preference stock dividends paid	**(13.2)**	(13.2)	(13.2)
(Distribution to) contribution from parent	**(85.0)**	—	315.9
Net cash provided by (used in) financing activities	**115.0**	(116.0)	(103.8)
Net (Decrease) Increase in Cash and Cash Equivalents	**(1.4)**	36.4	2.9
Cash and Cash Equivalents at Beginning of Year	**50.0**	13.6	10.7
Cash and Cash Equivalents at End of Year	**$ 48.6**	$ 50.0	$ 13.6
Other Cash Flow Information:			
Cash paid (received) during the year for:			
Interest (net of amounts capitalized)	**$ 122.3**	$ 127.9	$ 136.9
Income taxes	**$ (53.6)**	$ (76.0)	$(250.9)

See Notes to Consolidated Financial Statements.

Certain prior-year amounts have been reclassified to conform with the current year's presentation.

Notes to Consolidated Financial Statements

1 Significant Accounting Policies

Nature of Our Business

Constellation Energy Group, Inc. (Constellation Energy) is an energy company that conducts its business through various subsidiaries organized around three business segments: a generation business (Generation), a customer supply business (NewEnergy), and Baltimore Gas and Electric Company (BGE). Our Generation and NewEnergy businesses are competitive providers of energy solutions for a variety of customers. BGE is a regulated electric transmission and distribution utility company and a regulated gas distribution utility company with a service territory that covers the City of Baltimore and all or part of ten counties in central Maryland. We describe our operating segments in *Note 3*.

This report is a combined report of Constellation Energy and BGE. References in this report to "we" and "our" are to Constellation Energy and its subsidiaries. References in this report to the "regulated business(es)" are to BGE.

Pending Merger with Exelon Corporation

In April 2011, Constellation Energy entered into an Agreement and Plan of Merger with Exelon Corporation (Exelon). We discuss the pending merger in more detail in *Note 15*.

Consolidation Policy

We use three different accounting methods to report our investments in our subsidiaries or other companies: consolidation, the equity method, and the cost method.

Consolidation

We use consolidation for two types of entities:

- subsidiaries in which we own a majority of the voting stock and exercise control over the operations and policies of the company, and
- variable interest entities (VIEs) for which we are the primary beneficiary, which means that we have a controlling financial interest in a VIE. We discuss our investments in VIEs in more detail in *Note 4*.

Consolidation means that we combine the accounts of these entities with our accounts. Therefore, our consolidated financial statements include our accounts, the accounts of our majority-owned subsidiaries that are not VIEs, and the accounts of VIEs for which we are the primary beneficiary. We have consolidated four VIEs for which we are the primary beneficiary. We eliminate all intercompany balances and transactions when we consolidate these accounts.

The Equity Method

We usually use the equity method to report investments, corporate joint ventures, partnerships, and affiliated companies where we hold a significant influence, which generally approximates a 20% to 50% voting interest. Under the equity method, we report:

- our interest in the entity as an investment in our Consolidated Balance Sheets, and
- our percentage share of the earnings from the entity in our Consolidated Statements of Income (Loss). If our carrying value of the investment differs from our share of the investee's equity, we recognize this basis difference as an adjustment of our share of the investee's earnings.

The only time we do not use this method is if we can exercise control over the operations and policies of the company. If we have control, accounting rules require us to use consolidation.

The Cost Method

We usually use the cost method if we hold less than a 20% voting interest in an investment. Under the cost method, we report our investment at cost in our Consolidated Balance Sheets. We recognize income only to the extent that we receive dividends or distributions. The only time we do not use this method is when we can exercise significant influence over the operations and policies of the company. If we have significant influence, accounting rules require us to use the equity method.

Sale of Subsidiary Ownership Interests

We may sell portions of our ownership interests in a subsidiary's stock. We treat sales of subsidiary stock as an equity transaction and do not recognize any gains or losses on the transaction as long as we retain a controlling financial interest.

When we sell ownership interests in our subsidiaries and do not retain a controlling financial interest, we deconsolidate that subsidiary. Upon deconsolidation, we recognize a gain or loss for the difference between the sum of the fair value of any consideration received and the fair value of our retained investment and the carrying amount of the former subsidiary's assets and liabilities.

On November 6, 2009, we completed the sale of a 49.99% membership interest in Constellation Energy Nuclear Group LLC and affiliates (CENG), our nuclear generation and operation business, to EDF Group and affiliates (EDF). As a result, we ceased to have a controlling financial interest in CENG and deconsolidated CENG at that time. We account for our retained interest in CENG using the equity method. See *Note 2* for the gain recognized in 2009 on our sale of a 49.99% interest in CENG to EDF.

Regulation of Electric and Gas Business

The Maryland Public Service Commission (Maryland PSC) and the Federal Energy Regulatory Commission (FERC) provide the final determination of the rates we charge our customers for our regulated businesses. Generally, we follow the same accounting policies and practices used by nonregulated companies for financial reporting under accounting principles generally accepted in the United States of America. However, sometimes the Maryland PSC or the FERC orders an accounting treatment different from that used by nonregulated companies to determine the rates we charge our customers.

When this happens, we and BGE must defer (include as an asset or liability in the Consolidated Balance Sheets and exclude from Consolidated Statements of Income (Loss)) certain regulated business expenses and income as regulatory assets and liabilities. We and BGE have recorded these regulatory assets and liabilities in the Consolidated Balance Sheets.

We summarize and discuss regulatory assets and liabilities further in *Note 6*.

Use of Accounting Estimates

Management makes estimates and assumptions when preparing financial statements under accounting principles generally accepted in the United States of America. These estimates and assumptions affect various matters, including:

- our revenues and expenses in our Consolidated Statements of Income (Loss) during the reporting periods,
- our assets and liabilities in our Consolidated Balance Sheets at the dates of the financial statements, and
- our disclosure of contingent assets and liabilities at the dates of the financial statements.

These estimates involve judgments with respect to numerous factors that are difficult to predict and are beyond management's control. As a result, actual amounts could materially differ from these estimates.

Reclassifications

We made the following reclassifications:

- We have separately presented "Regulatory assets (net)" that was previously presented within "Other current assets" on our Consolidated Balance Sheets.
- We have separately presented "Accrued interest" that was previously presented within "Accrued expenses and other" on BGE's Consolidated Balance Sheet.
- We have separately presented "Proceeds from U.S. Department of Energy grant" that was previously presented within "Utility construction expenditures" on our, and BGE's, Consolidated Statements of Cash Flows.

Revenues

Sources of Revenue

We earn revenues from the following primary business activities:

- sale of energy and energy-related products, including electricity, natural gas, and other commodities, in nonregulated markets;
- sale and delivery of electricity and natural gas to customers of BGE;
- trading energy and energy-related commodities; and,
- providing other energy-related nonregulated products and services.

We report BGE's revenues from the sale and delivery of electricity and natural gas to its customers as "Regulated electric revenues" and "Regulated gas revenues" in our Consolidated Statements of Income (Loss). We report all other revenues as "Nonregulated revenues."

Revenues from nonregulated activities result from contracts or other sales that generally reflect market prices in effect at the time that we executed the contract or the sale occurred. BGE's revenues from regulated activities reflect provisions of orders of the Maryland PSC and the FERC. In certain cases, these orders require BGE to defer the difference between certain portions of its actual costs and the amount presently billable to customers. BGE records these differences as regulatory assets or liabilities, which we discuss in more detail in *Note 6*. We describe the effects of these orders on BGE's revenues below.

Regulated Electric

BGE provides market-based standard offer electric service to its residential, commercial, and industrial customers. BGE charges these customers standard offer service (SOS) rates that are designed to recover BGE's wholesale power supply costs and include an administrative fee consisting of a shareholder return component and an incremental cost component. Pursuant to Senate Bill 1, the energy legislation enacted in Maryland in June 2006, BGE suspended collection of the shareholder return component of the administrative fee for residential SOS service beginning January 1, 2007 for a 10-year period. However, under an order issued by the Maryland PSC in May 2007, as of June 1, 2007, BGE reinstated collection of the residential return component of the SOS administration charge and began providing all residential electric customers a credit for the return component of the administrative charge. As part of the 2008 Maryland settlement agreement, BGE resumed collection of the shareholder return portion of the residential standard offer service administrative charge from June 1, 2008 through May 31, 2010 without having to rebate it to all residential electric customers. Starting June 1, 2010, BGE is providing all residential electric customers a credit for the residential return component of the administrative charge, which will continue through December 2016.

In May 2010, BGE filed an electric and gas distribution rate case with the Maryland PSC and the Maryland PSC issued an abbreviated order in December 2010. The order authorized BGE to increase electric distribution rates by $31.0 million and was based on an 8.06% rate of return with a 9.86% return on equity and a 52% equity ratio.

BGE defers the difference between certain of its actual costs related to the electric commodity and what it collects from customers under the commodity charge portion of SOS rates in a given period. BGE either bills or refunds its customers the difference in the future.

Regulated Gas

BGE charges its gas customers for the natural gas they purchase from BGE using "gas cost adjustment clauses." Under these clauses, BGE defers the difference between certain of its actual costs related to the gas commodity and what it collects from customers under the commodity charge in a given period for evaluation under a market-based rates incentive mechanism. For each period subject to that mechanism, BGE compares its actual cost of gas to a market index (a measure of the market price of gas for that period) and shares the difference equally between shareholders and customers through an adjustment to the price of gas service in future periods. This sharing mechanism excludes fixed-price contracts which the Maryland PSC requires BGE to procure for at least 10%, but not more than 20%, of forecasted system supply requirements for the November through March period.

In May 2010, BGE filed an electric and gas distribution rate case with the Maryland PSC and the Maryland PSC issued an abbreviated order in December 2010. The order authorized BGE to increase gas distribution rates by $9.8 million and was based on a 7.90% rate of return with a 9.56% return on equity and a 52% equity ratio.

Selection of Accounting Treatment

We determine the appropriate accounting treatment for recognizing revenues based on the nature of the transaction, governing accounting standards and, where required, by applying judgment as to the most transparent presentation of the economics of the underlying transactions. We utilize two primary accounting treatments to recognize and report revenues in our results of operations:

- accrual accounting, including hedge accounting, and
- mark-to-market accounting.

We describe each of these accounting treatments below.

Accrual Accounting

Under accrual accounting, we record revenues in the period when we deliver energy commodities or products, render services, or settle contracts. We generally use accrual accounting to recognize revenues for our sales of electricity, gas, coal, and other commodities as part of our physical delivery activities. We 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 BGE's customers under regulated service tariffs, and spot-market sales, including settlements with independent system operators. We discuss the NPNS election later in this Note under *Derivatives and Hedging Activities*.

However, we also use mark-to-market accounting rather than accrual accounting for recognizing revenue on our competitive retail gas customer supply activities, our fixed quantity competitive retail power customer supply activities for new transactions closed after June 30, 2010, which are managed using economic hedges that we have not designated as cash-flow hedges so as to match the timing of recognition of the earnings impacts of those activities to the greatest extent permissible, and other physical commodity derivatives if we have not designated those contracts as NPNS.

We record accrual revenues from sales of products or services on a gross basis at the contract, tariff, or spot price because we are a principal to the transaction. Accrual revenues also include certain other gains and losses that relate to these activities or for which accrual accounting is required.

We include in accrual revenues the effects of hedge accounting for derivative contracts that qualify as hedges of our sales of products or services. Substantially all of the derivatives that we designate as hedges are cash flow hedges. We recognize the effective portion of hedge gains or losses in revenues during the same period in which we record the revenues from the hedged transaction. We record any hedge ineffectiveness in revenues when it occurs. We discuss our hedge accounting policy in the *Derivatives and Hedging Activities* section later in this Note.

We may make or receive cash payments at the time we assume previously existing power sale agreements for which the contract price differs from current market prices. We also may designate a derivative as NPNS after its inception. We recognize the value of these derivatives in our Consolidated Balance Sheets as an "Unamortized energy contract" asset or liability. We amortize these assets and liabilities into revenues based on the present value of the underlying cash flows provided by the contracts.

The following table summarizes the primary components of accrual revenues:

Component of Accrual Revenues	Nonregulated Physical Energy Delivery	Activity Regulated Electricity and Gas Sales	Other Nonregulated Products and Services
Gross amounts receivable for sales of products or services based on contract, tariff, or spot price	X	X	X
Reclassification of net gains/losses on cash flow hedges from AOCI	X		
Ineffective portion of net gains/losses on cash flow hedges	X		
Amortization of acquired energy contract assets or liabilities	X		
Recovery or refund of deferred SOS and gas cost adjustment clause regulatory assets/liabilities		X	

Mark-to-Market Accounting

We record revenues using the mark-to-market method of accounting for transactions under derivative contracts for which we are not permitted, or do not elect, to use accrual accounting or hedge accounting. These mark-to-market transactions primarily relate to our risk management and trading activities, our competitive retail gas customer supply activities, and economic hedges of other accrual activities. Mark-to-market revenues include:

- origination gains or losses on new transactions,
- unrealized gains and losses from changes in the fair value of open contracts,
- net gains and losses from realized transactions, and
- changes in valuation adjustments.

Under the mark-to-market method of accounting, we record any inception fair value of these contracts as derivative assets and liabilities at the time of contract execution. We record subsequent changes in the fair value of these derivative assets and liabilities on a net basis in "Nonregulated revenues" in our Consolidated Statements of Income (Loss). We discuss our mark-to-market accounting policy in the *Derivatives and Hedging Activities* section later in this Note.

Fuel and Purchased Energy Expenses

Sources of Fuel and Purchased Energy Expenses

We incur fuel and purchased energy costs for:

- the fuel we use to generate electricity at our power plants,

- purchases of electricity from others, and
- purchases of natural gas, coal, and other fuel types that we resell.

We report these costs in "Fuel and purchased energy expenses" in our Consolidated Statements of Income (Loss). We also include certain fuel-related direct costs, such as ancillary services purchased from independent system operators, transmission costs, brokerage fees, and freight costs in the same category in our Consolidated Statements of Income (Loss).

Fuel and purchased energy costs from nonregulated activities result from contracts or other purchases that generally reflect market prices in effect at the time that we executed the contract or the purchase occurred. BGE's costs of electricity and gas for resale under regulated activities reflect actual costs of purchases, adjusted to reflect provisions of orders of the Maryland PSC and the FERC. In certain cases, these orders require BGE to defer the difference between certain portions of its actual costs and the amount presently billable to customers. BGE records these differences as regulatory assets or liabilities, which we discuss in more detail in *Note 6*. We describe the effects of these orders on BGE's fuel and purchased energy expense below.

Regulated Electric

BGE provides market-based standard offer electric service to its residential, commercial, and industrial customers. BGE charges these customers SOS rates that are designed to recover BGE's wholesale power supply costs and include an administrative fee consisting of a shareholder return component and an incremental cost component. Starting June 1, 2010, BGE is providing all residential electric customers a credit for the residential return component of the administrative charge, which will continue through December 2016.

BGE defers the difference between certain of its actual costs related to the electric commodity and what it collects from customers under the commodity charge portion of SOS rates in a given period. BGE either bills or refunds its customers the difference in the future and includes amortization of the deferred amounts in fuel and purchased energy expense. Therefore, BGE does not earn a profit on the cost of fuel and purchased energy because its expense approximates the amount of the related commodity charge included in revenues for the period, reflecting actual costs adjusted for the effects of the regulatory deferral mechanism.

Regulated Gas

BGE charges its gas customers for the natural gas they purchase from BGE using "gas cost adjustment clauses." These clauses include a market-based rates incentive mechanism that requires BGE to compare its actual cost of gas to a market index (a measure of the market price of gas for that period) and share the difference equally between shareholders and customers. This sharing mechanism excludes fixed-price contracts which the Maryland PSC requires BGE to procure for at least 10%, but not more than 20%, of forecasted system supply requirements for the November through March period.

BGE defers the difference between the portion of its actual gas commodity costs subject to the market-based rates incentive mechanism and what it collects from customers under the commodity charge in a given period. BGE either bills or refunds its customers the portion of this difference to which they are entitled through an adjustment to the price of gas service in future periods and includes amortization of the deferred amounts in fuel and purchased energy expense.

Selection of Accounting Treatment

We determine the appropriate accounting treatment for fuel and purchased energy costs based on the nature of the transaction, governing accounting standards and, where required, by applying judgment as to the most transparent presentation of the economics of the underlying transactions. We utilize two primary accounting treatments to recognize and report these costs in our Consolidated Statements of Income (Loss):

- accrual accounting, including hedge accounting, and
- mark-to-market accounting.

We describe each of these accounting treatments below.

Accrual Accounting

Under accrual accounting, we record fuel and purchased energy expenses in the period when we consume the fuel or purchase the electricity or other commodity for resale. We use accrual accounting to recognize substantially all of our fuel and purchased energy expenses as part of our physical delivery activities. We make these purchases using a variety of instruments, including non-derivative transactions, derivatives that qualify for and are designated as NPNS, and spot-market purchases, including settlements with independent system operators. These transactions also include power purchase agreements that qualify as operating leases, for which fuel and purchased energy consists of both fixed capacity payments and variable payments based on the actual output of the plants. We discuss the NPNS election later in this Note under *Derivatives and Hedging Activities*.

In certain cases, we use mark-to-market accounting rather than accrual accounting for recognizing fuel and purchased energy expenses on physical commodity derivatives if we have not designated those contracts as NPNS.

We include in accrual fuel and purchased energy expenses the effects of hedge accounting for derivative contracts that qualify as hedges of our fuel and purchased energy costs. Substantially all of the derivatives that we designate as hedges are cash flow hedges. We recognize the effective portion of hedge gains or losses in fuel and purchased energy expenses during the same period in which we record the costs from the hedged transaction. We record any hedge ineffectiveness in expense when it occurs. We discuss our use of hedge accounting in the *Derivatives and Hedging Activities* section later in this Note.

We may make or receive cash payments at the time we assume previously existing power purchase agreements or other contracts for which the contract price differs from current market prices. We recognize the cash payment at inception in our Consolidated Balance Sheets as an “Unamortized energy contract” asset or liability. We amortize these assets and liabilities into fuel and purchased energy expenses based on the present value of the underlying cash flows provided by the contracts.

The following table summarizes the primary components of accrual purchased fuel and energy expense:

		Activity	
Component of Accrual Fuel and Purchased Energy Expense	**Nonregulated Physical Energy Delivery**	**Regulated Electricity and Gas Sales**	**Other Nonregulated Products and Services**
Actual costs of fuel and purchased energy	X	X	X
Reclassification of net gains/losses on cash flow hedges from AOCI	X		
Ineffective portion of net gains/losses on cash flow hedges	X		
Amortization of acquired energy contract assets or liabilities	X		
Deferral or amortization of deferred SOS and gas cost adjustment clause regulatory assets/liabilities		X	

Mark-to-Market Accounting

We record fuel and purchased energy expenses using the mark-to-market method of accounting for transactions under derivative contracts for which we are not permitted, or do not elect, to use accrual accounting or hedge accounting in order to match the earnings impacts of those activities to the greatest extent permissible. These mark-to-market transactions relate to our physical international coal purchase contracts in 2009 and 2008. Mark-to-market costs include:

- unrealized gains and losses from changes in the fair value of open contracts,
- net gains and losses from realized transactions, and
- changes in valuation adjustments.

Under the mark-to-market method of accounting, we record any inception fair value of these contracts as derivative assets and liabilities at the time of contract execution. We record subsequent changes in the fair value of these derivative assets and liabilities on a net basis in “Fuel and purchased energy expense” in our Consolidated Statements of Income (Loss). We discuss our mark-to-market accounting policy in the *Derivatives and Hedging Activities* section later in this Note.

Derivatives and Hedging Activities

We engage in electricity, natural gas, coal, emission allowances, and other commodity marketing and risk management activities as part of our NewEnergy business. In order to manage our exposure to commodity price fluctuations, we enter into energy and energy-related derivative contracts traded in the over-the-counter markets or on exchanges. These contracts include:

- forward physical purchase and sales contracts,
- futures contracts,
- financial swaps, and
- option contracts.

We use interest rate swaps to manage our interest rate exposures associated with new debt issuances, to manage our exposure to fluctuations in interest rates on variable rate debt, and to optimize the mix of fixed and floating-rate debt. We use foreign currency swaps to manage our exposure to foreign currency exchange rate fluctuations.

<u>Selection of Accounting Treatment</u>

We account for derivative instruments and hedging activities in accordance with several possible accounting treatments that meet all of the requirements of the accounting standard. Mark-to-market is the default accounting treatment for all derivatives unless they qualify, and we specifically designate them, for one of the other accounting treatments. Derivatives designated for any of the other elective accounting treatments must meet specific, restrictive criteria, both at the time of designation and on an ongoing basis.

The following are permissible accounting treatments for derivatives:

- mark-to-market,
- cash flow hedge,
- fair value hedge, and
- NPNS.

Each of the accounting treatments for derivatives affects our financial statements in substantially different ways as summarized below:

Accounting Treatment	Recognition and Measurement: Balance Sheet	Recognition and Measurement: Income Statement
Mark-to-market	• Derivative asset or liability recorded at fair value	• Changes in fair value recognized in earnings
Cash flow hedge	• Derivative asset or liability recorded at fair value • Effective changes in fair value recognized in accumulated other comprehensive income	• Ineffective changes in fair value recognized in earnings • Amounts in accumulated other comprehensive income reclassified to earnings when the hedged forecasted transaction affects earnings or becomes probable of not occurring
Fair value hedge	• Derivative asset or liability recorded at fair value • Book value of hedged asset or liability adjusted for changes in its fair value	• Changes in fair value recognized in earnings • Changes in fair value of hedged asset or liability recognized in earnings
NPNS (accrual)	• Fair value not recorded • Accounts receivable or accounts payable recorded when derivative settles	• Changes in fair value not recognized in earnings • Revenue or expense recognized in earnings when underlying physical commodity is sold or consumed

Mark-to-Market

We generally apply mark-to-market accounting for risk management and trading activities because changes in fair value more closely reflect the economic performance of the activity. However, we also use mark-to-market accounting for derivatives related to the following physical energy delivery activities:

- our competitive retail gas customer supply activities, which are managed using economic hedges that we have not designated as cash-flow hedges, in order to match the timing of recognition of the earnings impacts of those activities to the greatest extent permissible, and
- economic hedges of activities that require accrual accounting for which the related hedge requires mark-to-market accounting.

We may record origination gains associated with derivatives subject to mark-to-market accounting. Origination gains represent the initial fair value of certain structured transactions that our portfolio management and trading operation executes to meet the risk management needs of our customers. Historically, transactions that result in origination gains have been unique and resulted in individually significant gains from a single transaction. We generally recognize origination gains when we are able to obtain observable market data to validate that the initial fair value of the contract differs from the contract price.

Cash Flow Hedge

We generally elect cash flow hedge accounting for most of the derivatives that we use to hedge market price risk for our physical energy delivery (Generation and NewEnergy businesses) activities because cash flow hedge accounting more closely aligns the timing of earnings recognition, cash flows, and the underlying business activities. We only use fair value hedge accounting on a limited basis.

We use regression analysis to determine whether we expect a derivative to be highly effective as a cash flow hedge prior to electing hedge accounting and also to determine whether all derivatives designated as cash flow hedges have been effective. We perform these effectiveness tests prior to designation for all new hedges and on a daily basis for all existing hedges. We calculate the actual amount of ineffectiveness on our cash flow hedges using the “dollar offset” method, which compares changes in the expected cash flows of the hedged transaction to changes in the value of expected cash flows from the hedge.

We discontinue hedge accounting when our effectiveness tests indicate that a derivative is no longer highly effective as a hedge; when the derivative expires or is sold, terminated or exercised; when the hedged item matures, is sold or repaid; or when we determine that the occurrence of the hedged forecasted transaction is not probable. When we discontinue hedge accounting but continue to hold the derivative, we begin to apply mark-to-market accounting at that time.

NPNS

We elect NPNS accounting for derivative contracts that provide for the purchase or sale of a physical commodity that will be delivered in quantities expected to be used or sold over a reasonable period in the normal course of business. Once we elect NPNS classification for a given contract, we do not subsequently change the election and treat the contract as a derivative using mark-to-market or hedge accounting. However, if we were to determine that a transaction designated as NPNS no longer qualified for the NPNS election, we would have to record the fair value of that contract on the balance sheet at that time and immediately recognize that amount in earnings.

Fair Value

We record mark-to-market and hedge derivatives at fair value, which represents an exit price for the asset or liability from the perspective of a market participant. An exit price is the price at which a market participant could sell an asset or transfer a liability to an unrelated party. While some of our derivatives relate to commodities or instruments for which quoted market prices are available from external sources, many other commodities and related contracts are not actively traded. Additionally, some contracts include quantities and other factors that vary over time. As a result, often we must use modeling techniques to estimate expected future market prices, contract quantities, or both in order to determine fair value.

The prices, quantities, and other factors we use to determine fair value reflect management's best estimates of inputs a market participant would consider. We record valuation adjustments to reflect uncertainties associated with estimates inherent in the determination of fair value that are not incorporated in market price information or other market-based estimates we use to determine fair value. To the extent possible, we utilize market-based data together with quantitative methods for both measuring the uncertainties for which we record valuation adjustments and determining the level of such adjustments and changes in those levels.

The valuation adjustments we record include the following:

- Close-out adjustment—the estimated cost to close out or sell to a third party open mark-to-market positions. This valuation adjustment has the effect of valuing purchase contracts at the bid price and sale contracts at the offer price.
- Unobservable input valuation adjustment—necessary when we determine fair value for derivative positions using internally developed models that use unobservable inputs due to the absence of observable market information.
- Credit spread adjustment—necessary to reflect the credit-worthiness of each customer (counterparty).

We discuss derivatives and hedging activities as well as how we determine fair value in detail in *Note 13*.

Balance Sheet Netting

We often transact with counterparties under master agreements and other arrangements that provide us with a right of setoff of amounts due to us and from us in the event of bankruptcy or default by the counterparty. We report these transactions on a net basis in our Consolidated Balance Sheets.

We apply balance sheet netting separately for current and noncurrent derivatives. Current derivatives represent the portion of derivative contract cash flows expected to occur within 12 months, and noncurrent derivatives represent the portion of those cash flows expected to occur beyond 12 months. Within each of these categories, we net all amounts due to and from each counterparty under master agreements into a single net asset or liability. We include fair value cash collateral amounts received and posted in determining this net asset and liability amount.

Unamortized Energy Assets and Liabilities

Unamortized energy contract assets and liabilities represent the remaining unamortized balance of non-derivative energy contracts that we acquired, certain contracts which no longer qualify as derivatives due to the absence of a liquid market, or derivatives designated as NPNS that we had previously recorded as "Derivative assets or liabilities." The initial amount recorded represents the fair value of the contract at the time of acquisition or designation, and the balance is amortized over the life of the contract in relation to the present value of the underlying cash flows. The amortization of these values is discussed in the *Revenues* and *Fuel and Purchased Energy Expenses* sections of this Note.

Credit Risk

Credit risk is the loss that may result from counterparty non-performance. We are exposed to credit risk, primarily through our NewEnergy business. We use credit policies to manage our credit risk, including utilizing an established credit approval process, daily monitoring of counterparty limits, employing credit mitigation measures such as margin, collateral (cash or letters of credit) or prepayment arrangements, and using master netting agreements. We measure credit risk as the replacement cost for open energy commodity and derivative positions (both mark-to-market and accrual) plus amounts owed from counterparties for settled transactions. The replacement cost of open positions represents unrealized gains, less any unrealized losses where we have a legally enforceable right of setoff.

We consider a significant concentration of credit risk to be any single obligor or counterparty whose concentration exceeds 10% of total credit exposure. As of December 31, 2011, two counterparties, both large investment grade power cooperatives, together comprised a total exposure concentration of 29%. No counterparties based in a single country other than the United States in aggregate comprise more than 10% of the total exposure of the portfolio.

Equity Investment Earnings (Losses)

We include equity in earnings from our investments in qualifying facilities and power projects, joint ventures, and Constellation Energy Partners LLC (CEP) in "Equity Investment Earnings (Losses)" in our Consolidated Statements of Income (Loss) in the period they are earned. "Equity Investment Earnings (Losses)" also includes any adjustments to amortize the difference, if any, except for goodwill and land, between our cost in an equity method investment and our underlying equity in net assets of the investee at the date of investment.

We consider our investments in generation-related qualifying facilities, power projects, and joint ventures to be integral to our operations.

Taxes

We summarize our income taxes in *Note 10*. BGE and our other subsidiaries record their allocated share of our consolidated federal income tax liability using the percentage complementary method specified in U.S. income tax regulations. Under this method, our subsidiaries are allocated their respective share of consolidated income tax liabilities as well as tax benefits attributable to their losses and credits without taking into account the ability of the subsidiary to utilize the tax benefits on a stand-alone basis. As you read this section, it may be helpful to refer to *Note 10*.

Income Tax Expense

We have two categories of income tax expense—current and deferred. We describe each of these below:

- current income tax expense consists solely of regular tax less applicable tax credits, and
- deferred income tax expense is equal to the changes in the net deferred income tax liability, excluding amounts charged or credited to accumulated other comprehensive income. Our deferred income tax expense is increased or reduced for changes to the “Income taxes recoverable through future rates (net)” regulatory asset (described below) during the year.

Tax Credits

We defer the investment tax credits associated with our regulated business, assets previously held by our regulated business, and any investment tax credits that are convertible to cash grants in our Consolidated Balance Sheets. The investment tax credits that are convertible to cash grants are recorded as a reduction to the carrying value of the underlying property and subsequently amortized evenly to earnings over the life of each underlying property. We reduce current income tax expense in our Consolidated Statements of Income (Loss) for any investment tax credits that are not convertible to cash grants and other tax credits associated with our nonregulated businesses.

Deferred Income Tax Assets and Liabilities

We must report some of our revenues and expenses differently for our financial statements than for income tax return purposes. The tax effects of the temporary differences in these items are reported as deferred income tax assets or liabilities in our Consolidated Balance Sheets. We measure the deferred income tax assets and liabilities using income tax rates that are currently in effect.

A portion of our total deferred income tax liability relates to our regulated business, but has not been reflected in the rates we charge our customers. We refer to this portion of the liability as “Income taxes recoverable through future rates (net).” We have recorded that portion of the net liability as a regulatory asset in our Consolidated Balance Sheets. We discuss this further in *Note 6*.

Interest and Penalties

We recognize interest and penalties related to tax underpayments, assessments, and unrecognized tax benefits in “Income tax expense (benefit)” in our Consolidated Statements of Income (Loss).

Unrecognized Tax Benefits

We recognize in our financial statements the effects of uncertain tax positions if we believe that these positions are “more-likely-than-not” to be realized. We establish liabilities to reflect the portion of those positions we cannot conclude are “more-likely-than-not” to be realized upon ultimate settlement. These are referred to as liabilities for unrecognized tax benefits.

We discuss our unrecognized tax benefits in more detail in *Note 10*.

State and Local Taxes

State and local income taxes are included in “Income tax expense (benefit)” in our Consolidated Statements of Income (Loss).

Taxes Other Than Income Taxes

Taxes other than income taxes primarily include property and gross receipts taxes along with franchise taxes and other non-income taxes, surcharges, and fees.

BGE and our NewEnergy business collect certain taxes from customers such as sales and gross receipts taxes, along with other taxes, surcharges, and fees that are levied by state or local governments on the sale or distribution of gas and electricity. Some of these taxes are imposed on the customer and others are imposed on BGE and our NewEnergy business. Where these taxes, such as sales taxes, are imposed on the customer, we account for these taxes on a net basis with no impact to our Consolidated Statements of Income (Loss). However, where these taxes, such as gross receipts taxes or other surcharges or fees, are imposed on BGE or our NewEnergy business, we account for these taxes on a gross basis. Accordingly, we recognize revenues for these taxes collected from customers along with an offsetting tax expense, which are both included in our Consolidated Statements of Income (Loss). The taxes, surcharges, or fees that are included in revenues were as follows:

Year Ended December 31,	2011	2010	2009
		(In millions)	
Constellation Energy (including BGE)	**$142.7**	$122.2	$106.8
BGE	**82.9**	81.9	76.8

Earnings Per Share

Basic earnings per common share (EPS) is computed by dividing net income (loss) attributable to common stock by the weighted-average number of common shares outstanding for the year. Diluted EPS reflects the potential dilution of common stock equivalent shares that could occur if securities or other contracts to issue common stock were exercised or converted into common stock.

Our dilutive common stock equivalent shares primarily consist of stock options and other stock-based compensation awards. The following table presents stock options that were not dilutive and were excluded from the computation of diluted EPS in each period, as well as the dilutive common stock equivalent shares as follows:

Year Ended December 31,	2011	2010	2009
		(In millions)	
Non-dilutive stock options	4.3	5.6	5.1
Dilutive common stock equivalent shares	1.8	1.6	1.0

As a result of the Company incurring a loss for the years ended December 31, 2011 and 2010, diluted common stock equivalent shares were not included in calculating diluted EPS for these reporting periods.

Stock-Based Compensation

Under our long-term incentive plans, we have granted stock options, performance-based units, service-based units, service-based restricted stock, and equity to officers, key employees, and members of the Board of Directors. We discuss these awards in more detail in *Note 14*.

We recognize compensation expense for all equity-based compensation awards issued to employees that are expected to vest. Equity-based compensation awards include stock options, restricted stock, and any other share-based payments. We recognize compensation cost over the period during which an employee is required to provide service in exchange for the award, which is typically a one to five-year period. We use a forfeiture assumption based on historical experience to estimate the number of awards that are expected to vest during the service period, and ultimately true-up the estimated expense to the actual expense associated with vested awards. We estimate the fair value of stock option awards on the date of grant using the Black-Scholes option-pricing model and we remeasure the fair value of liability awards each reporting period. We do not capitalize any portion of our stock-based compensation.

Cash and Cash Equivalents

All highly liquid investments with original maturities of three months or less are considered cash equivalents.

Accounts Receivable and Allowance for Uncollectibles

Accounts receivable, which includes cash collateral posted in our margin account with third party brokers, are stated at the historical carrying amount net of write-offs and allowance for uncollectibles. We establish an allowance for uncollectibles based on our expected exposure to the credit risk of customers based on a variety of factors.

Materials, Supplies, and Fuel Stocks

We record our fuel stocks, emissions credits, renewable energy credits, coal held for resale, and materials and supplies at the lower of cost or market. We determine cost using the average cost method for our entire inventory.

Restricted Cash

At December 31, 2011, our restricted cash primarily included cash at one of our consolidated variable interest entities, and BGE’s funds restricted for the repayment of the rate stabilization bonds. At December 31, 2010, our restricted cash also included cash held in escrow for the acquisition of the Boston Generating fleet of generating plants.

As of December 31, 2011 and 2010, BGE’s restricted cash primarily represented funds restricted at its consolidated variable interest entity for the repayment of the rate stabilization bonds. We discuss the rate stabilization bonds in more detail in *Note 9*.

Financial Investments

In *Note 4*, we summarize the financial investments that are in our Consolidated Balance Sheets.

We report our debt and equity securities at fair value, and we use either specific identification or average cost to determine their cost for computing realized gains or losses.

Available-for-Sale Securities

We classify our investments in trust assets securing certain executive benefits that are classified as available-for-sale securities.

We include any unrealized gains (losses) on our available-for-sale securities in "Accumulated other comprehensive loss" in our Consolidated Statements of Common Shareholders' Equity and Comprehensive Income (Loss).

Evaluation of Assets for Impairment and Other Than Temporary Decline in Value

Long-Lived Assets

We evaluate certain assets that have long lives (for example, generating property and equipment and real estate) to determine if they are impaired when certain conditions exist. We test our long-lived assets and proved gas properties for recoverability whenever events or changes in circumstances indicate that their carrying amount may not be recoverable.

We determine if long-lived assets and proved gas properties are impaired by comparing their undiscounted expected future cash flows to their carrying amount in our accounting records. Cash flows for long-lived assets are determined at the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets and liabilities. Undiscounted expected future cash flows for proved gas properties include risk-adjusted probable and possible reserves.

We record an impairment loss if the undiscounted expected future cash flows are less than the carrying amount of the asset. The amount of the impairment loss we record equals the difference between the estimated fair value of the asset and its carrying amount in our accounting records.

We evaluate unproved gas producing properties at least annually to determine if they are impaired. Impairment for unproved property occurs if there are no firm plans to continue drilling, lease expiration is at risk, or historical experience necessitates a valuation allowance.

We use our best estimates in making these evaluations and consider various factors, including forward price curves for energy, fuel costs, legislative initiatives, and operating costs. However, actual future market prices and project costs could vary from those used in our impairment evaluations, and the impact of such variations could be material.

Investments

We evaluate our equity method and cost method investments to determine whether or not they are impaired. The standard for determining whether an impairment must be recorded is whether the investment has experienced an "other than a temporary" decline in value.

Additionally, if the projects in which we hold these investments recognize an impairment, we would record our proportionate share of that impairment loss and would evaluate our investment for an other than temporary decline in value.

We continuously monitor issues that potentially could impact future profitability of our equity method investments that own coal, hydroelectric, fuel processing projects, as well as our equity investment in our nuclear joint venture. These issues include environmental and legislative initiatives.

Debt and Equity Securities

We determine whether a decline in fair value of a debt or equity investment below book value is other than temporary. If we determine that the decline in fair value is other than temporary, we write-down the cost basis of the investment to fair value as a new cost basis.

Goodwill and Intangible Assets

Goodwill is the excess of the purchase price of an acquired business over the fair value of the net assets acquired. We do not amortize goodwill. We evaluate goodwill for impairment at least annually or more frequently if events and circumstances indicate the business might be impaired. Goodwill is impaired if the carrying value of the business exceeds fair value. Annually, we estimate the fair value of our businesses using techniques similar to those used to estimate future cash flows for long-lived assets as previously discussed. If the estimated fair value of the business is less than its carrying value, an impairment loss is required to be recognized to the extent that the carrying value of goodwill is greater than its fair value. We amortize intangible assets with finite lives. We discuss the changes in our goodwill and intangible assets in more detail in *Note 5*.

Property, Plant and Equipment, Depreciation, Depletion, Amortization, and Accretion of Asset Retirement Obligations

We report our property, plant and equipment at its original cost, unless impaired.

Original cost includes:

- material and labor,

- contractor costs, and
- construction overhead costs, financing costs, and costs for asset retirement obligations (where applicable).

We own an undivided interest in the Keystone and Conemaugh electric generating plants in Western Pennsylvania, as well as in the Conemaugh substation and transmission line that transports the plants' output to the joint owners' service territories. Our ownership interests in these plants are 20.99% in Keystone and 10.56% in Conemaugh. These ownership interests represented a net investment of $345.2 million at December 31, 2011 and $338.0 million at December 31, 2010. Each owner is responsible for financing its proportionate share of the plants' working funds. Working funds are used for operating expenses and capital expenditures. Operating expenses related to these plants are included in "Operating expenses" in our Consolidated Statements of Income (Loss). Capital costs related to these plants are included in "Nonregulated property, plant and equipment" in our Consolidated Balance Sheets.

The "Nonregulated property, plant and equipment" in our Consolidated Balance Sheets includes nonregulated generation construction work in progress of $162.5 million at December 31, 2011 and $108.3 million at December 31, 2010.

When we retire or dispose of property, plant and equipment, we remove the asset's cost from our Consolidated Balance Sheets. We charge this cost to accumulated depreciation for assets that were depreciated under the group, straight-line method. This includes regulated property, plant and equipment and nonregulated generating assets. For all other assets, we remove the accumulated depreciation and amortization amounts from our Consolidated Balance Sheets and record any gain or loss in our Consolidated Statements of Income (Loss).

The costs of maintenance and certain replacements are charged to "Operating expenses" in our Consolidated Statements of Income (Loss) as incurred.

Our oil and gas exploration and production activities consist of working interests in gas producing fields. We account for these activities under the successful efforts method of accounting. Acquisition, development, and exploration costs are capitalized. Costs of drilling exploratory wells are initially capitalized and later charged to expense if reserves are not discovered or deemed not to be commercially viable. Other exploratory costs are charged to expense when incurred.

Depreciation and Depletion Expense

We compute depreciation for our generating, electric transmission and distribution, and gas distribution facilities. We compute depletion for our oil and gas exploitation and production activities. Depreciation and depletion are determined using the following methods:

- the group straight-line method using rates averaging approximately 3.2% per year for our non-solar generating assets,
- the individual straight-line method using a 30-year life for solar generating assets,
- the group straight-line method, approved by the Maryland PSC, applied to the average investment, adjusted for anticipated costs of removal less salvage, in classes of depreciable property based on an average rate of approximately 2.8% per year for our regulated business, or
- the units-of-production method over the remaining life of the estimated proved reserves at the field level for acquisition costs and over the remaining life of proved developed reserves at the field level for development costs. The estimates for gas reserves are based on internal calculations.

Other assets are depreciated primarily using the straight-line method and the following estimated useful lives:

Asset	Estimated Useful Lives
Building and improvements	3 - 50 years
Office equipment and furniture	3 - 21 years
Transportation equipment	5 - 15 years
Computer software	3 - 15 years

Amortization Expense

Amortization is an accounting process of reducing an asset amount in our Consolidated Balance Sheets over a period of time that approximates the asset's useful life. When we reduce amounts in our Consolidated Balance Sheets, we record amortization expense in our Consolidated Statements of Income (Loss). We discuss the types of assets that we amortize and the periods over which we amortize them in more detail in *Note 5*.

Accretion Expense

We recognize an estimated liability for legal obligations and legal obligations conditional upon a future event associated with the retirement of tangible long-lived assets. Our conditional asset retirement obligations relate primarily to asbestos removal at certain of our generating facilities.

From time to time, we will perform studies to update our asset retirement obligations. We record a liability when we are able to reasonably estimate the fair value of any future legal obligations associated with retirement that have been incurred and capitalize a corresponding amount as part of the book value of the related long-lived assets.

The increase in the capitalized cost is included in determining depreciation expense over the estimated useful lives of these assets. Since the fair value of the asset retirement obligations is determined using a present value approach, accretion of the liability due to the passage of time is recognized each period to "Accretion of asset retirement obligations" in our Consolidated Statements of Income (Loss) until the settlement of the liability. We record a gain or loss when the liability is settled after retirement for any difference between the accrued liability and actual costs.

Capitalized Interest and Allowance for Funds Used During Construction

Capitalized Interest

Our nonregulated businesses capitalize interest costs for costs incurred to finance our power plant construction projects, real estate developed for internal use, and other capital projects.

Allowance for Funds Used During Construction (AFC)

BGE finances its construction projects with borrowed funds and equity funds. BGE is allowed by the Maryland PSC and the FERC to record the costs of these funds as part of the cost of construction projects in its Consolidated Balance Sheets. BGE does this through the AFC, which it calculates using rates authorized by the Maryland PSC and the FERC. BGE bills its customers for the AFC plus a return after the utility property is placed in service.

The AFC rates for 2011 were 8.06% for electric distribution plant, 8.92% for electric transmission plant, 7.90% for gas plant, and 8.13% for common plant. BGE compounds AFC annually.

Long-Term Debt and Credit Facilities

We defer all costs related to the issuance of long-term debt and credit facilities. These costs include underwriters' commissions, discounts or premiums, other costs such as external legal, accounting, and regulatory fees, and printing costs. We amortize costs related to long-term debt into interest expense over the life of the debt. We amortize costs related to credit facilities to other (expenses) income over the terms of the facilities.

In addition to the fees that are paid upfront for credit facilities, we also incur ongoing fees related to these facilities. We record the ongoing fees in other (expense) income, and we record interest incurred on cash draws in interest expense.

When BGE incurs gains or losses on debt that it retires prior to maturity, it amortizes those gains or losses over the remaining original life of the debt in accordance with regulatory requirements.

Accounting Standards Issued

Asset and Liability Netting

In December 2011, the Financial Accounting Standards Board (FASB) issued updated disclosure requirements regarding the netting of certain assets and liabilities, including derivatives. Entities will be required to disclose both gross information and net information about instruments and transactions eligible for offset in the balance sheet and instruments and transactions subject to master netting agreements. The new requirements will be effective for us as of January 1, 2013. The adoption of this update will not impact our, or BGE's, financial results; however, it will result in additional disclosures.

Comprehensive Income

In June 2011, the FASB issued updated requirements on the presentation of comprehensive income which eliminate the option to present other comprehensive income in the statement of changes in equity. The new requirements will be effective for us as of January 1, 2012. The adoption of this amendment will not have an impact on our, or BGE's financial results, other than the presentation of a separate statement of comprehensive income.

Fair Value Measurements

In May 2011, the FASB issued updated guidance on fair value measurements and disclosure requirements. The update aligns the accounting requirements for fair value measurements under generally accepted accounting principles in the United States and international financial reporting standards. The new requirements will be effective for us as of January 1, 2012. The adoption of this update will not have a material impact on our, or BGE's financial results; however, it will result in additional disclosures.

Accounting Standards Adopted

Accounting for Variable Interest Entities

In June 2009, the FASB amended the accounting, presentation, and disclosure guidance related to variable interest entities.

The amended standard includes the following significant provisions:

- requires an entity to qualitatively assess whether it should consolidate a VIE based on whether the entity (1) has the power to direct matters that most significantly impact the activities of the VIE, and (2) has the obligation to absorb losses or the right to receive benefits of the VIE that could potentially be significant to the VIE,
- requires an ongoing reconsideration of this assessment instead of only upon certain triggering events,
- amends the events that trigger a reassessment of whether an entity is a VIE, and
- requires the entity that consolidates a VIE

  (the primary beneficiary) to present separately on the face of its balance sheet (1) the assets of the consolidated VIE, if they can be used to only settle specific obligations of the consolidated VIE, and (2) the liabilities of a consolidated VIE for which creditors do not have recourse to the general credit of the primary beneficiary.

We adopted this guidance on January 1, 2010 and, as a result of our assessment and implementation of the new requirements, our accounting and disclosures related to VIEs were impacted as follows:

- We have presented separately on our Consolidated Balance Sheets, to the extent material, the assets of our consolidated VIEs that can only be used to settle specific obligations of the consolidated VIE, and the liabilities of our consolidated VIEs for which creditors do not have recourse to our general credit.
- The new requirements emphasize a qualitative assessment of whether the equity holders of the entity have the power to direct matters that most significantly impact the entity. We have evaluated all existing entities under the new VIE accounting requirements, both those previously considered VIEs and those considered potential VIEs. Our accounting for and disclosure about VIEs did not change materially as a result of these assessments.

We discuss our investments in variable interest entities in more detail in *Note 4*.

Noncontrolling Interests in Consolidated Financial Statements

Effective January 1, 2009, we adopted guidance relating to the accounting and reporting of noncontrolling interests in consolidated financial statements. We presented and disclosed our noncontrolling interests in our Consolidated Financial Statements, and we accounted for the 2009 sale of a 49.99% membership interest in CENG to EDF by deconsolidating CENG, measuring our retained interest at fair value, and recognizing a gain at closing. We discuss this transaction in more detail in *Note 2*.

2 Other Events

2011 Events

	Pre-Tax	After-Tax
	(In millions)	
Impairment losses and other costs	$ (891.0)	$ (530.2)
Impact of power purchase agreement with CENG	(200.4)	(118.5)
Amortization of basis difference in CENG	(153.1)	(90.5)
Gain on settlements with U.S. Department of Energy	93.8	57.3
Gain on divestitures	57.3	32.7
Merger costs	(117.9)	(70.9)
Transaction fees for Boston Generating acquisition	(15.5)	(9.9)
Total other items	$ (1,226.8)	$ (730.0)

Impairment Losses and Other Costs

Impairment Evaluations

We discuss our policy for evaluation of assets for impairment and other than temporary declines in value in *Note 1*. We perform impairment evaluations for our long-lived assets, equity method and cost method investments, and goodwill when events occur that indicate that the potential for an impairment exists.

A decrease in long-term forward power prices is a significant event that could result in us performing an impairment evaluation for our generating assets (including those held in equity and cost method investments). One of the primary drivers of forward power prices is forward natural gas prices. A decrease in forward power prices lowers the expected future cash flows from the long-lived asset or equity and cost method investments since sales of power would occur at lower prices and generate lower revenues.

During the fourth quarter of 2011, the following events that lower expected future cash flows resulted in the need for us to perform impairment evaluations of certain of our equity and cost method investments as well as certain of the power plants we own:

- natural gas prices declined approximately 19% during the fourth quarter of 2011 primarily due to an increase in supply, and negatively impacted forward power prices,
- increased uncertainty around the timing and extent of federal carbon legislation also negatively impacted forward power prices,
- changes in the pricing structure for power sales from our power projects and qualifying facilities in California and Utah to reflect lower market-based pricing,
- decreased prices for solar renewable energy credits primarily due to an increase in supply, and
- forecasted additional expenses for a facility in Pennsylvania to comply with the EPA's recent emission regulations.

As a result of these evaluations, we recorded impairments of several of our equity and cost method investments. We describe the impairment evaluations we performed in the following sections.

Equity Method Investments

We evaluated certain of our equity method investments in light of recent declines in commodity prices. The investments we evaluated include our investment in CENG and our investments in certain qualifying facilities.

We record an impairment if an investment has experienced a decline in fair value to a level less than our carrying value and the decline is "other than temporary." We do not record an impairment if the decline in value is temporary and we have the ability to recover the carrying amount of our investment. In making this determination, we evaluate the reasons for an investment's decline in value, the extent and length of that decline, and factors that indicate whether and when the value will recover.

CENG

As of December 31, 2011, the estimated fair value of our investment in CENG was $2.2 billion, which was lower than its carrying value of $3.0 billion.

There is no active market for ownership interests in CENG or comparable entities that solely own and operate nuclear power plants. Therefore, we were required to exercise significant judgment in estimating the fair value of our investment based upon information that a market participant would consider. We believe our estimate incorporates the best data available as of December 31, 2011 for each input, which we describe below. However, the resulting fair value amount remains an estimate and is subject to change in the future based upon changes in any of the inputs or the underlying operating, market, and economic conditions we considered.

Because of the absence of relevant market transactions for similar entities, we estimated the fair value of CENG using discounted future cash flows based upon inputs that we believe reflect a market participant's perspective. Our methodology was consistent with the methodology used to estimate fair value in September 2010, when we previously recorded an impairment of our investment. The most significant inputs to our estimate of fair value include expectations of nuclear plant performance, future power prices, nuclear fuel and operating costs, forecasted capital expenditures, existing power sales commitments and a discounting factor reflective of an investor's required risk-adjusted return. To the extent possible, we considered available market information and other third-party data for each of the inputs. However, because of the long operating lives of nuclear power plants, we were required to estimate inputs for many years beyond periods for which observable market data is available. Additionally, we compared the inputs to relevant historical information, and we benchmarked our valuation using implied market data of other companies that own nuclear generation facilities.

Upon completion of our evaluation, we determined that the fair value of our investment in CENG had declined by approximately $0.8 billion on a pre-tax basis as of December 31, 2011. The decline in fair value is primarily attributable to the following factors:

- significant and sustained declines in forward power and capacity prices that continued into the fourth quarter of 2011,
- continued decreases in the market price of natural gas, particularly in the fourth quarter of 2011, that adversely impact the level of and potential for recovery in power prices in the near term,
- delays in timing and increased uncertainty regarding the timing and provisions of carbon emissions reduction and other potential environmental legislation that reduced estimates of long-term future power prices in the fourth quarter of 2011.

Based upon the extent of the decline below carrying value, the fundamental reasons for and the sustained nature of the decline, and our assessment that a sufficient improvement in these factors necessary to produce a recovery in fair value is not likely to occur in the near term, we determined that the decline in fair value is other than temporary. Therefore, we recorded an $824.2 million pre-tax impairment charge during the quarter ended December 31, 2011 to write-down our investment to fair value as of that date. We recorded this charge in “Impairment losses and other costs” in our Consolidated Statements of Income (Loss). To the extent that the fair value of our investment declines further in future quarters, we may record additional write-downs if we determine that any additional declines are other than temporary.

Qualifying Facilities

As a result of the changes in the pricing structure for qualifying facilities in California and Utah to more of a market based mechanism coupled with the significant decline in forward prices for natural gas in the fourth quarter of 2011, we determined that the fair values of certain of our equity and cost method investments declined substantially below book value. Also, the expected additional cost of complying with the EPA’s recent emission regulations coupled with the decline in natural gas prices in the fourth quarter caused the fair value of one of our waste coal facilities in Pennsylvania to decline substantially below book value. As a result, we recorded a $66.8 million pre-tax impairment charge during the quarter ended December 31, 2011 to write down these investments to fair value as of that date.

We recorded these charges in the “Impairment losses and other costs” line in our Consolidated Statements of Income (Loss).

Generating Plants

We evaluated the impact of the events that occurred during the fourth quarter of 2011 on the recoverability of certain of our wholly owned generating plants. As discussed in *Note 1*, we evaluated whether these plants would generate undiscounted cash flows from operations that are at least sufficient to recover the carrying value of our investment. Based upon our consideration of these events, we determined that our generating plants were not impaired as of December 31, 2011.

Goodwill

We performed our annual impairment review in the quarter ended September 30, 2011 and determined that our goodwill is not impaired. The events of the fourth quarter were not considered triggering events for our goodwill as all of our goodwill is recorded within our retail energy reporting unit within our NewEnergy business segment. For this reporting unit, fair value is primarily impacted by changes in customer margins, which did not materially change in the fourth quarter of 2011.

Impact of Power Purchase Agreement with CENG

In connection with the closing of the CENG membership sale transaction with EDF in 2009, we entered into a five year power purchase agreement (PPA) with CENG with an initial fair value of $0.8 billion.

Based on energy prices at the time of closing of the EDF transaction, we recorded the approximately $0.8 billion “Unamortized energy contract asset” for the value of our PPA with CENG, and CENG recorded an approximately ($0.8) billion “Unamortized energy contract liability.” Both entities are amortizing these amounts over the initial two years of the five-year term of the PPA, with the total net economic value to be realized by us in the form of lower purchased power costs equal to approximately $0.4 billion as a result of our 50.01% ownership interest in CENG. During 2011, we realized approximately $200.4 million pre-tax in economic value relating to its PPA with CENG.

Amortization of Basis Difference in CENG

On November 6, 2009, Constellation Energy sold a 49.99% membership interest in CENG to EDF for total consideration of approximately $4.7 billion (includes $3.5 billion in cash at close, the non-cash redemption of the $1.0 billion Series B Preferred Stock held by EDF, and certain expense reimbursements). As a result, we ceased to have a controlling financial interest in CENG and deconsolidated CENG in the fourth quarter of 2009.

On November 6, 2009, we began to account for our retained investment in CENG using the equity method and report our share of its earnings in our Generation business segment. As a result, we no longer record the individual income statement line items, but instead record our share of the investment’s earnings in a single line in our Consolidated Statements of Income (Loss).

We had an initial basis difference of approximately $3.9 billion between the initial carrying value of our investment in CENG and our underlying equity in CENG. This basis difference was caused by the requirement to record our investment in CENG at fair value at closing while CENG’s assets and liabilities retained their carrying value. We are amortizing this basis difference over the respective useful lives of the assets of CENG or as those assets impact the earnings of CENG.

Beginning in the fourth quarter of 2010, the amortization of the basis difference in CENG is lower as the basis difference was reduced by the amount of the impairment charge recorded on our investment in CENG during the quarter ended September 30, 2010. The new basis difference as of September 30, 2010 was $1.5 billion.

For the year ended December 31, 2011, we recorded $153.1 million of pre-tax basis difference amortization as a reduction to our equity investment earnings in CENG. The impairment recorded in the fourth quarter of 2011 will further reduce the basis difference and, therefore, will reduce future amortization of the basis difference. The basis difference as of December 31, 2011 is $453.1 million. We discuss the components of our equity investment earnings in *Note 4*.

Gain on U.S. Department of Energy Settlements

On June 30, 2011, CENG executed settlement agreements with the United States Department of Energy (DOE) which settled lawsuits involving the Calvert Cliffs nuclear power plant that sought to recover damages caused by the DOE's failure to comply with legal and contractual obligations to dispose of spent nuclear fuel. A similar settlement was reached related to the Ginna nuclear power plant. These agreements detail a framework and procedure for recovery of damages incurred or to be incurred through the end of 2013.

As part of the 2009 agreement between Constellation Energy and EDF that established CENG as a joint venture, Constellation Energy retained the right to receive any such payments for a settlement with the DOE that related to periods prior to the formation of the joint venture on November 6, 2009. Therefore, any funds received from the DOE that represent the settlement of claims incurred through November 6, 2009, the date we sold a 49.99% membership interest in CENG to EDF, will belong to us, and any funds representing the settlement of claims incurred after November 6, 2009 will belong to CENG.

CENG records the receipt of funds from settlements with the DOE as offsets to the accounts where costs were originally charged. For those costs that were originally charged to expense, the offset of those costs will be recognized as part of CENG's earnings, of which Constellation Energy records its 50.01% share.

During 2011, Constellation Energy, through its share of the settlements, recognized the following pre-tax gains as operating income for costs incurred through November 6, 2009 to store spent nuclear fuel:

- $39.4 million related to the Calvert Cliffs nuclear power plant, and
- $54.4 million related to the Ginna nuclear power plant.

The lawsuit relating to the storage of spent nuclear fuel at the Nine Mile Point nuclear power plant remains outstanding.

Gain on Divestitures

Upstream Gas Property

In December 2011, we sold all of our interests in a subsidiary that owned natural gas and oil assets in the south Texas region to Petrohawk Energy Corporation for $93.0 million. Our NewEnergy business recognized a pre-tax gain of $23.0 million on this sale.

We also sold working interests in another natural gas property in the Texas region and recognized a $0.6 million gain.

These gains are recorded on the "Net Gain on Divestiture" line on the Consolidated Statements of Income (Loss).

Constellation Energy Partners LLC

In August 2011, we sold a majority of our interests in Constellation Energy Partners LLC (CEP) to PostRock Energy Corporation (PostRock). Under the terms of the agreement, PostRock received all of our Class A member interests, which includes the right to appoint two of the five members of CEP's board of directors, and approximately 3.1 million units of our Class B member interests. In return, we received $6.6 million in cash, one million shares of PostRock common stock and warrants to acquire an additional 673,822 shares of PostRock common stock. As a result of this August transaction, we recorded a pre-tax gain of $11.4 million in the "Net Gain on Divestitures" line in our Consolidated Statements of Income (Loss).

Immediately following this transaction, we still retained a portion of the voting Class B member interests (approximately 2.8 million units) and other classes of non-voting member interests in CEP. However, since we no longer had significant influence over CEP's activities following the August 2011 sale, our retained interests did not qualify for the equity method of accounting. Upon the cessation of equity method accounting, we reclassified our remaining balance in accumulated other comprehensive income to earnings, recognizing a pre-tax gain of $11.6 million in the "Net Gain on Divestitures" line in our Consolidated Statements of Income (Loss).

In December 2011, we sold all of our remaining Class B member interests in CEP to PostRock for $6 million cash. Upon completion of this transaction, we reclassified into earnings $4.7 million of gain that was previously deferred in 2008 as a result of a sale of upstream assets to CEP from us. As a result of this December transaction, we recorded a pre-tax gain of $10.7 million in the "Net Gain on Divestitures" line in our Consolidated Statements of Income (Loss).

Merger Costs

On April 28, 2011, Constellation Energy entered into an Agreement and Plan of Merger with Exelon Corporation (Exelon). At closing, each issued and outstanding share of common stock of Constellation Energy will be cancelled and converted into the right to receive 0.93 shares of common stock of Exelon, and Constellation Energy will become a wholly owned subsidiary of Exelon. We discuss the terms of the pending merger in more detail in *Note 15*.

During 2011, we incurred $117.9 million pre-tax in costs directly related to our pending merger with Exelon, primarily relating to investment banking fees, legal fees, consulting fees, and employee-related expenses. Of this amount, $30.3 million pre-tax related to BGE. BGE will not seek recovery of these costs in rates.

Transaction Fees for Boston Generating Acquisition

In January 2011, we acquired Boston Generating's 2,950 MW fleet of generating plants for cash of $1.1 billion. We discuss this acquisition in more detail in *Note 15*.

During 2011, we incurred $15.5 million pre-tax in costs related to this acquisition.

2010 Events

	Pre-Tax	After-Tax
	(In millions)	
Impairment losses and other costs	**$(2,476.8)**	**$(1,487.1)**
International coal contract dispute settlement	**56.6**	**35.4**
Deferred income tax expense relating to federal subsidies for providing post-employment prescription drug benefits		**(8.8)**
Amortization of basis difference in CENG	**(195.2)**	**(117.5)**
Loss on early retirement of 2012 Notes	**(51.6)**	**(30.9)**
Impact of power purchase agreement with CENG	**(185.6)**	**(113.3)**
Gain on divestitures	**240.0**	**146.0**
Total other items	**$(2,612.6)**	**$(1,576.2)**

Impairment Losses and Other Costs

Impairment Evaluations

We discuss our policy for evaluation of assets for impairment and other than temporary declines in value in *Note 1*. We perform impairment evaluations for our long-lived assets, equity method and cost method investments, and goodwill when events occur that indicate that the potential for an impairment exists.

During the third quarter of 2010, the following events resulted in the need for us to perform impairment evaluations of our equity method investments as well as the power plants we own:

- commodity prices declined substantially,
- there was a decrease in certainty around the timing and extent of environmental legislation,
- we completed a process that led us to reject the terms and conditions of a Department of Energy (DOE) loan guarantee related to the development of a new nuclear power plant, and
- with respect to our investments in UNE and CENG, certain contractual issues with our partner remained unresolved as of the end of the third quarter of 2010.

As a result of these evaluations, we recorded impairments of several of our equity method investments. We describe the impairment evaluations we performed in the following sections.

<u>Equity Method Investments</u>

We evaluated certain of our equity method investments in light of recent declines in commodity prices and the completion of the process that led to our rejection of the terms and conditions of the DOE loan guarantee for the development of new nuclear assets. The investments we evaluated include our investment in CENG, our investment in UNE, and our investments in certain qualifying facilities.

We record an impairment if an investment has experienced a decline in fair value to a level less than our carrying value and the decline is "other than temporary." We do not record an impairment if the decline in value is temporary and we have the ability to recover the carrying amount of our investment. In making this determination, we evaluate the reasons for an investment's decline in value, the extent and length of that decline, and factors that indicate whether and when the value will recover.

CENG

As of September 30, 2010, the estimated fair value of our investment in CENG was $2.9 billion, which was lower than its carrying value of $5.2 billion. The carrying value of our investment reflected fair value as of the November 9, 2009 closing of EDF's investment in CENG. At that time, we were required to deconsolidate CENG and record our retained investment at fair value.

There is no active market for the ownership interests in CENG or comparable entities that solely own and operate nuclear power plants. Therefore, we were required to exercise significant judgment in estimating the fair value of our investment based upon information that a market participant would consider. We believe our estimate incorporates the best data available as of September 30, 2010 for each input, which we describe below. However, the resulting fair value amount remains an estimate and is subject to change in the future based upon changes in any of the inputs or the underlying operating, market, and economic conditions we considered.

Because of the absence of relevant market transactions for similar entities, we estimated the fair value of CENG using discounted future cash flows based upon inputs that we believe reflect a market participant's perspective. Our methodology was consistent with the methodology used to estimate fair value in November 2009. The most significant inputs to our estimate of fair value include expectations of nuclear plant performance, future power prices, nuclear fuel and operating costs, forecasted capital expenditures, existing power sales commitments and a discounting factor reflective of an investor's required risk-adjusted return. To the extent possible, we considered available market information and other third-party data for each of the inputs. However, because of the long operating lives of nuclear power plants, we were required to estimate inputs for many years beyond periods for which observable market data is available. Additionally, we compared the inputs to relevant historical information, and we benchmarked our valuation using implied market data of other companies that own nuclear generation facilities.

Upon completion of our evaluation, we determined that the fair value of our investment in CENG had declined by approximately $2.3 billion on a pre-tax basis as of September 30, 2010. The decline in fair value is primarily attributable to the following factors:

- significant declines in power prices, particularly in the third quarter of 2010,
- decreases in the market price of natural gas that adversely impact the level of and potential for recovery in power prices in the near term,
- uncertainty regarding the timing and provisions of carbon and other potential environmental legislation negatively impacting estimated future power prices, and
- an increase in the discount rate reflecting higher risk-adjusted required returns for nuclear power plants.

Based upon the extent of the decline below carrying value, the fundamental reasons for the decline, and our assessment that a sufficient improvement in these factors necessary to produce a recovery in fair value is not likely to occur in the near term, we determined that the decline is other than temporary. Therefore, we recorded an approximately $2.3 billion pre-tax impairment charge during the quarter ended September 30, 2010 to write-down our investment to fair value as of that date. We recorded this charge in "Impairment losses and other costs" in our Consolidated Statements of Income (Loss). To the extent that the fair value of our investment declines further in future quarters, we may record additional write-downs if we determine that any additional declines are other than temporary.

UNE

As of September 30, 2010, the estimated fair value of our investment in UNE was zero as compared to its carrying value of $143.4 million.

Prior to the third quarter of 2010, we believed that we would recover our investment in UNE through the development and operation of a new nuclear power plant. However, during the third quarter of 2010, several factors led to a decline in the fair value of our investment, including:

- economics of nuclear baseload generation had deteriorated substantially for reasons described above for CENG, and
- we were unable to negotiate acceptable loan guarantee terms, culminating a process that led us to reject the DOE loan guarantee due to an uneconomic level of costs.

As a result of evaluating these factors, we determined that, as of September 30, 2010, we would not be able to recover the value of our investment. Our determination was based primarily on market-related factors that indicated that a market participant would assign little or no value to this entity due to the absence of a DOE loan guarantee.

We also evaluated whether this decline in fair value was temporary. Based upon the nature of the factors leading to the decline, we determined, at September 30, 2010, that it was unlikely that these matters would be resolved in the near term in a way that would permit recovery in the fair value of our investment. Therefore, we concluded that the decline in the value of our investment in UNE was other than temporary, and we recorded a $143.4 million pre-tax impairment charge during the quarter ended September 30, 2010 to write-down our investment to estimated fair value as of that date. We recorded this charge in "Impairment losses and other costs" in our Consolidated Statements of Income (Loss).

Qualifying Facilities

As a result of the significant declines in power prices during the third quarter of 2010, we determined that the fair values of three of our equity method investments in coal-fired generating plants in California declined substantially below book value. As a result, we recorded a $50.0 million pre-tax impairment charge during the quarter ended September 30, 2010 to write down our investments to fair value as of that date.

Additionally, as a result of a sale of an ownership interest by our partner in the fourth quarter of 2010, we recorded an $8.4 million pre-tax impairment charge on one other equity method investment in California at December 31, 2010. We recorded these charges in the "Impairment losses and other costs" line in our Consolidated Statements of Income (Loss).

Generating Plants

We evaluated the impact of the events that occurred during the third quarter of 2010 on the recoverability of our generating plants. As discussed in *Note 1*, we evaluated whether these plants would generate undiscounted cash flows from operations that are at least sufficient to recover the carrying value of our investment. Based upon our consideration of these events, the primary impact of which is a reduction in power prices, and the status of the generating plants' activities, we determined that our generating plants were not impaired as of September 30, or December 31, 2010.

Goodwill

We performed our annual impairment review in the quarter ended September 30, 2010 and determined that our goodwill is not impaired.

International Coal Contract Dispute Settlement

During 2010, we finalized the settlement of a contract dispute with a third party international coal supplier recognizing net pre-tax earnings of $56.6 million. We divested the majority of our international commodities operations in 2009.

Deferred Income Tax Expense Relating to Federal Subsidies for Providing Post-Employment Prescription Drug Benefits

During March 2010, the Patient Protection and Affordable Care Act and the Healthcare and Education Reconciliation Act of 2010 were signed into law. These laws eliminate the tax exempt status of drug subsidies provided to companies under Medicare Part D after December 31, 2012. As a result of this new legislation, we recorded a noncash charge to reflect additional deferred income tax expense of $8.8 million in March 2010.

Amortization of Basis Difference in CENG

On November 6, 2009, Constellation Energy sold a 49.99% membership interest in CENG to EDF for total consideration of approximately $4.7 billion (includes $3.5 billion in cash at close, the non-cash redemption of the $1.0 billion Series B Preferred Stock held by EDF, and certain expense reimbursements). As a result, we ceased to have a controlling financial interest in CENG and deconsolidated CENG in the fourth quarter of 2009.

On November 6, 2009, we began to account for our retained investment in CENG using the equity method and report our share of its earnings in our Generation business segment. As a result, we no longer record the individual income statement line items, but instead record our share of the investment's earnings in a single line in our Consolidated Statements of Income (Loss).

We had an initial basis difference of approximately $3.9 billion between the initial carrying value of our investment in CENG and our underlying equity in CENG. This basis difference was caused by the requirement to record our investment in CENG at fair value at closing while CENG's assets and liabilities retained their carrying value. We are amortizing this basis difference over the respective useful lives of the assets of CENG or as those assets impact the earnings of CENG.

Beginning in the fourth quarter of 2010, the amortization of the basis difference in CENG was lower as the basis difference was reduced by the amount of the impairment charge recorded on our investment in CENG during the quarter ended September 30, 2010. The new basis difference as of September 30, 2010 was $1.5 billion.

For the year ended December 31, 2010, we recorded $195.2 million of pre-tax basis difference amortization as a reduction to our equity investment earnings in CENG. We discuss the components of our equity investment earnings in *Note 4*.

Loss on Early Retirement of 2012 Notes

In February 2010, we retired an aggregate principal amount of $486.5 million of our 7.00% Notes due April 1, 2012 as part of a cash tender offer, at a premium of approximately 11%. We recognized a pre-tax loss on this transaction of $51.6 million within "Interest Expense" on our Consolidated Statements of Income (Loss).

Impact of Power Purchase Agreement with CENG

In connection with the closing of the CENG membership sale transaction with EDF, we entered into a five year power purchase agreement (PPA) with CENG with an initial fair value of $0.8 billion.

Based on energy prices at the time of closing of the EDF transaction, we recorded the approximately $0.8 billion "Unamortized energy contract asset" for the value of our PPA with CENG, and CENG recorded an approximately ($0.8) billion "Unamortized energy contract liability." Both entities are amortizing these amounts over the initial two years of the five-year term of the PPA, with the total net economic value to be realized by us in the form of lower purchased power costs equal to approximately $0.4 billion as a result of our 50.01% ownership interest in CENG. During 2010, we realized approximately $185.6 million pre-tax in economic value relating to its PPA with CENG.

Divestitures

BGE

In January 2010, BGE completed the sale of its interest in a nonregulated subsidiary that owns a district chilled water facility to a third party. BGE received net cash proceeds of $20.9 million. No gain or loss was recorded on this transaction in 2010. BGE has no further involvement in the activities of this entity.

Mammoth Lakes Geothermal Generating Facility

In August 2010, we completed the sale of our 50% equity interest in the Mammoth Lakes geothermal generating facility in California. We received net cash proceeds of approximately $72.5 million. In the third quarter of 2010, our Generation business recorded a $38.0 million pre-tax gain on this transaction. We have no further involvement in the activities of this generating facility.

Comprehensive Agreement with EDF

In November 2010, we closed on the comprehensive agreement with EDF that restructured the relationship between Constellation Energy and EDF, eliminated the outstanding asset put arrangement, and transferred to EDF the full ownership of UNE. We received approximately $140 million of cash, and $75.2 million of Constellation Energy common stock and recorded a $202.0 million pre-tax gain on this transaction. We discuss the comprehensive agreement with EDF in *Note 4*.

Quail Run Energy Center

In December 2010, we signed an agreement to sell our Quail Run Energy Center, a 550 MW natural gas plant in west Texas, to High Plains Diversified Energy Corporation (HPDEC) for $185.3 million. This agreement was contingent upon HPDEC obtaining financing through the sale of municipal bonds. This agreement was terminated in 2011.

2009 Events

	Pre-Tax	After-Tax
	(In millions)	
Gain on sale of 49.99% membership interest in our nuclear generation and operation business (CENG) to EDF	**$7,445.6**	**$4,456.1**
Amortization of basis difference in CENG	**(29.6)**	**(17.8)**
Net loss on divestitures	**(468.8)**	**(293.2)**
Impairment losses and other costs (1)	**(124.7)**	**(96.2)**
Impairment of nuclear decommissioning trust assets through November 6, 2009	**(62.6)**	**(46.8)**
Loss on redemption of Zero Coupon Senior Notes	**(16.0)**	**(10.0)**
Maryland PSC order—BGE residential customer credits	**(112.4)**	**(67.1)**
Merger termination and strategic alternatives costs	**(145.8)**	**(13.8)**
Workforce reduction costs	**(12.6)**	**(9.3)**
Total other items	**$6,473.1**	**$3,901.9**

(1) After-tax amount net of noncontrolling interest.

Gain on Sale of 49.99% Membership Interest in CENG to EDF

On December 17, 2008, we entered into an Investment Agreement with EDF under which EDF would purchase from us a 49.99% membership interest in CENG for $4.5 billion (subject to certain adjustments).

In October 2009, the Maryland PSC issued an order approving the sale of a 49.99% membership interest in CENG to EDF subject to the following conditions:

- Constellation Energy funded a one-time $100 per customer distribution rate credit for BGE residential customers totaling $112.4 million in the fourth quarter of 2009. Constellation made a $66 million equity contribution to BGE in December 2009 to fund the after-tax amount of the rate credit as ordered by the Maryland PSC.
- Constellation Energy was required to make a $250 million cash capital contribution to BGE by no later than June 30, 2010. Constellation Energy made this contribution in December 2009.
- BGE will not pay common dividends to Constellation Energy if (a) after the dividend payment, BGE's equity ratio would be below 48% as calculated pursuant to the Maryland PSC'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.
- BGE was authorized to file an electric distribution rate case at any time beginning in January 2010 and was ordered not to file a subsequent electric distribution rate case until January 2011. Any rate increase in the first electric distribution rate case was capped at 5% as agreed to by Constellation Energy in its 2008 settlement with the State of Maryland and the Maryland PSC. The timing of any gas distribution rate filing was to occur no earlier than the electric rate case.

- Constellation Energy was limited to allocating no more than 31% of its holding company costs to BGE until the Maryland PSC reviews such cost allocations in the context of BGE's next rate case.
- Constellation Energy and BGE implemented "ring fencing" measures in February 2010 designed to provide bankruptcy protection and credit rating separation of BGE from Constellation Energy. Such measures include the formation of a new special purpose subsidiary by Constellation Energy (RF HoldCo) to hold all of the common equity interests in BGE.

With the receipt of the Maryland PSC's order, Constellation Energy and EDF closed the transaction on November 6, 2009. Upon closing of the transaction, we sold a 49.99% membership interest in CENG to EDF for total consideration of approximately $4.7 billion (includes $3.5 billion in cash at close, the non-cash redemption of the $1.0 billion Series B Preferred Stock held by EDF, and certain expense reimbursements). As a result, we retained a 50.01% economic interest in CENG, but we and EDF have equal voting rights over the activities of CENG. Accordingly, we deconsolidated CENG in the fourth quarter of 2009.

We recorded this transaction as follows:

- We received cash consideration of approximately $3.5 billion, plus certain adjustments, and redeemed the $1.0 billion Series B Preferred Stock held by EDF as additional purchase price resulting in net proceeds of approximately $4.7 billion.
- We removed the individual assets and liabilities of CENG from our balance sheet with a net asset value of approximately $2.4 billion.
- We recorded our retained investment in CENG at estimated fair value of approximately $5.1 billion.
- We recognized a pre-tax gain on sale of approximately $7.4 billion, calculated as follows:

	(In billions)
Fair value of the consideration received from EDF	$ 4.7
Estimated fair value of our retained interest in CENG	5.1
Carrying amount of CENG's assets and liabilities prior to deconsolidation	(2.4)
Pre-tax gain	$ 7.4

On November 6, 2009, we began to account for our retained investment in CENG using the equity method and report our share of its earnings in our Generation business segment. As a result, we no longer record the individual income statement line items, but instead record our share of the investment's earnings in a single line in our Consolidated Statements of Income (Loss).

We estimated the fair value of CENG for purposes of recording our retained interest upon closing of the sale. Our estimate considered the replacement cost, discounted future cash flows, and comparable market transactions valuation approaches. After correlating the valuations under these three approaches, the ultimate fair value estimate reflects the discounted future expected cash flows of the business using various inputs that we believe are reflective of a market participant's perspective. The most significant inputs include our expectations of nuclear plant performance, future power prices, nuclear fuel and operating costs, forecasted capital expenditures, existing power sales commitments, and a discounting factor reflective of an investor's required risk-adjusted return.

The fair value of our investment in CENG exceeded our share of CENG's equity because CENG's assets and liabilities retained their historical carrying value. This basis difference totaled approximately $3.9 billion, and we assigned it to the noncurrent assets of CENG based on fair value. We will amortize this difference as a reduction in our equity investment earnings in CENG as follows:

Difference	Amortization Period
Property, plant and equipment	Depreciable life
Power purchase agreements and revenue sharing agreements	Term of the agreement
Land and intangibles with indefinite lives	Upon sale by CENG

For the period November 6, 2009 through December 31, 2009, we recorded $29.6 million of basis difference amortization as a reduction to our equity investment earnings in CENG. We discuss the components of our equity investment earnings in *Note 4*.

Also, if we were to sell an additional portion of our investment, we would recognize a proportionate amount of the basis difference.

Divestitures

In 2009, we completed many of the strategic initiatives we identified in 2008 to improve liquidity and reduce our business risk.

The transactions to sell a majority of our international commodities, our Houston-based gas trading and other operations were structured in two parts:

- the assignment and transfer of a majority of the portfolio, and
- the execution of a Total Return Swap (TRS) mechanism for the remainder of the portfolio.

Under the TRS, we entered into offsetting trades with the buyers that matched the terms of the remaining third party contracts for which we were unable to complete assignment to the buyers as of the transaction dates. This structure transferred the risks associated with changes in commodity prices as of the transaction dates to the buyers in all instances. However, the trades under the TRS are newly executed transactions, and we remain the principal under both the unassigned third party trades and the matching trades with the buyers under the TRS with no right of either financial or legal offset. We continue to pursue the assignment of these remaining contracts to the buyers.

The matching contracts under the TRS include both derivatives and non-derivatives and were executed at prices that differed from market prices at closing, which resulted in a net cash payment to/from the buyers. We recorded the underlying contracts at fair value on a gross basis as assets or liabilities in our Consolidated Balance Sheets depending on whether the contract prices were above- or below-market prices at closing. As a result, the derivative contracts have been included in “Derivative Assets and Liabilities” and the nonderivative contracts have been included in “Unamortized Energy Contract Assets and Liabilities.” The derivative contracts are subject to mark-to-market accounting until they are realized or assigned. The nonderivative contracts will be amortized into earnings as the underlying contracts are realized, or sooner if those contracts are assigned.

We record the cash proceeds we pay or receive at the inception of energy purchase and sale contracts based upon whether the contracts are in-the-money or out-of-the-money as follows:

In-the-money contracts—proceeds paid	Investing Outflow
Out-of-the-money contracts—proceeds received	Financing Inflow

After inception, we record the cash flows from all energy purchase and sale contracts as operating activities, except for out-of-the-money derivative contracts that were liabilities at inception. We record the ongoing cash flows from these out-of-the-money derivative contracts as financing activities, regardless of whether they are purchase or sale contracts.

International Commodities Operation

In January 2009, we entered into a definitive agreement to sell a majority of our international commodities operation. We completed this transaction on March 23, 2009 and recognized the following impacts during 2009:

- a pre-tax loss of approximately $334.5 million representing net consideration paid to the buyer, the book value of net assets sold, and transaction costs,
- a reclassification of $165.7 million in losses on previously designated cash-flow hedge contracts, for which the forecasted transactions are now deemed probable of not occurring, from “Accumulated Other Comprehensive Loss” to “Nonregulated revenues” in the Consolidated Statements of Income (Loss),
- workforce reduction costs of $10.9 million, recorded as part of “Workforce reduction costs” in the Consolidated Statements of Income (Loss), and
- other costs of $17.6 million related to leasehold improvements, furniture and computer hardware and software, recorded as part of “Impairment losses and other costs” in the Consolidated Statements of Income (Loss).

We removed the contracts that were assigned from our balance sheet, paid the buyer approximately $90 million, and reflected the impact of this payment on our working capital in the operating activities section of our Consolidated Statements of Cash Flows.

The net cash payment to the buyer upon completion of the TRS was $2.5 million. As part of the consideration, we acquired matching nonderivative contracts that resulted in a net liability of approximately $75 million, which will be amortized into earnings as the underlying contracts are realized, or sooner if the original nonderivative contracts are assigned.

We have reflected the contracts under the TRS on a gross basis in cash flows from investing and financing activities in our Consolidated Statements of Cash Flows as follows:

Year Ended December 31, 2009	*(In millions)*
Investing activities—Contract and portfolio acquisitions	**$ (866.3)**
Financing activities—Proceeds from contract and portfolio acquisitions	**863.8**
Net cash flows from contract and portfolio acquisitions	**$ (2.5)**

In addition to the March 23, 2009 transaction for a majority of our international commodities operation, on June 30, 2009 we completed the sale of a uranium market participant that we owned. We received cash proceeds of approximately $43 million and recorded a $27.2 million loss on this sale. This loss from our NewEnergy business segment is included in the "Net (loss) gain on divestitures" line in our Consolidated Statements of Income (Loss).

Houston-Based Gas and Other Trading Operations

On February 3, 2009, we entered into a definitive agreement to sell our Houston-based gas trading operation. We transferred control of this operation on April 1, 2009. In addition, in the second quarter of 2009 we also sold certain other trading operations. In total, we received proceeds of approximately $61 million, and recorded a $102.5 million net loss on these sales in 2009. The net loss on sale primarily relates to nonderivative accrual contracts, which were not recorded on our Consolidated Balance Sheet, the cost associated with disposing of an entire portfolio and not merely individual contracts, and the cost of capital, including contingent capital, to support the operation.

The matching derivative and nonderivative transactions under the TRS discussed above were executed at prices that differed from market prices at closing. As a result, we record the ongoing cash flows related to the out-of-the-money derivative contracts that were liabilities at inception as financing cash flows. This resulted in cash outflows related to financing activities of $858.5 million in our Consolidated Statements of Cash Flows for the year ended December 31, 2009 associated with derivative liabilities that were out-of-the-money.

The net cash receipt from the buyers upon completion of the TRS was $91.9 million in the second quarter of 2009. We have reflected these contracts on a gross basis in cash flows from investing and financing activities in our Consolidated Statements of Cash Flows as follows:

Year Ended December 31, 2009	*(In millions)*
Investing activities—Contract and portfolio acquisitions	**$(1,287.4)**
Financing activities—Proceeds from contract and portfolio acquisitions	**1,379.3**
Net cash flows from contract and portfolio acquisitions	**$ 91.9**

In addition, we incurred other costs of $7.0 million for 2009 related to leasehold improvements, furniture, computer hardware and software costs, which are recorded as part of "Impairment losses and other costs" on our Consolidated Statements of Income (Loss).

On April 1, 2009, we executed an agreement with the buyer of our Houston- based gas trading operation under which the buyer will provide us with the gas supply needed to support our NewEnergy retail gas customer supply activities through March 31, 2011. This agreement was structured such that our requirements to post collateral are reduced. The supplier has liens on the assets of the retail gas supply business as well as our investment in the stock of these entities to secure our obligations under the gas supply agreement. In connection with this agreement, we posted approximately $160 million of collateral. This was subsequently reduced to $100 million. The initial $160 million posted represented approximately 25 percent of the previous collateral requirements to support this operation.

Shipping Joint Venture

We completed the sale of our equity investment in a shipping joint venture during the third quarter of 2009. No gain or loss was recognized on the sale. We discuss the sale of the shipping joint venture below.

Other Nonregulated Divestiture

During the fourth quarter of 2009, one of our nonregulated subsidiaries sold an energy project and recorded a net loss of $4.6 million.

Impairment Losses and Other Costs

We discuss our evaluation of assets for impairment and other than temporary declines in value in *Note 1*. We perform impairment evaluations for our long-lived assets, equity method investments, and goodwill when triggering events occur that indicate the potential for an impairment exists.

Available for Sale Securities

We evaluated certain of our investments in equity securities during 2009. The investments we evaluated included our nuclear decommissioning trust fund assets (through November 6, 2009) and other marketable securities. We record an impairment charge if an investment has experienced a decline in fair value to a level less than our carrying value and the decline is "other than temporary."

In making this determination, we evaluate the reasons for an investment's decline in value, the extent and duration of that decline, and factors that indicate whether and when the value will recover. For securities held in our nuclear decommissioning trust fund for which the market value is below book value, the decline in fair value is considered other than temporary and we write them down to fair value. We discuss our impairment policy in more detail in *Note 1*.

The fair values of certain of the securities held in our nuclear decommissioning trust fund held through November 6, 2009 and other marketable securities declined below book value. As a result, we recorded a $62.6 million pre-tax impairment charge for the year ended December 31, 2009 for our nuclear decommissioning trust fund assets in the "Other income (expense)" line in our Consolidated Statements of Income (Loss). We also recorded an impairment charge of $0.5 million for other marketable securities not included in our nuclear decommissioning trust funds for the year ended December 31, 2009.

The estimates we utilize in evaluating impairment of our available for sale securities require judgment and the evaluation of economic and other factors that are subject to variation, and the impact of such variations could be material.

Equity Method Investments

Shipping Joint Venture

We record an impairment if an equity method investment has experienced a decline in fair value to a level less than our carrying value and the decline is other than temporary. During the quarter ended June 30, 2009, we contemplated several potential courses of action together with our partner relating to the strategic direction of our shipping joint venture and our continuing involvement. This led to a decision to explore a plan to sell our 50% interest to a party related to our joint venture partner for negligible proceeds. We completed the sale of this investment in the third quarter of 2009. We have no further involvement in the activities of the joint venture.

As a result of the events that occurred during the second quarter of 2009, we concluded that the fair value of our investment had declined to a level below the carrying value at June 30, 2009 and that this decline was other than temporary. As such, we recorded a pre-tax impairment charge of $59.0 million associated with our equity investment in our shipping joint venture within the "Impairment losses and other costs" line in our Consolidated Statements of Income (Loss), and reported the charge in our NewEnergy business segment results for 2009.

Constellation Energy Partners LLC

As of March 31, 2009, the fair value of our investment in Constellation Energy Partners LLC (CEP) based upon its closing unit price was $10.0 million, which was lower than its carrying value of $24.0 million.

The decline in fair value of our investment in CEP at that time reflected a number of factors, primarily including difficulties in the financial and credit markets and the decreases in the market price of natural gas and oil.

As a result of evaluating these factors, we determined that the decline in the value of our investment is other than temporary. Therefore, we recorded a $14.0 million pre-tax impairment charge at March 31, 2009 to write-down our investment to fair value. We recorded this charge in "Impairment losses and other costs" in our Consolidated Statements of Income (Loss). We did not record an impairment charge for the remainder of 2009.

District Chilled Water

During 2009, BGE entered into an agreement to sell its interest in a nonregulated subsidiary that owns a district chilled water facility to a third party. We completed this sale in January 2010. We have no further involvement in the activities of this entity.

As a result of these events, we concluded that the fair value of our investment in this subsidiary had declined to a level below carrying value at December 31, 2009 and that this decline was other than temporary. As such, we recorded a pre-tax impairment charge of $12.0 million, net of the noncontrolling interest impact of $8.0 million. The gross impairment charge of $20.0 million is recorded within the "Impairment losses and other costs" line in both our and BGE's Consolidated Statements of Income (Loss). The noncontrolling interest portion of $8.0 million is recorded within the "Net Income Attributable to Noncontrolling Interests and BGE Preference Stock Dividends" line in our Consolidated Statements of Income (Loss) and within the "Net Income Attributable to Noncontrolling Interests" line in BGE's Consolidated Statements of Income.

Other Costs

During 2009, we recorded $31.2 million pre-tax charges in the "Impairment losses and other costs" line in our Consolidated Statements of Income (Loss) primarily related to:

- divested operations—long-lived assets no longer used and lease terminations, and

- the write-off of an uncollectible advance to an affiliate.

Loss on Redemption of Zero Coupon Senior Notes

In November 2009, we redeemed the Zero Coupon Senior Notes early and recognized a pre-tax loss on redemption of $16.0 million within “Interest Expense” on our Consolidated Statements of Income (Loss).

Merger Termination and Strategic Alternatives Costs

We incurred additional costs during 2009 related to the terminated merger agreement with MidAmerican, the transactions related to EDF, and other strategic alternatives costs. These costs totaled $145.8 million pre-tax for the year ended December 31, 2009, and primarily relate to fees incurred to complete the transactions with EDF and the first quarter of 2009 write-off of the unamortized debt discount associated with the 14% Senior Notes (Senior Notes) that were repaid in full to MidAmerican in January 2009. Upon the closing of the transaction with EDF on November 6, 2009, certain of the costs incurred in 2008 and 2009 became tax deductible. We reflected this impact in 2009.

Workforce Reduction Costs

We incurred workforce reduction costs during the fourth quarter of 2008, primarily related to workforce reduction efforts across all of our operations (Q4 2008 Program), and during the first quarter of 2009, primarily related to the divestiture of a majority of our international commodities operation as well as some smaller restructurings elsewhere in our organization (Q1 2009 Program). For the Q1 2009 Program, we recognized a $12.6 million pre-tax charge during 2009 related to the elimination of approximately 180 positions. We substantially completed these workforce reductions during 2010.

The following table summarizes the status of the involuntary severance liabilities at December 31, 2009:

	Q1 2009 Program	Q4 2008 Program
	(In millions)	
Initial severance liability balance	$ 10.8	$ 19.7
Additional expenses recorded in 2009	1.8	—
Amounts recorded as pension and postretirement liabilities	—	(3.0)
Net cash severance liability	12.6	16.7
Cash severance payments	(12.0)	(15.8)
Severance liability balance at December 31, 2009	$ 0.6	$ 0.9

3 Information by Operating Segment

Our reportable operating segments are Generation, NewEnergy, Regulated Electric, and Regulated Gas:

- Our Generation business includes:
  - a power generation and development operation that owns, operates and maintains fossil and renewable generating facilities, a fuel processing facility, qualifying facilities, and power projects in the United States,
  - an operation that manages certain contractually controlled physical assets, including generating facilities, and
  - an interest in a nuclear generation joint venture (CENG) that owns, operates, and maintains five nuclear generating units.
- Our NewEnergy business includes:
  - full requirements load-serving sales of energy and capacity to utilities, cooperatives, and commercial, industrial, and governmental customers,
  - sales of retail energy products and services to residential, commercial, industrial, and governmental customers,
  - structured transactions and risk management services for various customers (including hedging of output from generating facilities and fuel costs) and trading in energy and energy-related commodities to facilitate portfolio management,
  - risk management services for our Generation business,

- design, construction, and operation of renewable energy, heating, cooling, and cogeneration facilities for commercial, industrial, and governmental customers throughout North America, including energy performance contracting and energy efficiency engineering services,
- upstream (exploration and production) natural gas activities, and
- sales of home improvements, servicing of electric and gas appliances, and heating, air conditioning, plumbing, electrical, and indoor air quality systems, and providing electric and natural gas to residential customers in central Maryland.

- Our regulated electric business purchases, transmits, distributes, and sells electricity in central Maryland.
- Our regulated gas business purchases, transports, and sells natural gas in central Maryland.

Our Generation, NewEnergy, Regulated Electric, and Regulated Gas reportable segments are strategic businesses based principally upon regulations, products, and services that require different technologies and marketing strategies. We evaluate the performance of these segments based on net income. We account for intersegment revenues using market prices. A summary of information by operating segment is shown in the table below.

	Reportable Segments				Holding Company and Other	Eliminations	Consolidated
	Generation	NewEnergy	Regulated Electric	Regulated Gas			
				(In millions)			
2011							
Unaffiliated revenues	**$ 1,122.3**	**$ 9,649.0**	**$2,320.7**	**$ 664.5**	**$ 1.7**	**$ —**	**$13,758.2**
Intersegment revenues	**1,595.4**	**471.2**	**0.7**	**7.2**	**—**	**(2,074.5)**	**—**
Total revenues	**2,717.7**	**10,120.2**	**2,321.4**	**671.7**	**1.7**	**(2,074.5)**	**13,758.2**
Depreciation, depletion, accretion, and amortization	**187.4**	**89.4**	**226.5**	**45.6**	**40.4**	**—**	**589.3**
Fixed charges	**128.8**	**9.4**	**103.4**	**23.2**	**0.1**	**0.5**	**265.4**
Income tax (benefit) expense	**(300.7)**	**(8.8)**	**50.1**	**23.4**	**5.1**	**—**	**(230.9)**
Net (loss) income (1)	**(441.1)**	**2.8**	**93.6**	**42.1**	**(4.2)**	**—**	**(306.8)**
Net (loss) income attributable to common stock	**(441.1)**	**(17.5)**	**83.8**	**38.7**	**(4.2)**	**—**	**(340.3)**
Segment assets	**8,738.6**	**4,136.1**	**5,506.7**	**1,480.3**	**854.2**	**(1,303.3)**	**19,412.6**
Capital expenditures	**159.7**	**322.9**	**535.4**	**142.5**	**—**	**—**	**1,160.5**
2010							
Unaffiliated revenues	$ 1,189.2	$ 9,692.6	$2,752.1	$ 704.9	$ 1.2	$ —	$14,340.0
Intersegment revenues	1,055.1	428.8	0.2	4.5	—	(1,488.6)	—
Total revenues	2,244.3	10,121.4	2,752.3	709.4	1.2	(1,488.6)	14,340.0
Depreciation, depletion, accretion, and amortization	137.7	83.7	205.2	44.0	48.9	—	519.5
Fixed charges	142.0	3.0	106.3	24.0	(0.2)	2.7	277.8
Income tax (benefit) expense	(873.1)	106.5	72.6	24.5	3.8	—	(665.7)
Net (loss) income (2)	(1,255.3)	176.2	110.0	37.6	(0.3)	—	(931.8)
Net (loss) income attributable to common stock	(1,255.3)	138.6	99.8	34.6	(0.3)	—	(982.6)
Segment assets	9,789.6	3,836.2	5,287.4	1,379.9	858.0	(1,132.6)	20,018.5
Capital expenditures	327.4	127.2	499.1	103.0	—	—	1,056.7
2009							
Unaffiliated revenues	$ 664.2	$11,345.8	$2,820.7	$ 753.8	$ 14.3	$ —	$15,598.8
Intersegment revenues	2,110.0	163.4	—	4.5	0.1	(2,278.0)	—
Total revenues	2,774.2	11,509.2	2,820.7	758.3	14.4	(2,278.0)	15,598.8
Depreciation, depletion, accretion, and amortization	238.9	82.7	218.1	44.0	67.7	—	651.4
Fixed charges	166.5	39.7	113.3	26.0	2.4	2.2	350.1
Income tax expense (benefit)	3,107.1	(179.1)	50.9	17.1	(9.2)	—	2,986.8
Net income (loss) (3)	4,766.7	(348.2)	79.1	25.5	(19.7)	—	4,503.4
Net income (loss) attributable to common stock	4,766.7	(402.3)	68.9	22.5	(12.4)	—	4,443.4
Segment assets	12,402.1	4,167.5	4,994.6	1,413.4	4,573.7	(4,006.9)	23,544.4
Capital expenditures	1,039.2	116.8	373.0	66.0	—	—	1,595.0

(1) Our Generation business recognized the following after-tax items: impairment losses and other costs of $530.2 million, amortization of the basis difference in CENG of $90.5 million, impact of the power purchase agreement with CENG of $118.5 million, gain on settlements with DOE for storage of spent nuclear fuel of $57.3 million, transaction fees incurred related to our acquisition of Boston Generating's 2,950 MW fleet of generating plants in Massachusetts of $9.9 million, and costs incurred related to our pending merger with Exelon of $37.0 million. Our NewEnergy business recognized a gain on divestitures

of $32.7 million, amortization of credit facility amendment fees in connection with the 2009 EDF transaction of $5.8 million, and costs incurred related to our pending merger with Exelon of $16.1 million. Our Regulated Electric and Gas businesses recognized costs incurred related to our pending merger with Exelon of $13.3 million and $4.5 million, respectively. BGE will not seek recovery of these costs in rates. In addition, our regulated electric business incurred total incremental operating expenses of $24.6 million related to Hurricane Irene.

(2) Our Generation business recognized the following after-tax items: impairment charges on certain of our equity method investment of $1,487.1 million, loss on the early retirement of 2012 Notes of $30.9 million, amortization of the basis difference in CENG of $117.5 million, impact of the power purchase agreement with CENG of $113.3 million, gain on the sale of Mammoth Lakes geothermal generating facility of $24.7 million, and a gain on the comprehensive agreement with EDF of $121.3 million. Our NewEnergy business recognized earnings relating to an international coal supplier contract dispute settlement of $35.4 million. Our Generation, NewEnergy, regulated electric and holding company and other businesses recognized deferred income tax expense relating to federal subsidies for providing post-employment prescription drug benefits of $0.8 million, $0.1 million, $3.1 million, and $4.8 million, respectively. We discuss these items in more detail in Note 2.

(3) Our Generation business recognized the following after-tax items: gain on sale of a 49.99% membership interest in CENG to EDF of $4,456.1 million, amortization of basis difference in investment in CENG of $17.8 million, loss on the early extinguishment of zero coupon senior notes of $10.0 million, merger termination and strategic alternatives costs of $9.7 million, and impairment charges of our nuclear decommissioning trust assets through November 6, 2009 of $46.8 million. Our NewEnergy business recognized the following after-tax items: merger termination and strategic alternatives costs of $4.1 million, losses on divestitures, which include losses on the sales of the international commodities and gas trading operations, the reclassification of losses on previously designated cash-flow hedges from Accumulated Other Comprehensive Loss because the forecasted transactions are probable of not occurring, earnings that are no longer part of our core business, of $371.9 million, impairment losses and other costs of $84.7 million, and workforce reduction costs of $9.3 million. Our regulated electric and gas businesses recognized after-tax charges of $56.7 million and $10.4 million, respectively, for the accrual of a residential customer credit. Our holding company and other businesses recognized after-tax charges of $11.5 million for impairment losses and other costs. We discuss these items in more detail in Note 2.

4 Investments

Investments in Joint Ventures, Qualifying Facilities and Power Projects

Investments in joint ventures, qualifying facilities, and domestic power projects consist of the following:

At December 31,	**2011**	2010
	(In millions)	
CENG Joint Venture	**$2,150.4**	$2,991.1
Qualifying facilities and domestic power projects:		
Coal	**33.4**	65.0
Hydroelectric	**43.0**	46.3
Biomass	**24.6**	55.1
Fuel Processing	**21.4**	16.7
Solar	**—**	6.8
Total	**$2,272.8**	$3,181.0

Investments in joint ventures, qualifying facilities, domestic power projects, and CEP were accounted for under the following methods:

At December 31,	**2011**	2010
	(In millions)	
Equity method	**$2,272.8**	$3,174.2
Cost method	**—**	6.8
Total	**$2,272.8**	$3,181.0

We recorded impairment charges on certain of our equity and cost method investments. We discuss these impairment charges in *Note 2*.

We are actively involved in our CENG nuclear joint venture, qualifying facilities and power projects. Our percentage voting interests in these investments accounted for under the equity method range from 20% to 50.01%. Equity in earnings of these investments is as follows:

Year ended December 31,	**2011**	2010	2009
		(In millions)	
CENG	**$ 148.8**	$ 218.8	$ 33.9
Amortization of basis difference in CENG (see *Note 2* for more detail)	**(153.1)**	(195.2)	(29.6)
Total equity investment earnings—CENG (1)	**(4.3)**	23.6	4.3
UNE	**—**	(16.8)	(24.7)
Shipping JV	**—**	—	(1.8)
CEP	**—**	—	(4.6)
Qualifying facilities and domestic power projects	**24.1**	18.2	20.7
Total equity investment earnings	**$ 19.8**	$ 25.0	$ (6.1)

(1) For the years ended December 31, 2011, 2010, and 2009 total equity investment (losses) earnings in CENG include $1.1 million, $2.0 million, and $0.4 million, respectively, of expense related to the portion of cost of certain share-based awards that we fund on behalf of EDF.

We describe each of these investments below.

Joint Ventures

CENG

On November 6, 2009, we completed the sale of a 49.99% membership interest in CENG, our nuclear generation and operation business, to EDF. As a result of this transaction, we deconsolidated CENG and began to record our 50.01% investment in CENG under the equity method of accounting. Because the transaction occurred on November 6, 2009, we recorded $4.3 million of equity investment earnings in CENG, which represents our share of earnings from CENG from November 6, 2009 through December 31, 2009, net of the amortization of the basis difference in CENG. The basis difference is the difference between the fair value of our investment in CENG at closing and our share of the underlying equity in CENG, because the underlying assets and liabilities of CENG were retained at their carrying value. See *Note 2* for a more detailed discussion.

Summarized balance sheet information for CENG is as follows:

At December 31,	**2011**	2010
	(In millions)	
Current assets	**$ 415.6**	$ 507.4
Noncurrent assets	**4,710.6**	4,583.0
Current liabilities	**273.1**	630.9
Noncurrent liabilities	**1,459.1**	1,338.7

Summarized income statement information for CENG is as follows:

	For the Year Ended December 31, 2011	For the Year Ended December 31, 2010	For the Period from November 6, 2009 through December 31, 2009
		(In millions)	
Revenues	**$ 1,516.3**	$ 1,575.3	$ 217.6
Expenses	**1,248.9**	1,174.5	153.0
Income from operations	**267.4**	400.8	64.6
Net income	**299.8**	441.6	68.5

In future periods, we may be eligible for distributions from CENG in excess of our 50.01% ownership interest based on tax sharing provisions contained in the operating agreement for CENG. We would record these distributions, if realized, in earnings in the period received.

Comprehensive Agreement with EDF

On October 26, 2010, we reached a comprehensive agreement with EDF that restructured the relationship between our two companies, eliminated the outstanding asset put arrangement, and transferred to EDF the full ownership of UNE. This comprehensive agreement was approved by the boards of directors of both Constellation Energy and EDF, and the transaction closed on November 3, 2010. The agreement includes the following significant terms:

- EDF acquired our 50% ownership interest in UNE. Upon completion of this transaction, EDF became the sole owner of UNE, and we no longer have responsibility for developing or financing new nuclear plants through UNE.
- We terminated our rights under the existing asset put arrangement and, as a result, did not sell any of our plants to EDF.

- EDF paid us $140 million in cash and transferred to us 2.4 million of the shares of Constellation Energy common stock that it owned (with a fair value of $72.4 million at the time of the noncash financing transfer).
- EDF relinquished its seat on our Board of Directors, and the existing investor agreement between the companies (which includes a "standstill" provision) was terminated.

Later in November 2010, EDF transferred to us 0.1 million shares of Constellation Energy common stock, with a fair value of $2.8 million, in a noncash financing, upon our registering EDF's remaining shares of Constellation Energy common stock with the Securities and Exchange Commission. This enables EDF to transfer its remaining shares without restriction. We recorded a total pre-tax gain of $202.0 million in the fourth quarter of 2010 related to the above aspects of our comprehensive agreement with EDF.

In addition, upon receipt of necessary approvals:

- CENG will transfer to UNE potential new nuclear sites at the Nine Mile Point and Ginna nuclear generating plants in New York State.
- EDF will transfer to us an additional 1.0 million of the shares of Constellation Energy common stock that it owns.

EDF may release us from our obligation to transfer the potential new nuclear sites and retain the shares if we have not certified to EDF that we have the legal right to transfer the sites by May 2012 or if we do not transfer the sites to UNE by early November 2012.

We and EDF will remain owners in CENG under the same ownership percentages—Constellation Energy holding a 50.01% interest and EDF holding a 49.99% interest. Further:

- The power purchase agreement between CENG and each of Constellation Energy and EDF was modified such that prospective purchases will be unit contingent through the end of its term in 2014. In addition, beginning on January 1, 2015 and continuing to the end of the life of the respective plants, we will purchase 50.01% of the output of CENG's nuclear plants and EDF will purchase 49.99% of that output.
- The administrative services agreement, which specifies payment to us for providing administrative support services to CENG, was extended through 2017.

We discuss the PPA and ASA in more detail in *Note 16*.

<u>UNE</u>

In August 2007, we formed a joint venture, UNE, with EDF to develop, own, and operate new nuclear projects in the United States and Canada. On November 3, 2010, we sold our 50% ownership interest in UNE to EDF. As a result of this transaction, EDF is the sole owner of UNE, and we will no longer have responsibility for developing or financing new nuclear plants through UNE.

Qualifying Facilities and Power Projects

Our Generation business holds up to a 50% voting interest in 15 operating domestic energy projects that consist of electric generation, fuel processing, or fuel handling facilities. Of these 15 projects, 13 are "qualifying facilities" that receive certain exemptions and pricing under the Public Utility Regulatory Policies Act of 1978 based on the facilities' energy source or the use of a cogeneration process.

CEP

In 2011, we sold substantially all of our interests in Constellation Energy Partners LLC (CEP) to PostRock Energy Corporation (PostRock). However, we did retain certain non-voting interests in CEP. Since we no longer have significant influence over CEP's activities following the sale, these retained interests do not qualify for the equity method of accounting. We discuss this transaction in more detail in *Note 2*.

Investments in Variable Interest Entities

As of December 31, 2011, we consolidated four VIEs in which we were the primary beneficiary, and we had significant interests in six other VIEs for which we do not have controlling financial interests and, accordingly, were not the primary beneficiary.

<u>Consolidated Variable Interest Entities</u>

The carrying amounts and classification of the above consolidated VIEs' assets and liabilities included in our consolidated financial statements at December 31, 2011 and 2010 are as follows:

	2011	2010
	(In millions)	
Current assets	**$ 481.5**	$516.6
Noncurrent assets	**348.6**	57.7
Total Assets	**$ 830.1**	$574.3
Current liabilities	**$ 483.4**	$345.5
Noncurrent liabilities	**540.0**	399.0
Total Liabilities	**$ 1,023.4**	$744.5

All of the assets in the table above are restricted for settlement of the VIE obligations and all of the liabilities in the preceding table can only be settled using VIE resources with the exception of $130.0 million of debt relating to a group of solar entities formed by us, which is recourse to us.

RSB BondCo LLC

In 2007, BGE formed RSB BondCo LLC (BondCo), a special purpose bankruptcy-remote limited liability company, to acquire and hold rate stabilization property and to issue and service bonds secured by the rate stabilization property. In June 2007, BondCo purchased rate stabilization property from BGE, including the right to assess, collect, and receive non-bypassable rate stabilization charges payable by all residential electric customers of BGE. These charges are being assessed in order to recover previously incurred power purchase costs that BGE deferred pursuant to Senate Bill 1.

BGE determined that BondCo is a VIE for which it is the primary beneficiary. As a result, BGE, and we, consolidated BondCo.

The BondCo assets are restricted and can only be used to settle the obligations of BondCo. Further, BGE is required to remit all payments it receives from customers for rate stabilization charges to BondCo. During 2011, 2010, and 2009, BGE remitted $92.3 million, $90.3 million, and $85.8 million, respectively, to BondCo.

BGE did not provide any additional financial support to BondCo during 2011 or 2010. Further, BGE does not have any contractual commitments or obligations to provide additional financial support to BondCo unless additional rate stabilization bonds are issued. The BondCo creditors do not have any recourse to the general credit of BGE in the event the rate stabilization charges are not sufficient to cover the bond principal and interest payments of BondCo.

Retail Gas Group

During 2009, our NewEnergy business formed two new entities and combined them with its existing retail gas activities into a retail gas entity group for the purpose of entering into a collateralized gas supply agreement with a third party gas supplier. While we own 100% of these entities, we determined that the retail gas entity group is a VIE because there is not sufficient equity to fund the group’s activities without the additional credit support we provide in the form of a parental guarantee. We are the primary beneficiary of the retail gas entity group; accordingly, we consolidate the retail gas entity group as a VIE, including the existing retail gas customer supply operation, which we formerly consolidated as a voting interest entity.

The gas supply arrangement is collateralized as follows:

- The assets of the retail gas entity group must be used to settle obligations under the third party gas supply agreement before it can make any distributions to us,
- The third party gas supplier has a collateral interest in all of the assets and equity of the retail gas entity group, and
- As of December 31, 2011, we provided a $75 million parental guarantee to the third party gas supplier in support of the retail gas entity group.

Other than credit support provided by the parental guarantee, we do not have any contractual or other obligations to provide additional financial support to the retail gas entity group. The retail gas entity group creditors do not have any recourse to our general credit. Finally, we did not provide any financial support to the retail gas entity group during 2011, other than the equity contributions and parental guarantee.

Retail Power Supply Entity

We also consolidate a retail power supply VIE for which we became the primary beneficiary in 2008 as a result of a modification to its contractual arrangements that changed the allocation of the economic risks and rewards of the VIE among the variable interest holders. The consolidation of this VIE did not have a material impact on our financial results or financial condition.

Solar Project Entity Group

In 2011, we formed a group of solar project limited liability companies to build, own, and operate solar power facilities. While we own 100% of these entities, we determined that the individual solar project entities are VIEs because either the entities require additional subordinated financial support in the form of parental guarantee of debt, loans from the customers in order to obtain the necessary funds for construction of the solar facilities, or the customers absorb price variability from the entities through the fixed price power and/or renewable energy credits purchase agreements. We are the primary beneficiary of the solar project entities because we control the design, construction, and operation of the solar power facilities. We provide capital funding to this solar group for ongoing construction of the solar power facilities as well as a $150 million credit facility.

RF HoldCo LLC

During 2010, as part of the 2009 order from the Maryland PSC approving our transaction with EDF, we created RF HoldCo LLC, a bankruptcy-remote special purpose subsidiary to hold all of the common equity interests in BGE. This subsidiary is not a VIE. However, due to our ownership of 100% of the voting interests of RF HoldCo LLC, we consolidate this subsidiary as a voting interest entity.

BGE and RF HoldCo are separate legal entities and are not liable for the debts of Constellation Energy. Accordingly, creditors of Constellation Energy may not satisfy their debts from the assets of BGE and RF HoldCo except as required by applicable law or regulation. Similarly, Constellation Energy is not liable for the debts of BGE or RF HoldCo. Accordingly, creditors of BGE and RF HoldCo may not satisfy their debts from the assets of Constellation Energy except as required by applicable law or regulation.

Unconsolidated Variable Interest Entities

As of December 31, 2011 and 2010, we had significant interests in six VIEs for which we were not the primary beneficiary. We have not provided any material financial or other support to these entities during 2011 and 2010 and we do not intend to provide any additional financial or other support to these entities in the future.

The following is summary information available as of December 31, 2011 about these entities:

	Power Contract Monetization VIEs	All Other Power Project VIEs	Total
		(In millions)	
Total assets	$ 386.5	$309.6	$696.1
Total liabilities	303.9	106.4	410.3
Our ownership interest	—	53.5	53.5
Other ownership interests	82.6	149.7	232.3
Our maximum exposure to loss:			
Letters of credit	15.5	—	15.5
Carrying amount of our investment—Other investments	—	39.8	39.8
Debt and payment guarantees	—	5.0	5.0

The following is summary information available as of December 31, 2010 about these entities:

	Power Contract Monetization VIEs	All Other VIEs	Total
		(In millions)	
Total assets	$ 492.9	$288.3	$781.2
Total liabilities	382.6	113.2	495.8
Our ownership interest	—	48.7	48.7
Other ownership interests	110.3	126.4	236.7
Our maximum exposure to loss:			
Letters of credit	24.9	—	24.9
Carrying amount of our investment—Other investments	—	41.4	41.4
Debt and payment guarantees	—	5.0	5.0

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

Power Contract Monetization VIEs

In March 2005, our NewEnergy business closed a transaction in which we assumed from a counterparty two power sales contracts with previously existing VIEs. The VIEs previously were created by the counterparty to issue debt in order to monetize the value of the original contracts to purchase and sell power. Under the power sales contracts, we sell power to the VIEs which, in turn, sell that power to an electric distribution utility through 2013. In connection with this transaction, a third party acquired the equity of the VIEs and we loaned that party a portion of the purchase price. If the electric distribution utility were to default under its obligation to buy power from the VIEs, the equity holder could transfer its equity interests to us in lieu of repaying the loan. In this event, we would have the right to seek recovery of our losses from the electric distribution utility.

5 Intangible Assets

Goodwill

Goodwill is the excess of the cost of an acquisition over the fair value of the net assets acquired. As of December 31, 2011 and 2010, our goodwill balance was primarily related to our retail energy reporting unit within our NewEnergy business segment. Goodwill is not amortized; rather, it is evaluated for impairment at least annually.

The changes in the gross amount of goodwill and the accumulated impairment losses for the years ended December 31, 2011 and 2010 are as follows:

At December 31,	**2011**	2010
	(In millions)	
Balance as of January 1,		
Gross goodwill	**$ 343.5**	$ 292.0
Accumulated impairment losses	**(266.5)**	(266.5)
Net goodwill	**77.0**	25.5
Goodwill acquired (1)	**202.4**	51.5
Impairment losses	**—**	—
Other purchase price adjustments	**2.8**	—
Balance as of December 31,		
Gross goodwill	**548.7**	343.5
Accumulated impairment losses	**(266.5)**	(266.5)
Net goodwill	**$ 282.2**	$ 77.0

(1) *We discuss the goodwill acquired in 2011 and 2010 in more detail in Note 15.*

For tax purposes, $154.0 million of our gross goodwill balance at December 31, 2011 is deductible.

Intangible Assets Subject to Amortization

Intangible assets with finite lives are subject to amortization over their estimated useful lives. The primary assets included in this category are as follows:

At December 31,	**2011**			2010		
	Gross Carrying Amount	**Accumulated Amortization**	**Net Asset**	Gross Carrying Amount	Accumulated Amortization	Net Asset
			(In millions)			
Software	**$ 478.6**	**$ (322.7)**	**$155.9**	$596.8	$(397.1)	$199.7
Permits and licenses	**4.5**	**(1.6)**	**2.9**	2.7	(1.0)	1.7
Other	**233.3**	**(89.6)**	**143.7**	22.3	(8.2)	14.1
Total	**$ 716.4**	**$ (413.9)**	**$302.5**	$621.8	$(406.3)	$215.5

BGE had intangible assets with a gross carrying amount of $140.2 million and accumulated amortization of $76.8 million at December 31, 2011 and $250.2 million and accumulated amortization of $171.4 million at December 31, 2010 that are included in the table above. Substantially all of BGE's intangible assets relate to software.

We recognized amortization expense related to our intangible assets as follows:

Year Ended December 31,	**2011**	2010	2009
		(In millions)	
Nonregulated businesses	**$ 87.8**	$64.8	$74.2
BGE	**25.4**	25.8	23.6
Total Constellation Energy	**$113.2**	$90.6	$97.8

The following is our, and BGE's, estimated amortization expense related to our intangible assets for 2012 through 2016 for the intangible assets included in our, and BGE's, Consolidated Balance Sheets at December 31, 2011:

Year Ended December 31,	2012	2013	2014	2015	2016
			(In millions)		
Estimated amortization expense—Nonregulated businesses	$ 82.8	$62.1	$40.9	$22.4	$14.0
Estimated amortization expense—BGE	20.7	16.3	10.3	6.9	1.7
Total estimated amortization expense—Constellation Energy	$103.5	$78.4	$51.2	$29.3	$15.7

Unamortized Energy Contracts

As discussed in *Note 1*, unamortized energy contract assets and liabilities represent the remaining unamortized balance of nonderivative energy contracts acquired, certain contracts which no longer qualify as derivatives due to the absence of a liquid market, or derivatives designated as normal purchases and normal sales, which we previously recorded as derivative assets and liabilities. Unamortized energy contract assets also include the power purchase agreement entered into with CENG with an initial fair value of approximately $0.8 billion. See *Note 16* for more details on this power purchase agreement.

We present separately in our Consolidated Balance Sheets the net unamortized energy contract assets and liabilities for these contracts. The table below presents the gross and net carrying amount and accumulated amortization of the net liability that we have recorded in our Consolidated Balance Sheets:

At December 31	**2011**			2010		
	Carrying Amount	**Accumul-ated Amortiz-ation**	**Net (Liability) Asset**	Carrying Amount	Accumul-ated Amortiz-ation	Net Asset
	(In millions)					
Unamortized energy contracts, net	**$(1,454.9)**	**$1,152.5**	**$ (302.4)**	$(1,360.9)	$1,473.8	$112.9

We recognized amortization expense (income) of $395.4 million, $106.8 million, and ($353.1) million related to these energy contract assets for the years ended December 31, 2011, 2010, and 2009 for our nonregulated businesses.

The table below presents the estimated amortization for these assets and liabilities over the next five-years:

Year Ended December 31,	2012	2013	2014	2015	2016
			(In millions)		
Estimated amortization expense (income)	$(65.2)	$(81.2)	$(71.3)	$(65.6)	$(16.4)

6 Regulatory Assets (net)

As discussed in *Note 1*, the Maryland PSC and the FERC provide the final determination of the rates we charge our customers for our regulated businesses. Generally, we use the same accounting policies and practices used by nonregulated companies for financial reporting under accounting principles generally accepted in the United States of America. However, sometimes the Maryland PSC or FERC orders an accounting treatment different from that used by nonregulated companies to determine the rates we charge our customers. When this happens, we must defer certain regulated expenses and income in our Consolidated Balance Sheets as regulatory assets and liabilities. We then record them in our Consolidated Statements of Income (Loss) (using amortization) when we include them in the rates we charge our customers.

We summarize regulatory assets and liabilities in the following table, and we discuss each of them separately below.

At December 31,	**2011**	2010
	(In millions)	
Deferred fuel costs		
Rate stabilization deferral	**$ 358.3**	$ 415.6
Other	**61.0**	8.8
Electric generation-related regulatory asset	**71.4**	86.9
Net cost of removal	**(218.2)**	(210.5)
Income taxes recoverable through future rates (net)	**71.4**	68.3
Deferred BGE Smart Energy Savers Program® costs	**123.5**	64.3
Deferred Advanced Meter Infrastructure costs	**15.4**	12.2
Deferred storm costs	**12.4**	—
Deferred postretirement and postemployment benefit costs	**5.2**	6.4
Deferred environmental costs	**3.1**	5.6
Workforce reduction costs	**1.1**	1.3
Other (net)	**(9.0)**	(6.1)
Total regulatory assets (net)	**495.6**	452.8
Less: Current portion of regulatory assets (net)	**153.7**	78.7
Long-term portion of regulatory assets (net)	**$ 341.9**	$ 374.1

Deferred Fuel Costs

Rate Stabilization Deferral

In June 2006, Senate Bill 1 was enacted in Maryland and imposed a rate stabilization measure that capped rate increases by BGE for residential electric customers at 15% from July 1, 2006 to May 31, 2007. As a result, BGE recorded a regulatory asset on its

Consolidated Balance Sheets equal to the difference between the costs to purchase power and the revenues collected from customers, as well as related carrying charges based on short-term interest rates from July 1, 2006 to May 31, 2007. In addition, as required by Senate Bill 1, the Maryland PSC approved a plan that allowed residential electric customers the option to further defer the transition to market rates from June 1, 2007 to January 1, 2008. During 2007, BGE deferred $306.4 million of electricity purchased for resale expenses and certain applicable carrying charges as a regulatory asset related to the rate stabilization plans. During 2011 and 2010, BGE recovered $57.2 million and $61.8 million, respectively, of electricity purchased for resale expenses and carrying charges related to the rate stabilization plan regulatory asset. BGE began amortizing the regulatory asset associated with the deferral which ended in May 2007 to earnings over a period not to exceed ten years when collection from customers began in June 2007. Customers who participated in the deferral from June 1, 2007 to December 31, 2007 repaid the deferred charges without interest over a 21-month period which began in April 2008 and ended in December 2009.

Other

As described in *Note 1*, deferred fuel costs are the difference between our actual costs of purchased energy and our fuel rate revenues collected from customers. We reduce deferred fuel costs as we collect them from our customers.

We exclude other deferred fuel costs from rate base because their existence is relatively short-lived. These costs are recovered in the following year through our fuel rates.

Electric Generation-Related Regulatory Asset

As a result of the deregulation of electric generation, BGE ceased to meet the requirements for accounting for a regulated business for the previous electric generation portion of its business. As a result, BGE wrote-off its entire individual, generation-related regulatory assets and liabilities. BGE established a single, generation-related regulatory asset to be collected through its regulated rates, which is being amortized on a basis that approximates the pre-existing individual regulatory asset amortization schedules.

A portion of this regulatory asset represents income taxes recoverable through future rates that do not earn a regulated rate of return. These amounts were $56.0 million as of December 31, 2011 and $53.3 million as of December 31, 2010. We will continue to amortize this amount through 2017.

Net Cost of Removal

As discussed in *Note 1*, we use the group depreciation method for the regulated business. This method is currently an acceptable method of accounting under accounting principles generally accepted in the United States of America and has been widely used in the energy, transportation, and telecommunication industries.

Historically, under the group depreciation method, the anticipated costs of removing assets upon retirement were provided for over the life of those assets as a component of depreciation expense. However, effective January 1, 2003, the recognition of expected net future costs of removal is shown as a component of depreciation expense or accumulated depreciation.

BGE is required by the Maryland PSC to use the group depreciation method, including cost of removal, under regulatory accounting. For ratemaking purposes, net cost of removal is a component of depreciation expense and the related accumulated depreciation balance is included as a net reduction to BGE's rate base investment. For financial reporting purposes, BGE continues to accrue for the future cost of removal for its regulated gas and electric assets by increasing a regulatory liability. This liability is relieved when actual removal costs are incurred.

Income Taxes Recoverable Through Future Rates (net)

As described in *Note 1*, income taxes recoverable through future rates are the portion of our net deferred income tax liability that is applicable to our regulated business, but has not been reflected in the rates we charge our customers. These income taxes represent the tax effect of temporary differences in depreciation and the allowance for equity funds used during construction, offset by differences in deferred tax rates and deferred taxes on deferred investment tax credits. We amortize these amounts as the temporary differences reverse.

Deferred BGE Smart Energy Savers Program® Costs

Deferred BGE Smart Energy Savers Program® costs are the costs incurred to implement demand response and conservation programs. These programs are designed to help BGE manage peak demand, improve system reliability, reduce customer consumption, and improve service to customers by giving customers greater control over their energy use. Actual marketing and customer bonus costs incurred in the demand response program, which began in January 2008, are being recovered over a 5-year amortization period from the date incurred pursuant to an order by the Maryland PSC. Fixed assets are recovered over the life of the equipment. Actual costs incurred in the conservation program are being amortized over a 5-year period with recovery beginning in 2010 pursuant to an order by the Maryland PSC.

Deferred Advanced Meter Infrastructure Costs

Between 2007 and 2009, the Maryland PSC approved and BGE conducted a series of successful smart grid pilot programs for a total cost of $11.3 million, which, pursuant to a Maryland PSC order, was deferred in a regulatory asset, and, beginning with the Maryland PSC's March 2011 rate order, is earning a regulated rate of return. In August 2010, the Maryland PSC approved a comprehensive smart grid initiative for BGE that included the planned installation of 2 million residential and commercial electric and gas smart meters and modules. As part of the Maryland PSC's August 2010 order, BGE has been authorized to establish a separate regulatory asset for incremental costs incurred to implement the initiative, net depreciation and amortization associated with the meters, and an appropriate return on these costs. Additionally, the Maryland PSC order requires that BGE prove the cost-effectiveness of the entire smart grid initiative prior to seeking recovery of the costs deferred in these regulatory assets. Therefore, the commencement and timing of the amortization of these deferred costs is currently unknown.

Deferred Storm Costs

In the Maryland PSC's March 2011 rate order, BGE was authorized to defer as a regulatory asset $15.8 million in storm costs incurred in February 2010. These costs are being amortized over a 5-year period that began in December 2010.

Deferred Postretirement and Postemployment Benefit Costs

We record a regulatory asset for the deferred postretirement and postemployment benefit costs in excess of the costs we included in the rates we charged our customers through 1997. We began amortizing these costs over a 15-year period in 1998.

Deferred Environmental Costs

Deferred environmental costs are the estimated costs of investigating and cleaning up contaminated sites we own. We discuss this further in *Note 12*. We amortized $21.6 million of these costs (the amount we had incurred through October 1995) and $6.4 million of these costs (the amount we incurred from November 1995 through June 2000) over 10-year periods in accordance with the Maryland PSC's orders. We received rate relief for an additional $5.4 million of clean-up costs incurred during the period from July 2000 through November 2005 and an additional $1.0 million from December 2005 through November 2010. These costs are being amortized over a 10-year periods that began in January 2006 and December 2010, respectively.

Workforce Reduction Costs

The portion of the costs associated with our 2008 workforce reduction program that relate to BGE's gas business were deferred in 2009 as a regulatory asset in accordance with the Maryland PSC's orders in prior rate cases and are being amortized over a 5-year period that began in January 2009. Costs associated with a 2010 workforce reduction were deferred as a regulatory asset and are being amortized over a 5-year period that began in March 2011 in accordance with the Maryland PSC's March 2011 rate order.

Other (Net)

Other regulatory assets are comprised of a variety of current assets and liabilities that primarily do not earn a regulatory rate of return due to their short-term nature.

7 Pension, Postretirement, Other Postemployment, and Employee Savings Plan Benefits

We offer pension, postretirement, other postemployment, and employee savings plan benefits. BGE employees participate in the benefit plans that we offer. We describe each of our plans separately below. Nine Mile Point, owned by CENG, offers its own pension, postretirement, other postemployment, and employee savings plan benefits to its employees. In connection with the deconsolidation of CENG as a result of the investment in CENG by EDF on November 6, 2009, the Nine Mile Point plan is no longer included in our consolidated results. In addition, benefit plan assets and obligations relating to CENG employees that previously participated in our plans were transferred into new CENG plans that are no longer included in our consolidated results. Therefore, the tables below include the benefits for the CENG plans, including Nine Mile Point, through November 6, 2009. In 2011, we acquired certain Boston Generating plants. As a result, the benefit plan assets and obligations relating to Boston Generating employees are included in our consolidated results and included in the tables below.

We use a December 31 measurement date for our pension, postretirement, other postemployment, and employee savings plans. The following table summarizes our defined benefit liabilities and their classification in our Consolidated Balance Sheets:

At December 31,	**2011**	2010
	(In millions)	
Pension benefits	**$327.8**	$218.0
Postretirement benefits	**347.8**	334.9
Postemployment benefits	**53.1**	55.0
Total defined benefit obligations	**728.7**	607.9
Less: Amount recorded in other current liabilities	**30.7**	33.2
Total noncurrent defined benefit obligations	**$698.0**	$574.7

Pension Benefits

We sponsor several defined benefit pension plans for our employees. These include basic qualified plans that most employees participate in and several non-qualified plans that are available only to certain employees. A defined benefit plan specifies the amount of benefits a plan participant is to receive using information about the participant. Employees do not contribute to these plans. Generally, we calculate the benefits under these plans based on age, years of service, and pay.

Sometimes we amend the plans retroactively. These retroactive plan amendments require us to recalculate benefits related to participants' past service. We amortize the change in the benefit costs from these plan amendments on a straight-line basis over the average remaining service period of active employees.

We fund the qualified plan by contributing at least the minimum amount required under IRS regulations. We calculate the amount of funding using an actuarial method called the traditional unit credit method.

Postretirement Benefits

We sponsor defined benefit postretirement health care and life insurance plans that cover the majority of our employees. Generally, we calculate the benefits under these plans based on age, years of service, and pension benefit levels or final base pay. We do not fund these plans. For nearly all of the health care plans, retirees make contributions to cover a portion of the plan costs. For the life insurance plan, retirees do not make contributions to cover a portion of the plan costs.

Effective in 2002, we amended our postretirement medical plans for all subsidiaries other than Nine Mile Point. Our contributions for retiree medical coverage for future retirees who were under the age of 55 on January 1, 2002 are capped at the 2002 level. We also amended our plans to increase the Medicare eligible retirees' share of medical costs.

In 2003, the President signed into law the Medicare Prescription Drug Improvement and Modernization Act of 2003 (the Act). This legislation provides a prescription drug benefit for Medicare beneficiaries, a benefit that we provide to our Medicare eligible retirees. Our actuaries concluded that prescription drug benefits available under our postretirement medical plan are "actuarially equivalent" to Medicare Part D and thus qualify for the subsidy under the Act. This subsidy reduced our 2011 Accumulated Postretirement Benefit Obligation by $30.3 million and our 2011 postretirement medical payments by $3.1 million.

Liability Adjustments

At December 31, 2011 and 2010, our pension obligations and the fair value of our plan assets for our qualified and our nonqualified pension plans were as follows:

	Qualified Plans			
At December 31, 2011	Constellation Energy	Boston Generating	Non-Qualified Plans	Total
Accumulated benefit obligation	**$ 1,567.0**	**$ 3.2**	**$ 101.8**	**$1,672.0**
Fair value of assets	**1,484.3**	**3.4**	**—**	**1,487.7**
Net (asset) unfunded obligation	**$ 82.7**	**$ (0.2)**	**$ 101.8**	**$ 184.3**

At December 31, 2010	Qualified Plan	Non-Qualified Plans	Total
		(In millions)	
Accumulated benefit obligation	**$1,405.2**	**$ 87.8**	**$1,493.0**
Fair value of assets	**1,408.1**	**—**	**1,408.1**
Net (asset) unfunded obligation	**$ (2.9)**	**$ 87.8**	**$ 84.9**

We are required to reflect the funded status of our pension plans in terms of the projected benefit obligation, which is higher than the accumulated benefit obligation because it includes the impact of expected future compensation increases on the pension obligation. We reflect the funded status of our postretirement benefits in terms of the accumulated postretirement benefit obligation.

The following table summarizes the impacts of funded status adjustments recorded during 2011 and 2010:

			Accumulated Other Comprehensive Income (Loss)	
	Pension Liability	Postretirement Benefit Liability	Pre-tax	After-tax
		(In millions)		
December 31, 2011	**$167.2**	**$ 8.0**	**$(175.2)**	**$(106.4)**
December 31, 2010	$ 73.7	$ 10.9	$ (84.6)	$ (54.6)

Obligations and Assets

We show the change in the benefit obligations and plan assets of the pension and postretirement benefit plans in the following tables. Postretirement benefit plan amounts are presented net of expected reimbursements under Medicare Part D.

	Pension Benefits		Postretirement Benefits	
	2011	2010	**2011**	2010
	(In millions)			
Change in benefit obligation (1)				
Benefit obligation at January 1	**$1,626.1**	$1,469.8	**$334.9**	$322.3
Service cost	**50.3**	37.9	**2.9**	2.4
Interest cost	**87.4**	84.7	**17.1**	17.7
Plan amendments	**(0.5)**	—	**1.3**	(3.3)
Plan participants' contributions	**—**	—	**9.7**	10.5
Actuarial loss	**146.2**	124.0	**6.7**	14.2
Acquisition of Boston Generating plan	**3.2**	—	**—**	—
Separation of CENG plans	**—**	(3.0)	**—**	—
Settlements	**(6.0)**	(5.2)	**—**	—
Special termination benefits	**—**	0.6	**0.2**	0.1
Benefits paid (2)(3)	**(91.2)**	(82.7)	**(25.0)**	(29.0)
Benefit obligation at December 31	**$1,815.5**	$1,626.1	**$347.8**	$334.9

(1) Amounts reflect projected benefit obligation for pension benefits and accumulated postretirement benefit obligation for postretirement benefits.
(2) Pension benefits paid include annuity payments and lump-sum distributions.
(3) Postretirement benefits paid are net of Medicare Part D and Early Retiree Reimbursement Program reimbursements.

	Pension Benefits		Postretirement Benefits	
	2011	2010	**2011**	2010
	(In millions)			
Change in plan assets				
Fair value of plan assets at January 1	**$1,408.1**	$1,058.1	**$ —**	**$ —**
Actual return on plan assets	**89.5**	148.8	**—**	**—**
Employer contribution (1)	**84.3**	289.1	**15.3**	**18.5**
Plan participants' contributions	**—**	—	**9.7**	**10.5**
Acquisition of Boston Generating Plan	**3.0**	—	**—**	**—**
Settlements	**(6.0)**	(5.2)	**—**	**—**
Benefits paid (2)(3)	**(91.2)**	(82.7)	**(25.0)**	**(29.0)**
Fair value of plan assets at December 31	**$1,487.7**	$1,408.1	**$ —**	**$ —**

(1) Includes benefit payments for unfunded plans.
(2) Pension benefits paid include annuity payments and lump-sum distributions.
(3) Postretirement benefits paid are net of Medicare Part D and Early Retiree Reimbursement Program reimbursements.

Net Periodic Benefit Cost and Amounts Recognized in Other Comprehensive Income

We show the components of net periodic pension benefit cost in the following table:

Year Ended December 31,	**2011**	2010	2009
	(In millions)		
Components of net periodic pension benefit cost			
Service cost	**$ 50.3**	$ 37.9	$ 50.8
Interest cost	**87.4**	84.7	101.1
Expected return on plan assets	**(114.9)**	(101.8)	(118.9)
Amortization of unrecognized prior service cost	**3.9**	3.9	10.9
Recognized net actuarial loss	**44.6**	34.4	38.3
Amount capitalized as construction cost	**(10.6)**	(10.2)	(10.2)
Net periodic pension benefit cost (1)	**$ 60.7**	$ 48.9	$ 72.0

(1) Net periodic pension benefit cost excludes settlement charges of $4.0 million and termination benefits of $0.2 million in 2011, settlement charge of $1.5 million and termination benefits of $0.6 million in 2010, and a settlement charge of $9.0 million and a termination benefit of $0.1 million in 2009. BGE's portion of our net periodic pension benefit costs, excluding amount capitalized, was $34.0 million in 2011, $30.9 million in 2010, and $27.9 million in 2009. The vast majority of our retirees were BGE employees.

We show the components of net periodic postretirement benefit cost in the following table:

Year Ended December 31,	2011	2010	2009
		(In millions)	
Components of net periodic postretirement benefit cost			
Service cost	**$ 2.9**	$ 2.4	$ 6.3
Interest cost	**17.1**	17.7	22.6
Amortization of transition obligation	**1.7**	2.1	2.1
Recognized net actuarial loss	**1.5**	0.4	2.2
Amortization of unrecognized prior service cost	**(2.7)**	(2.6)	(3.4)
Amount capitalized as construction cost	**(5.3)**	(5.4)	(6.3)
Net periodic postretirement benefit cost (1)	**$15.2**	$14.6	$23.5

(1) *Net periodic postretirement benefit cost excludes termination benefits of $0.1 million in 2010. BGE's portion of our net periodic postretirement benefit cost, excluding amounts capitalized, was $17.5 million in 2011, $17.2 million in 2010, and $18.7 million in 2009.*

In determining net periodic pension benefit cost, we apply our expected return on plan assets to a market-related value of plan assets that recognizes asset gains and losses ratably over a five-year period.

The following is a summary of amounts we have recorded in "Accumulated other comprehensive loss" and of expected amortization of those amounts over the next twelve months:

	Pension Benefits		Postretirement Benefits		
	2011	2010	2011	2010	Expected Amortiz-ation Next 12 Months
			(In millions)		
Unrecognized actuarial loss	**$864.6**	$741.4	**$ 70.5**	$ 65.3	**$ 60.1**
Unrecognized prior service cost	**1.9**	6.1	**(10.0)**	(14.0)	**(0.5)**
Unrecognized transition obligation	**—**	—	**1.8**	3.5	**1.8**
Total	**$866.5**	$747.5	**$ 62.3**	$ 54.8	**$ 61.4**

Expected Cash Benefit Payments

The pension and postretirement benefits we expect to pay in each of the next five calendar years and in the aggregate for the subsequent five years are shown in the following table. These estimated benefits are based on the same assumptions used to measure the benefit obligation at December 31, 2011, but include benefits attributable to estimated future employee service.

	Pension Benefits	Postretirement Benefits (1)
2012	$109.2	$ 22.4
2013	107.6	23.0
2014	114.2	23.5
2015	165.7	23.9
2016	129.9	24.3
2017-2021	715.0	123.4

(1) *Postretirement benefit payments are net of Medicare Part D reimbursements.*

Assumptions

We made the assumptions below to calculate our pension and postretirement benefit obligations and periodic cost.

	Pension Benefits (1)		Postretirement Benefits		
	2011	2010	2011	2010	Assumption Impacts Calculation of
Discount rate as of January 1	**5.50%**	6.00%	**5.50%**	6.00%	Periodic Cost
Discount rate as of December 31	**4.75%**	5.50%	**4.75%**	5.50%	Benefit Obligation
Expected return on plan assets	**8.00**	8.50	**N/A**	N/A	Periodic Cost
Rate of compensation increase	**4.0**	4.0	**4.0**	4.0	Benefit Obligation and Periodic Cost

(1) The Boston Generating Plan made the following assumptions to calculate its pension benefit obligation and periodic cost: discount rate as of January 3, 2011, the date of acquisition, 5.10%, discount rate as of December 31, 2011 4.20%, expected return on plan assets 8.00%, and rate of compensation increase 4.0%.

Our discount rate is based on a bond portfolio analysis of high quality corporate bonds whose maturities match our expected benefit payments. Our 8.00% overall expected long-term rate of return on plan assets reflected our long-term investment strategy in terms of asset mix and expected returns for each asset class at the beginning of 2011. Effective in 2012, we reduced our expected long-term rate of return assumption to 7.50% reflecting our updated investment strategy, asset mix, and expected return for each asset class.

Annual health care inflation rate assumptions also impact the calculation of our postretirement benefit obligation and periodic cost. We assumed the following health care inflation rates to produce average claims by year as shown below:

At December 31,	**2011**	2010
Next year	**7.5%**	8.5%
Following year	**7.0%**	7.5%
Ultimate trend rate	**5.0%**	5.0%
Year ultimate trend rate reached	**2017**	2017

A one-percentage point increase in the health care inflation rate from the assumed rates would increase the accumulated postretirement benefit obligation by approximately $22.1 million as of December 31, 2011 and would increase the combined service and interest costs of the postretirement benefit cost by approximately $1.3 million annually.

A one-percentage point decrease in the health care inflation rate from the assumed rates would decrease the accumulated postretirement benefit obligation by approximately $19.1 million as of December 31, 2011 and would decrease the combined service and interest costs of the postretirement benefit cost by approximately $1.1 million annually.

Qualified Pension Plan Assets

Investment Strategy

We invest our qualified pension plan assets using the following investment objectives:

- ensure availability of funds for payment of plan benefits as they become due,
- provide for a reasonable amount of long-term growth of capital (both principal and income) without excessive volatility,
- produce investment results that meet or exceed the assumed long-term rate of return,
- improve the funded status of the plan over time, and
- reduce future contribution and expense volatility as funded status improves.

To achieve these objectives, Constellation Energy, through a management Investment Committee (the Committee), which includes any advisors or experts that the Committee may hire, has adopted an investment strategy that divides its pension investment program into two primary portfolios:

- return seeking assets—those assets intended to generate returns in excess of pension liability growth, and
- liability hedging assets—those assets intended to have characteristics similar to pension liabilities.

Currently, the Committee allocates 60% of its plan assets to return seeking assets to help reduce existing deficits in the funded status of the plan. As the funded status of our plans improves, the Committee expects to reduce its exposure to return seeking assets and increase its liability hedging assets to reduce its total risk.

<u>*Return Seeking Assets*</u>

The purpose of return seeking assets is to provide investment returns in excess of the growth of pension liabilities. This category includes a diversified portfolio of public equities, private equity, real estate, hedge funds, high yield bonds and other instruments. These assets are likely to have lower correlations with the pension liabilities and lead to higher funded status risk over shorter periods of time.

Liability Hedging Assets

The purpose of liability hedging assets, such as long duration bonds and interest rate derivatives, is to hedge against interest rate changes. Exposure to liability hedging assets is intended to reduce the volatility of plan funded status, contributions, and pension expense.

Risk Management

The Committee manages plan asset risk using several approaches. First, the assets are invested in two diverse portfolios: a growth portfolio and a portfolio that hedges changes in the liability due to interest rate movement. Each portfolio contains investments across a spectrum of asset classes. Second, the Committee considers the long-term investment horizon of the plan, which is greater than ten years. The long-term horizon enables the Committee to tolerate the risk of investment losses in the short-term with the expectation of higher returns in the long-term. Third, the Committee employs a thorough due diligence program prior to selecting an investment, and a rigorous ongoing monitoring program once assets are invested. The Committee evaluates risk on an ongoing basis.

Asset Allocation

Plan assets are diversified across various asset classes and securities based on the investment strategy approved by the Committee. This policy allocation is long-term oriented and consistent with the risk tolerance and funded status. The target asset allocation as well as the actual allocations for 2011 and 2010 are provided below.

	Target Allocation		Actual Allocation	
At December 31,	**2011**	2010	**2011**	2010
Global equity securities	**42%**	42%	**38%**	42%
Fixed income securities	**40**	40	**42**	37
Alternative investments	**12**	12	**11**	8
High yield bonds	**6**	6	**6**	6
Cash and cash equivalents	**—**	—	**3**	7
Derivative instruments	**—**	—	**—**	—
Total	**100%**	100%	**100%**	100%

The target asset allocation allows for investments in financial derivatives to hedge against liability changes caused by interest rate movement and capture security price volatility. These instruments are sensitive to changes in economic conditions.

The Committee will also rebalance our portfolio periodically when the actual allocations fall outside of the ranges prescribed in the investment policy or as the funded status improves.

Fair Value Hierarchy

We determine the fair value of the plan assets using unadjusted quoted prices in active markets (Level 1) or pricing inputs that are observable (Level 2) whenever that information is available. We use unobservable inputs (Level 3) to estimate fair value only when relevant observable inputs are not available. We classify assets within this fair value hierarchy based on the lowest level of input that is significant to the fair value measurement of each individual asset taken as a whole.

The following tables set forth by level, within the fair value hierarchy, the investments in the Plans' master trust at fair value as of December 31, 2011 and 2010:

At December 31, 2011	Level 1	Level 2	Level 3	Total Fair Value
		(In millions)		
Global equity securities:				
Money market funds (1)	$ 22.6	$ —	$ —	$ 22.6
Marketable equity securities	125.5	—	—	125.5
Common collective trusts	—	420.4	—	420.4
Mutual funds	2.2	—	—	2.2
Fixed income securities:				
Money market funds (1)	20.4	—	—	20.4
Corporate debt securities	—	327.3	—	327.3
Government / agency securities	—	178.2	—	178.2
Municipal bonds	—	73.3	—	73.3
Guarantee insurance contracts	—	20.6	—	20.6
Asset and mortgage-backed securities	—	1.8	—	1.8
Mutual funds	1.0	—	—	1.0
High yield bonds:				
Money market funds (1)	5.4	—	—	5.4
Corporate debt securities	—	76.9	—	76.9
Cash equivalents	49.0	—	—	49.0
Derivative instruments	—	0.4	—	0.4
Alternative investments	—	—	162.7	162.7
Total	$226.1	$1,098.9	$162.7	$1,487.7

(1) *Money market funds available for the portfolio manager to invest have been included within the respective security classification to differentiate from the actual cash position of the pension trust.*

At December 31, 2010	Level 1	Level 2	Level 3	Total Fair Value
		(In millions)		
Global equity securities:				
Money market funds (1)	$ 26.1	$ —	$ —	$ 26.1
Marketable equity securities	143.6	—	—	143.6
Common collective trusts	—	421.4	—	421.4
Fixed income securities:				
Money market funds (1)	9.8	—	—	9.8
Corporate debt securities	—	318.0	—	318.0
Government / agency securities	—	112.7	—	112.7
Municipal bonds	—	54.8	—	54.8
Guarantee insurance contracts	—	21.6	—	21.6
Asset and mortgage-backed securities	—	0.4	—	0.4
High yield bonds:				
Money market funds (1)	4.7	—	—	4.7
Corporate debt securities	—	82.2	—	82.2
Cash equivalents	93.6	—	—	93.6
Derivative instruments	—	0.9	—	0.9
Alternative investments	—	—	118.3	118.3
Total	$277.8	$1,012.0	$118.3	$1,408.1

(1) Money market funds available for the portfolio manager to invest have been included within the respective security classification to differentiate from the actual cash position of the pension trust.

The following is a description of the valuation methodologies used for assets measured at fair value:

- Global equity securities, which include marketable equity securities common collective trust securities, and mutual funds are valued at unadjusted quoted market share prices within active markets (Level 1) or based on external price/spread data of comparable securities (Level 2). Common collective trust funds within this category are valued at fair value based on the unit value of the fund which is observable on a less frequent basis (Level 2). Unit values are determined by the bank or financial institution sponsoring such funds by dividing the fund's net assets at fair value by its units outstanding at the valuation dates.
- Fixed income (primarily corporate debt securities, government and agency securities, municipal bonds, guarantee insurance contracts, asset and mortgage-backed securities, and mutual funds), high yield bonds, and over-the-counter derivatives are valued based on external price data of comparable securities (Level 2).
- Cash equivalents consist of money market funds, which are valued by multiplying unadjusted quoted prices in active markets by the quantity of the assets (Level 1).
- Alternative investments primarily consist of hedge funds, real estate funds, and financial limited partnerships (private equity funds). These investments do not have readily determinable fair values because they are not listed on national exchanges or over-the-counter markets. We have valued these alternative investments at their respective net asset value per share (or its equivalent such as partner's capital) which has been calculated by each partnership's general partner in a manner consistent with generally accepted accounting principles in the United States of America for investment companies. Among other requirements, the partnerships must value their underlying investments at fair value. While the net asset value per share provides a reasonable approximation of fair value, the fair values of the alternative investments are estimates and, accordingly, such estimated values may differ from the values that would have been used had a ready market for the investments existed, and the differences could be material.

The following table summarizes the changes in the fair value of the Level 3 assets for the years ended December 31, 2011 and 2010:

	Year Ended December 31,	
	2011	2010
	(In millions)	
Balance at beginning of period	**$ 118.3**	$ 74.4
Actual return on plan assets:		
Assets still held at year end	**(11.1)**	(32.1)
Assets sold during the year	**7.4**	37.0
Purchases	**160.3**	
Sales	**(112.2)**	
Net purchases, sales, and settlements	**48.1**	22.2
Transfers into Level 3	**—**	16.8
Transfers out of Level 3	**—**	—
Balance at end of year	**$ 162.7**	$118.3

Contributions and Benefit Payments

We contributed $75.6 million to our qualified pension plans in 2011, of which $53.6 million was contributed by BGE. $75.0 million of this contribution was an acceleration of estimated calendar year 2012 contributions. Therefore, we do not plan to make contributions to our qualified pension plans in 2012. Our non-qualified pension plans and our postretirement benefit programs are not funded. We estimate that we will incur approximately $5 million in pension benefits for our non-qualified pension plans and approximately $22 million for retiree health and life insurance costs net of Medicare Part D during 2012.

Other Postemployment Benefits

We provide the following postemployment benefits:

- health and life insurance benefits to eligible employees determined to be disabled under our Disability Insurance Plan, and
- income replacement payments for employees determined to be disabled before November 1995 (payments for employees determined to be disabled after that date are paid by an insurance company, and the cost is paid by employees).

We recognized expense associated with our other postemployment benefits of $3.0 million in 2011, $9.9 million in 2010, and $5.3 million in 2009. BGE's portion of expense associated with other postemployment benefits was $2.8 million in 2011, $7.6 million in 2010, and $4.4 million in 2009.

We assumed the discount rate for other postemployment benefits to be 3.00% as of December 31, 2011 and 4.00% as of December 31, 2010. This assumption impacts the calculation of our other postemployment benefit obligation and periodic cost.

Employee Savings Plan Benefits

We sponsored two defined contribution plans until November 6, 2009, when upon the close of the sale of a 49.99% interest in CENG to EDF, we deconsolidated CENG and the defined contribution plan related to Nine Mile Point was removed from our books. For all remaining eligible employees of Constellation Energy, we continue to sponsor a defined contribution savings plan. The savings plan is a qualified 401(k) plan under the Internal Revenue Code. In a defined contribution plan, the benefits a participant is to receive result from regular contributions to a participant account. Matching contributions to participant accounts are made under these plans. Matching contributions were as follows:

Year Ended December 31,	**2011**	2010	2009
		(In millions)	
Nonregulated businesses	**$10.1**	$ 9.9	$14.8
BGE	**6.6**	6.3	5.7
Total Constellation Energy	**$16.7**	$16.2	$20.5

8 Credit Facilities and Short-Term Borrowings

Our short-term borrowings may include bank loans, commercial paper, and bank lines of credit. Short-term borrowings mature within one year from the date of issuance. We pay commitment fees to banks for providing us lines of credit. When we borrow under the lines of credit, we pay market interest rates. We enter into these facilities to ensure adequate liquidity to support our operations.

Constellation Energy

Our liquidity requirements are funded with credit facilities and cash. We fund our short-term working capital needs with existing cash and with our credit facilities, which support direct cash borrowings and the issuance of commercial paper, if available. We also use our credit facilities to support the issuance of letters of credit, primarily for our NewEnergy business.

Constellation Energy had bank lines of credit under committed credit facilities totaling $4.2 billion at December 31, 2011 for short-term financial needs as follows:

Type of Credit Facility	Amount (In billions)	Expiration Date	Capacity Type
Syndicated Revolver(1)	$ 2.50	October 2013	Letters of credit and cash
Commodity-linked	0.50	August 2014	Letter of credit and cash
Bilateral	0.55	September 2014	Letters of credit
Bilateral	0.25	December 2014	Letters of credit and cash
Bilateral	0.25	June 2014	Letters of credit and cash
Bilateral	0.15	September 2013	Letters of credit
Total	$ 4.20		

(1) Upon closing of the merger with Exelon, the amount available under this facility will be $1.5 billion.

At December 31, 2011, we had approximately $1.5 billion in letters of credit issued, including $0.5 billion in letters of credit issued under the commodities-linked credit facility discussed below, and no commercial paper outstanding under these facilities.

The commodity-linked credit facility currently allows for the issuance of letters of credit and, as modified in 2010, for cash borrowings, up to a maximum capacity of $0.5 billion. This commodity-linked facility is designed to help manage our contingent collateral requirements associated with the hedging of our NewEnergy business because its capacity increases up to the maximum capacity as natural gas price levels decrease compared to a reference price that is adjusted periodically.

At December 31, 2011, Constellation Energy had $39.5 million of short-term notes outstanding with a weighted-average effective interest rate of 2.59%.

BGE

BGE has a $600.0 million revolving credit facility expiring in March 2015. BGE can borrow directly from the banks, use the facility to allow commercial paper to be issued, if available, or issue letters of credit. At December 31, 2011, BGE had no commercial paper outstanding. There were immaterial letters of credit outstanding at December 31, 2011.

Net Available Liquidity

The following table provides a summary of our net available liquidity at December 31, 2011:

At December 31, 2011	Constellation Energy (excluding BGE)	BGE
	(In billions)	
Credit facilities (1)	$ 3.7	$ 0.6
Less: Letters of credit issued (1)	(1.0)	—
Less: Cash drawn on credit facilities	—	—
Undrawn facilities	2.7	0.6
Less: Commercial paper outstanding	—	—
Net available facilities	2.7	0.6
Add: Cash and cash equivalents (2)	0.9	—
Net available liquidity	$ 3.6	$ 0.6

(1) Excludes $0.5 billion commodity-linked credit facility due to its contingent nature and $0.5 billion in letters of credit posted against it.
(2) BGE's cash balance at December 31, 2011 was $48.6 million.

Credit Facility Compliance and Covenants

The credit facilities of Constellation Energy and BGE contain a material adverse change representation but draws on the facilities are not conditioned upon Constellation Energy and BGE making this representation at the time of the draw. However, to the extent a material adverse change has occurred and prevents Constellation Energy or BGE from making other representations that are required at the time of the draw, the draw would be prohibited.

Certain credit facilities of Constellation Energy contain a provision requiring Constellation Energy to maintain a ratio of debt to capitalization equal to or less than 65%. At December 31, 2011, the debt to capitalization ratio as defined in the credit agreements was 38%.

The credit agreement of BGE contains a provision requiring BGE to maintain a ratio of debt to capitalization equal to or less than 65%. At December 31, 2011, the debt to capitalization ratio for BGE as defined in this credit agreement was 46%.

Decreases in Constellation Energy's or BGE's credit ratings would not trigger an early payment on any of our, or BGE's, credit facilities. However, the impact of a credit ratings downgrade on our financial ratios associated with our credit facility covenants would depend on our financial condition at the time of such a downgrade and on the source of funds used to satisfy the incremental collateral obligation resulting from a credit ratings downgrade. For example, if we were to use existing cash balances to fund the cash portion of any additional collateral obligations resulting from a credit ratings downgrade, we would not expect a material impact on our financial ratios. However, if we were to issue long-term debt or use our credit facilities to fund any additional collateral obligations, our financial ratios could be materially affected. Failure by Constellation Energy, or BGE, to comply with these covenants could result in the acceleration of the maturity of the borrowings outstanding and preclude us from issuing letters of credit under these facilities.

9 Capitalization

We detail in the table below our total capitalization, which includes long-term debt, common stock, noncontrolling interests, and preference stock, as of December 31, 2011 and 2010.

At December 31,	**2011**	2010
	(In millions)	
Long-Term Debt		
Long-term debt of Constellation Energy		
8.625% Series A Junior Subordinated Debentures, due June 15, 2063	**$ 450.0**	$ 450.0
7.00% Fixed-Rate Notes, due April 1, 2012	**—**	213.5
4.55% Fixed-Rate Notes, due June 15, 2015	**550.0**	550.0
5.15% Fixed-Rate Notes, due December 1, 2020	**550.0**	550.0
7.60% Fixed-Rate Notes, due April 1, 2032	**700.0**	700.0
Fair Value of Interest Rate Swaps	**44.1**	36.2
Total long-term debt of Constellation Energy	**2,294.1**	2,499.7
Long-term debt of nonregulated businesses		
Tax-exempt debt transferred from BGE effective July 1, 2000		
4.10% Pollution control loan, due July 1, 2014	**20.0**	20.0
Tax-exempt variable rate notes, due April 1, 2024	**75.0**	75.0
7.3% Fixed Rate Note, due June 1, 2012	**1.6**	1.7
Upstream Gas Property asset-based lending agreement due July 16, 2016	**83.0**	18.0
Secured Solar Credit Lending Agreement due July 7, 2014	**130.0**	—
Sacramento Solar Project Financing Agreement due December 31, 2030	**40.7**	—
Denver International Airport Solar Loan Agreement due June 30, 2031	**7.5**	—
Holyoke Solar, LLC Loan Agreement due December 31, 2031	**11.0**	—
Total long-term debt of nonregulated businesses	**368.8**	114.7
Other long-term debt of BGE		
3.50% Notes, due November 15, 2021	**300.0**	—
6.125% Notes, due July 1, 2013	**400.0**	400.0
5.90% Notes, due October 1, 2016	**300.0**	300.0
5.20% Notes, due June 15, 2033	**200.0**	200.0
6.35% Notes, due October 1, 2036	**400.0**	400.0
Medium-term notes, Series E	**109.6**	131.5
Total other long-term debt of BGE	**1,709.6**	1,431.5
6.20% deferrable interest subordinated debentures due October 15, 2043 to BGE wholly owned BGE Capital Trust II relating to trust preferred securities	**257.7**	257.7
Rate stabilization bonds	**394.6**	454.4
Unamortized discount and premium	**(5.1)**	(3.9)
Current portion of long-term debt	**(174.9)**	(305.3)
Total long-term debt	**$ 4,844.8**	$4,448.8
Equity:		
Noncontrolling Interests	**$ 116.9**	$ 88.8
BGE Preference Stock		

Cumulative preference stock not subject to mandatory redemption, 6,500,000 shares authorized 7.125%, 1993 Series, 400,000 shares outstanding, callable at $100.71 per share until June 30, 2012, and at lesser amounts thereafter	**40.0**	40.0
6.97%, 1993 Series, 500,000 shares outstanding, callable at $100.70 per share until September 30, 2012, and at lesser amounts thereafter	**50.0**	50.0
6.70%, 1993 Series, 400,000 shares outstanding, callable at $100.67 per share until December 31, 2012, and at lesser amounts thereafter	**40.0**	40.0
6.99%, 1995 Series, 600,000 shares outstanding, callable at $101.40 per share until September 30, 2012, and at lesser amounts thereafter	**60.0**	60.0
Total BGE preference stock not subject to mandatory redemption	**190.0**	190.0
Common Shareholders' Equity		
Common stock without par value, 600,000,000 shares authorized; 201,686,291 and 199,788,658 shares issued and outstanding at December 31, 2011 and 2010, respectively. (At December 31, 2011, 10,143,863 shares were reserved for the long-term incentive plans, 8,542,059 shares were reserved for the shareholder investment plan, and 1,223,050 shares were reserved for the employee savings plan.)	**3,292.2**	3,231.7
Retained earnings	**4,738.0**	5,270.8
Accumulated other comprehensive (loss) income:		
Hedging instruments	**(404.0)**	(228.7)
Available-for-sale securities	**38.9**	34.5
Defined benefit plans	**(558.3)**	(481.1)
Foreign currency translation and other	**(12.9)**	2.0
Total accumulated other comprehensive loss	**(936.3)**	(673.3)
Total common shareholders' equity	**7,093.9**	7,829.2
Total Equity	**7,400.8**	8,108.0
Total Capitalization	**$12,245.6**	$12,556.8

BGE Common Shareholder Equity

At December 31,	**2011**	2010
	(In millions)	
Common Stock	**$1,293.1**	$1,293.1
Retained Earnings	**817.0**	779.5
Accumulated other comprehensive income	**0.6**	0.6
Total BGE common shareholder equity	**$2,110.7**	$2,073.2

Long-term Debt

Long-term debt matures in one year or more from the date of issuance. The long-term debt of Constellation Energy and BGE do not contain material adverse change clauses. We detail our long-term debt in the table above.

Constellation Energy

5.15% Notes due December 1, 2020

In December 2010, we issued $550 million of 5.15% Notes due December 1, 2020. Interest is payable semi-annually on June 1 and December 1, beginning June 1, 2011. At any time prior to September 1, 2020, we may redeem some or all of the notes at a price equal to the greater of 100% of the principal amount of the notes outstanding to be redeemed and the sum of the present values of the remaining scheduled payments of principal and interest on the notes being redeemed, discounted to the redemption date on a semi-annual basis at the Treasury rate plus 30 basis points, plus accrued interest. After September 1, 2020, we may redeem some or all of the notes at a price equal to 100% of the principal amount of the notes outstanding to be redeemed plus accrued interest on the principal amount being redeemed to the redemption date.

Additionally, in December 2010, we issued a notice to redeem $213.5 million of our 7.00% Notes, which represented the remaining outstanding 7.00% Notes due April 1, 2012. As such, we classified these notes as "Current portion of long-term debt" in our Consolidated Balance Sheets. In January 2011, we redeemed these notes with part of the proceeds from the issuance of the $550 million 5.15% Notes, terminated the associated interest rate swaps, and recognized a pre-tax loss of approximately $5 million on this transaction.

During February 2011, we entered into interest rate swaps qualifying as fair value hedges related to $350 million of our fixed rate debt maturing in 2015. We also entered into $150 million of interest rate swaps related to our fixed rate debt maturing in 2020 that do not qualify as fair value hedges, and will be marked to market through earnings. These swaps effectively converted $500 million notional amount of fixed rate debt to floating rate for the term of the swaps.

We discuss our interest rate swaps in *Note 13*.

Secured Solar Credit Lending Agreement

In July 2011, a subsidiary of Constellation Energy entered into a three-year senior secured credit facility that is designed to support the growth of our solar operations. The amount committed under the facility is $150 million, which may be increased up to $200 million at the subsidiary's request with additional commitments by the lenders. At December 31, 2011, we had borrowed $130.0 million. Borrowings incur interest at a variable rate payable quarterly and are secured by the equity interests in the subsidiary and the entities that own the solar projects as well as the assets of the subsidiary and the projects' entities. The obligations of our subsidiary are guaranteed by Constellation Energy and the projects' entities. The Constellation Energy guarantee will terminate upon the subsidiary obtaining a stand-alone investment grade credit rating or the satisfaction of a number of conditions, at which time the financing will become nonrecourse to Constellation Energy.

Sacramento Solar Project Financing

In July 2011, a subsidiary of Constellation Energy entered into a $40.7 million nonrecourse project financing to fund construction of our 30MW solar facility in Sacramento, California. Borrowings will incur interest at a variable rate, payable quarterly, and are secured by the equity interests and assets of the subsidiary. The construction borrowings are expected to convert into a 19-year nonrecourse variable note in the first quarter of 2012. The subsidiary also executed interest rate swaps for a notional amount of $30.6 million in order to convert the variable interest payments to fixed payments on the $40.7 million facility amount. We discuss our use of derivative instruments, including interest rate swaps, to manage our interest rate risk in more detail in *Note 13*.

In addition to this facility, this subsidiary entered into a treasury grant bridge loan for $26.0 million and an equity bridge loan for $27.9 million. Both loans will be utilized to fund construction. The equity bridge loan is expected to be repaid in the first quarter of 2012 and the treasury grant is expected to be repaid in the second quarter of 2012.

Other Solar Project Financings

During 2011, we borrowed the following amounts under solar project loan agreements:

- $7.5 million due June 30, 2031 related to a solar project at the Denver International Airport, and
- $11.0 million due December 31, 2031 related to a solar project in Holyoke, Massachusetts.

Upstream Gas Property Asset-Based Lending Agreement

In July 2009, we entered into a three year asset-based lending agreement associated with certain upstream gas properties that we own. In July 2011, we amended and extended this lending agreement. The borrowing base committed under the facility was increased to $150 million and can increase to a total of $500 million if the assets support a higher borrowing base and we are able to obtain additional commitments from lenders. The facility now expires in July 2016. Borrowings under this facility are secured by the upstream gas properties, and the lenders do not have recourse against Constellation Energy in the event of a default. At December 31, 2011, we had borrowed $83.0 million under the facility with interest payable quarterly. The facility includes a provision that requires our entities that own the upstream gas properties subject to the agreement to maintain a current ratio of one-to-one. As of December 31, 2011, we are compliant with this provision.

BGE

3.50% Notes due November 15, 2021

In November 2011, BGE issued $300 million of 3.50% Notes due November 15, 2021. Interest is payable semi-annually on May 15 and November 15, beginning May 15, 2012. At any time prior to August 15, 2021, BGE may redeem some or all of the notes at a price equal to the greater of 100% of the principal amount of the notes outstanding to be redeemed and the sum of the present values of the remaining scheduled payments of principal and interest on the notes being redeemed, discounted to the redemption date on a semi-annual basis at the Treasury rate plus 25 basis points, plus accrued interest. After August 15, 2021, BGE may redeem some or all of the notes at a price equal to 100% of the principal amount of the notes outstanding to be redeemed plus accrued interest on the principal amount being redeemed to the redemption date.

Secured Indenture

BGE entered into a secured indenture in July 2009. The secured indenture creates a first priority lien on substantially all of BGE's electric utility distribution equipment and fixtures and on BGE's franchises, permits, and licenses that are transferable and necessary for the operation of the equipment and fixtures. As of December 31, 2011, BGE has not issued any secured bonds under this indenture.

BGE's Rate Stabilization Bonds

In June 2007, BondCo, a subsidiary of BGE, issued an aggregate principal amount of $623.2 million of rate stabilization bonds to recover deferred power purchase costs. We discuss BondCo in more detail in *Note 4*. Below are the details of the rate stabilization bonds at December 31, 2011:

Principal	Interest Rate	Scheduled Maturity Date
$55.4	5.47%	October 2012
220.0	5.72	April 2016
119.2	5.82	April 2017

The bonds are secured primarily by a usage-based, non-bypassable charge payable by all of BGE's residential electric customers over a ten year period. The charges will be adjusted semi-annually to ensure that the aggregate charges collected are sufficient to pay principal and interest on the bonds, as well as certain on-going costs of administering and servicing the bonds. BondCo cannot use the charges collected to satisfy any other obligations. BondCo's assets are not assets of any affiliate and are not available to pay creditors of any affiliate of BondCo. If BondCo is unable to make principal and interest payments on the bonds, neither Constellation Energy, nor BGE, are required to make the payments on behalf of BondCo.

BGE's Other Long-Term Debt

On July 1, 2000, BGE transferred $278.0 million of tax-exempt debt to our Generation business related to the transferred generating assets. At December 31, 2011, BGE remains contingently liable for the $20 million outstanding balance of this debt.

BGE's fixed-rate medium-term note, series E, outstanding at December 31, 2011 has a weighted average interest rate of 6.75%, maturing in 2012.

BGE Deferrable Interest Subordinated Debentures

On November 21, 2003, BGE Capital Trust II (BGE Trust II), a Delaware statutory trust established by BGE, issued 10,000,000 Trust Preferred Securities for $250 million ($25 liquidation amount per preferred security) with a distribution rate of 6.20%.

BGE Trust II used the net proceeds from the issuance of common securities to BGE and the Trust Preferred Securities to purchase a series of 6.20% Deferrable Interest Subordinated Debentures due October 15, 2043 (6.20% debentures) from BGE in the aggregate principal amount of $257.7 million with the same terms as the Trust Preferred Securities. BGE Trust II must redeem the Trust Preferred Securities at $25 per preferred security plus accrued but unpaid distributions when the 6.20% debentures are paid at maturity or upon any earlier redemption. BGE has the option to redeem the 6.20% debentures at any time in the future when certain tax or other events occur.

BGE Trust II will use the interest paid on the 6.20% debentures to make distributions on the Trust Preferred Securities. The 6.20% debentures are the only assets of BGE Trust II.

BGE fully and unconditionally guarantees the Trust Preferred Securities based on its various obligations relating to the trust agreement, indentures, 6.20% debentures, and the preferred security guarantee agreement.

For the payment of dividends and in the event of liquidation of BGE, the 6.20% debentures are ranked prior to preference stock and common stock.

Maturities of Long-Term Debt

As of December 31, 2011, our long-term borrowings mature on the following schedule:

Year	Constellation Energy	Nonregulated Businesses	BGE	Total
		(In millions)		
2012	$ —	$ 2.4	$ 172.5	$ 174.9
2013	—	2.5	466.6	469.1
2014	—	152.5	70.4	222.9
2015	594.1	2.6	74.5	671.2
2016	—	84.2	378.9	463.1
Thereafter	1,700.0	124.6	1,199.0	3,023.6
Total	$ 2,294.1	$ 368.8	$2,361.9	$5,024.8

Weighted-Average Interest Rates for Variable Rate Debt

Our weighted-average interest rates for variable rate debt outstanding were:

At December 31,	**2011**	2010
Nonregulated Businesses (including Constellation Energy)		
Loans under credit agreements	**2.88%**	4.50%
Tax-exempt debt	**0.21%**	0.30%
Fixed-rate debt converted to floating (1)	**1.55%**	1.23%

(1) Includes $150 million of floating rate swaps related to fixed rate debt maturing in 2020 for four years of the 10-year term note.

Preference Stock

Each series of BGE preference stock has no voting power, except for the following:

- the preference stock has one vote per share on any charter amendment which would create or authorize any shares of stock ranking prior to or on a parity with the preference stock as to either dividends or distribution of assets, or which would substantially adversely affect the contract rights, as expressly set forth in BGE's charter, of the preference stock, each of which requires the affirmative vote of two-thirds of all the shares of preference stock outstanding; and
- whenever BGE fails to pay full dividends on the preference stock and such failure continues for one year, the preference stock shall have one vote per share on all matters, until and unless such dividends shall have been paid in full. Upon liquidation, the holders of the preference stock of each series outstanding are entitled to receive the par amount of their shares and an amount equal to the unpaid accrued dividends.

Dividend Restrictions

Constellation Energy

Constellation Energy pays dividends on its common stock after its Board of Directors declares them. There are no contractual limitations on Constellation Energy paying common stock dividends, unless Constellation Energy elects to defer interest payments on the 8.625% Series A Junior Subordinated Debentures due June 15, 2063, and any deferred interest remains unpaid. The merger agreement with Exelon prohibits us from increasing our common stock dividend without Exelon's consent.

BGE

BGE pays dividends on its common stock after its Board of Directors declares them. However, pursuant to the order issued by the Maryland PSC on October 30, 2009 in connection with its approval of the transaction with EDF, BGE cannot pay dividends to Constellation Energy if (a) after the dividend payment, BGE's equity ratio would be below 48% as calculated pursuant to the Maryland PSC'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.

10 Taxes

The components of income tax expense are as follows:

Year Ended December 31,	**2011**	2010	2009
	(Dollar amounts in millions)		
Income Taxes			
Current			
Federal	**$ (56.0)**	$ (46.9)	$ 891.5
State	**23.2**	102.0	260.4
Current taxes charged to expense	**(32.8)**	55.1	1,151.9
Deferred			
Federal	**(134.1)**	(521.4)	1,474.5
State	**(59.7)**	(194.9)	372.5
Deferred taxes (credited) charged to expense	**(193.8)**	(716.3)	1,847.0
Investment tax credit adjustments	**(4.3)**	(4.5)	(12.1)
Income taxes per Consolidated Statements of Income (Loss)	**$(230.9)**	$(665.7)	$2,986.8

Total income taxes are different from the amount that would be computed by applying the statutory Federal income tax rate of 35% to book income before income taxes as follows:

Reconciliation of Income Taxes Computed at Statutory Federal Rate to Total Income Taxes			
(Loss) Income from continuing operations before income taxes	**$(537.7)**	$(1,597.5)	$7,490.2
Statutory federal income tax rate	**35%**	35%	35%
Income taxes computed at statutory federal rate	**(188.2)**	(559.1)	2,621.6
Increases (decreases) in income taxes due to			
State income taxes, net of federal income tax benefit	**(23.8)**	(60.4)	411.0
Merger-related transaction costs	**—**	—	(79.3)
Interest expense on mandatorily redeemable preferred stock	**—**	—	23.7
Qualified decommissioning impairment losses	**—**	—	3.1
Amortization of deferred investment tax credits	**(4.3)**	(4.5)	(12.1)
Noncontrolling interest operating results	**(7.1)**	(13.1)	(16.4)
Nondeductible international losses	**—**	—	19.2
Other	**(7.5)**	(28.6)	16.0
Total income taxes	**$(230.9)**	$ (665.7)	$2,986.8
Effective income tax rate	**42.9%**	41.7%	39.9%

BGE’s effective tax rate was 35.1% in 2011, 39.7% in 2010, and 41.3% in 2009. In general, the primary difference between BGE’s effective tax rate and the 35% statutory federal income tax rate for all years relates to Maryland corporate income taxes, net of the related federal income tax benefit. The decrease in BGE’s effective tax rate in 2011 is primarily due to the favorable impact from the IRS National Office guidance regarding BGE’s change of accounting for tax purposes with respect to certain electric transmission and distribution expenditures and the partial reversal of an unfavorable deferred tax adjustment recorded in 2010 as a result of healthcare reform legislation that eliminated the tax exempt treatment of prescription drug subsidies received under Medicare Part D. The partial reversal in 2011 resulted from the Maryland PSC’s authorization for BGE to create an electric regulatory asset for this tax law change and amortize the balance over a five-year period. The decrease in BGE’s 2010 effective tax rate from 2009 is primarily due to the inclusion of a minority interest loss in pre-tax earnings in 2009 that was not included in 2010 pre-tax earnings because of BGE’s sale of the interest in January 2010.

The major components of our net deferred income tax liability are as follows:

At December 31,	Constellation Energy 2011	Constellation Energy 2010	BGE 2011	BGE 2010
	(In millions)			
Deferred Income Taxes				
Deferred tax liabilities				
Net property, plant and equipment	**$2,020.4**	$1,768.3	**$1,220.1**	$1,152.3
Regulatory assets, net	**282.6**	256.8	**282.6**	256.8
Derivative assets and liabilities, net	**(84.6)**	(34.1)	**—**	—
Investment in CENG	**604.5**	1,044.3	**—**	—
Other	**156.3**	12.1	**21.6**	(80.0)
Total deferred tax liabilities	**2,979.2**	3,047.4	**1,524.3**	1,329.1
Deferred tax assets				
Defined benefit obligations	**305.0**	249.0	**(93.1)**	(79.7)
Financial investments and hedging instruments	**217.6**	111.4	**—**	—
Asset retirement obligations	**10.9**	10.9	**—**	—
Deferred investment tax credits	**9.6**	10.9	**3.1**	3.2
Other	**263.0**	118.9	**71.1**	20.6
Total deferred tax assets	**806.1**	501.1	**(18.9)**	(55.9)
Total deferred tax liability, net	**2,173.1**	2,546.3	**1,543.2**	1,385.0
Less: Current portion of deferred tax liability/(asset)	**(132.0)**	56.5	**59.0**	30.1
Long-term portion of deferred tax liability, net	**$2,305.1**	$2,489.8	**$1,484.2**	$1,354.9

Income Tax Audits

We file income tax returns in the United States and foreign jurisdictions. With few exceptions, we are no longer subject to U.S. federal, state and local, or non-U.S. income tax examinations by tax authorities for the years before 2008. In August 2011, we formally agreed to an assessment of tax by the IRS for the 2005 - 2007 tax years. The assessment did not have a material impact on our, or BGE's, financial condition or results of operation.

The IRS has audited our consolidated federal income tax return for the 2008 tax year and completion of the audit is awaiting additional industry guidance from the IRS National Office regarding BGE's change of accounting for tax purposes with respect to certain electric and gas transmission and distribution expenditures. IRS industry guidance on electric transmission and distribution expenditures was issued in August 2011 and additional guidance on gas transmission and distribution expenditures is expected in 2012. Application and compliance with the IRS industry guidance for electric and gas transmission and distribution expenditures should result in the completion of the IRS examination for the 2008 tax year. The IRS is also currently auditing our consolidated federal income tax returns for the 2009 - 2010 tax years as well as examining the 2011 tax year concurrently as part of the IRS Compliance Assurance Process. Although the final outcome of the 2008 - 2011 IRS audit and future tax audits is uncertain, we believe that adequate provisions for income taxes have been made for potential liabilities resulting from such matters.

Unrecognized Tax Benefits

The following table summarizes the change in unrecognized tax benefits during 2011 and 2010 and our total unrecognized tax benefits at December 31, 2011 and 2010:

	2011	2010
	(In millions)	
Total unrecognized tax benefits, January 1	$239.8	$ 312.5
Increases in tax positions related to the current year	3.1	5.9
Increases in tax positions related to prior years	29.6	26.0
Reductions in tax positions related to prior years	(90.6)	(104.0)
Reductions in tax positions as a result of a lapse of the applicable statute of limitations	(0.8)	(0.6)
Total unrecognized tax benefits, December 31 (1)	$181.1	$ 239.8

(1) BGE's portion of our total unrecognized tax benefits at December 31, 2011 and 2010 was $11.4 million and $72.9 million, respectively.

If the total amount of unrecognized tax benefits of $181.1 million were ultimately realized, our income tax expense would decrease by approximately $169 million. However, the $169 million includes state tax refund claims of $55.9 million that have been disallowed by tax authorities and are subject to appeals.

It is reasonably possible that unrecognized tax benefits could decrease within the next year by approximately $108 million as a result of a potential resolution with the IRS regarding BGE's change of accounting method for tax purposes with respect to certain gas transmission and distribution expenditures and certain state positions that are currently under audit or litigation. This decrease is not expected to have a material impact on our, or BGE's, financial condition or results of operation.

The decrease in unrecognized tax positions for the year ended December 31, 2011 is primarily related to the issuance of guidance from the IRS National Office in August 2011 regarding electric transmission and distribution expenditures. The decrease did not have a material impact on BGE's financial condition or results of operations.

Interest and penalties recorded in our Consolidated Statements of Income (Loss) as tax expense (benefit) relating to liabilities for unrecognized tax benefits were as follows:

	For the Year Ended December 31,		
	2011	2010	2009
		(In millions)	
Interest and penalties recorded as tax expense (benefit)	**$6.1**	$(6.3)	$12.8

BGE's portion of interest and penalties was immaterial for all years.

Accrued interest and penalties recognized in our Consolidated Balance Sheets were $22.9 million, of which BGE's portion was $1.2 million at December 31, 2011, and $16.8 million, of which BGE's portion was $3.8 million, at December 31, 2010.

11 Leases

There are two types of leases—operating and capital. Capital leases qualify as sales or purchases of property and are reported in our Consolidated Balance Sheets. Our capital leases are not material in amount. All other leases are operating leases and are reported in our Consolidated Statements of Income (Loss). We expense all lease payments associated with our regulated business. Lease expense and future minimum payments for long-term, noncancelable, operating leases are not material to BGE's financial results. We present information about our operating leases below.

Outgoing Lease Payments

We, as lessee, lease certain facilities and equipment. The lease agreements expire on various dates and have various renewal options. We also enter into certain power purchase agreements which are accounted for as operating leases. We classify power purchase agreements as leases if the agreement in substance provides us the ability to control the use of the underlying power generating facilities.

Under these agreements, we are required to make fixed capacity payments, as well as variable payments based on actual output of the plants. We record these payments as "Fuel and purchased energy expenses" in our Consolidated Statements of Income (Loss). We exclude from our future minimum lease payments table the variable payments related to the output of the plant due to the contingency associated with these payments.

Through March 2009, we managed a global coal and logistics services operation. We entered into time charter purchase agreements which entitled us to the use of dry bulk freight vessels in connection with this operation. We continue to manage a residual position, which was not divested in 2009 with the remainder of the operation. Certain of these contracts must be accounted for as leases. These arrangements do not include provisions for material rent increases and do not have provisions for rent holidays, contingent rentals or other incentives. In 2011, 2010, and 2009, we recognized aggregate lease expense of approximately $7 million, $11 million and $145 million, respectively, related to 3, 12 and 31 dry bulk freight vessels, respectively, hired under time charter arrangements. We record the payments as "Fuel and purchased energy expenses" in our Consolidated Statements of Income (Loss).

We recognized expense related to our operating leases as follows:

	Fuel and purchased energy expenses	Operating expenses	Total
		(In millions)	
2011	$ 291.1	$ 31.7	$322.8
2010	227.9	30.2	258.1
2009	385.6	37.2	422.8

At December 31, 2011, we owed future minimum payments for long-term, noncancelable, operating leases as follows:

Year	Power Purchase Agreements	Other	Total
		(In millions)	
2012	$ 198.2	$ 32.0	$ 230.2
2013	190.9	29.6	220.5
2014	193.8	33.8	227.6
2015	193.3	19.8	213.1
2016	108.2	12.9	121.1
Thereafter	51.9	17.1	69.0
Total future minimum lease payments	$ 936.3	$145.2	$1,081.5

Sub-Lease Arrangements

In managing the residual position from our former coal and logistics services operation, we provide time charters of dry bulk freight vessels to global customers that qualify as sub-leases of our time charter purchase contracts. In 2011, 2010, and 2009, we recorded sub-lease income of approximately $2 million, $25 million and $114 million, respectively, related to our time charter sub-leases. We record sub-lease income as part of "Nonregulated revenues" in our Consolidated Statements of Income (Loss).

12 Commitments, Guarantees, and Contingencies

Commitments

We have made substantial commitments in connection with our Generation, NewEnergy, and regulated electric and gas, and other nonregulated businesses. These commitments relate to:

- purchase of electric generating capacity and energy,
- procurement and delivery of fuels,
- the capacity and transmission and transportation rights for the physical delivery of energy to meet our obligations to our customers, and
- service agreements, capital for construction programs, and other.

Our Generation and NewEnergy businesses enter into various contracts for the procurement and delivery of fuels to supply our generating plant requirements. In most cases, our contracts contain provisions for price escalations, minimum purchase levels, and other financial commitments. These contracts expire in various years between 2012 and 2030. In addition, our NewEnergy business enters into contracts for the purchase of energy, capacity and transmission rights for the delivery of energy to meet our physical obligations to our customers. These contracts expire in various years between 2012 and 2031.

Our Generation and NewEnergy businesses also have committed to service agreements and other purchase commitments for our plants.

Our regulated electric business enters into various long-term contracts for the procurement of electricity. As of December 31, 2011, these contracts expire between 2012 and 2014 and represent BGE's estimated requirements to serve residential and small commercial customers as follows:

Contract Duration	*Percentage of Estimated Requirements*
From January 1, 2012 to September 2012	100%
From October 2012 to May 2013	75
From June 2013 to September 2013	50
From October 2013 to May 2014	25

The cost of power under these contracts is recoverable under the Provider of Last Resort agreement reached with the Maryland PSC discussed in *Note 1*, and therefore are excluded from the table later in this Note.

Our regulated gas business enters into various contracts for the procurement, transportation, and storage of gas. Our regulated gas business has gas procurement contracts that expire between 2012 and 2014 and transportation and storage contracts that expire between 2012 and 2027. The cost of gas under these contracts is recoverable under BGE's gas cost adjustment clause discussed in *Note 1*, and therefore are excluded from the table later in this Note.

We have also committed to service agreements and other obligations related to our information technology systems.

At December 31, 2011, we estimate our future obligations to be as follows:

	Payments				
	2012	2013-2014	2015-2016	Thereafter	Total
	(In millions)				
Competitive Businesses:					
Purchased capacity and energy	$ 501.1	$ 552.5	$ 338.5	$ 335.3	$1,727.4
Purchased energy from CENG (1)	1,000.0	2,075.3	1,566.7		4,642.0
Fuel and transportation	656.1	638.6	419.6	321.2	2,035.5
Long-term service agreements, capital, and other	22.9	6.3	2.4	0.9	32.5
Total competitive businesses	2,180.1	3,272.7	2,327.2	657.4	8,437.4
Corporate and Other:					
Long-term service agreements, capital, and other	190.4	52.1	43.7	96.9	383.1
Regulated:					
Purchase obligations and other	7.3	9.6	—	—	16.9
Total future obligations	$2,377.8	$3,334.4	$2,370.9	$ 754.3	$8,837.4

(1) As part of reaching a comprehensive agreement with EDF in October 2010, we modified our existing power purchase agreement with CENG to be unit contingent through the end of its original term in 2014. Additionally, beginning in 2015 and continuing to the end of the life of the respective plants, we agreed to purchase 50.01% of the available output of CENG's nuclear plants at market prices. We have included in the table our commitments under this agreement for five years, the time period for which we have more reliable data. Further, we continue to own a 50.01% membership interest in CENG that we account for as an equity method investment. See Note 16 for more details on this agreement.

Long-Term Power Sales Contracts

We enter into long-term power sales contracts in connection with our load-serving activities. We also enter into long-term power sales contracts associated with certain of our owned and contracted power producing facilities. Our load-serving power sales contracts extend for terms through 2031 and provide for the sale of energy to electric distribution utilities and certain retail customers. Our power sales contracts associated with our power producing facilities, including renewable energy, extend for terms into 2036 and provide for the sale of all or a portion of the actual output of certain of our owned and contracted power producing facilities. Substantially all long-term contracts were executed at pricing that approximated market rates, including profit margin, at the time of execution.

Guarantees

Our guarantees do not represent incremental Constellation Energy obligations; rather they primarily represent parental guarantees of subsidiary obligations. The following table summarizes the maximum exposure by guarantor based on the stated limit of our outstanding guarantees:

At December 31, 2011	*Stated Limit* (In billions)
Constellation Energy guarantees	$ 9.0
BGE guarantees	0.3
Total guarantees	$ 9.3

At December 31, 2011, Constellation Energy had a total of $9.3 billion in guarantees outstanding related to loans, credit facilities, and contractual performance of certain of its subsidiaries as described below.

- Constellation Energy guaranteed a face amount of $9.0 billion as follows:
  - $8.5 billion on behalf of our Generation and NewEnergy business to allow it the flexibility needed to conduct business with counterparties without having to post other forms of collateral. Our estimated net exposure for obligations under commercial transactions covered by these guarantees was approximately $1.5 billion at December 31, 2011, which represents the total amount the parent company could be required to fund based on December 31, 2011 market prices. For those guarantees related to our derivative liabilities, the fair value of the obligation is recorded in our Consolidated Balance Sheets.
  - $0.5 billion primarily on behalf of CENG's nuclear generating facilities for nuclear insurance and credit support to ensure these plants have funds to meet expenses and obligations to safely operate and maintain the plants. We recorded the fair value of $11.1 million for these guarantees on our Consolidated Balance Sheets.
- BGE guaranteed the Trust Preferred Securities of $250.0 million of BGE Capital Trust II.

Contingencies
Litigation

In the normal course of business, we are involved in various legal proceedings. We discuss the significant matters below.

Merger with Exelon

In late April and early May 2011, shortly after Constellation Energy and Exelon announced their agreement to merge the two companies, twelve shareholder class action lawsuits were filed in the Circuit Court for Baltimore City in Maryland. Each class action suit was filed on behalf of a proposed class of the shareholders of Constellation Energy against Constellation Energy, members of Constellation Energy's board of directors, and Exelon. The shareholder class actions generally allege that the individual directors breached their fiduciary duties by entering into the proposed merger because they failed to maximize the value that the shareholders would receive from the merger, and failed to disclose adequately all material information relating to the proposed merger. The class actions also allege that Constellation Energy and Exelon aided and abetted the individual directors' breaches of their fiduciary duties. The lawsuits challenge the proposed merger, seek to enjoin a shareholder vote on the proposed merger until all material information is provided relating to the proposed merger, and ask for rescission of the proposed merger and any related transactions that have been completed as of the date that the court grants any relief. The class action lawsuits also seek certification as class actions, compensatory damages, costs and disbursements related to the action, including attorneys' and experts' fees, and rescission damages. Plaintiffs in three of the twelve lawsuits subsequently filed motions to consolidate all the lawsuits. The court has granted the motion to consolidate.

In August 2011, two shareholder class action lawsuits were filed in the United States District Court for the District of Maryland. The class actions generally assert that Constellation Energy's directors breached their fiduciary duties to Constellation Energy's shareholders in connection with the pending merger and that Constellation Energy's directors, Constellation Energy, and Exelon aided and abetted the alleged breaches and that Constellation Energy's directors, Constellation Energy and/or Exelon violated Section 14(a) of the Securities Exchange Act of 1934 based on alleged material misrepresentations and omissions in the preliminary joint proxy statement/prospectus filed on June 27, 2011. The class actions seek various forms of relief, including, among other things, a declaratory judgment, an injunction prohibiting the merger, fees, expenses, and other costs.

In the third quarter of 2011, the parties to the consolidated action in the state court and the two actions in the federal court entered into a memorandum of understanding setting forth an agreement in principle regarding the settlement of the actions. Under the agreement, Constellation Energy and Exelon agreed to provide certain additional disclosures in the joint proxy statement/prospectus relating to the merger. The agreement provides that the actions will be dismissed with prejudice and that the members of the class of Constellation Energy shareholders will release the defendants from all claims that were or could have been raised in the actions, including all claims relating to the merger. The agreement also provides that the plaintiffs' counsel may apply to the state court for an award of attorney's fees and expenses. The settlement is subject to customary conditions, including, among other things, the execution of definitive settlement papers and approval of the settlement by the state court.

Constellation Energy and Constellation Energy's directors believe the actions are without merit and that they have valid defenses to all claims asserted therein. They entered into the memorandum of understanding solely to eliminate the burden, expense, and uncertainties inherent in further litigation. If the state court does not approve the settlement or any of the other conditions to consummation of the settlement are not satisfied, Constellation Energy and Constellation Energy's directors will continue to defend their positions in these matters vigorously.

Securities Class Action

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

The Southern District of New York granted the defendants' motion to transfer the two securities class actions filed in Maryland to the District of Maryland, and the actions have since been transferred for coordination with the securities class action filed there. On June 18, 2009, the court appointed a lead plaintiff, who filed a consolidated amended complaint on September 17, 2009. On November 17, 2009, the defendants moved to dismiss the consolidated amended complaint in its entirety. On August 13, 2010, the District Court of Maryland issued a ruling on the motion to dismiss, holding that the plaintiffs failed to state a claim with respect to the claims of the common shareholders under the Securities Exchange Act of 1934 and limiting the suit to those persons who purchased Debentures in the June 2008 offering. In August 2011, plaintiffs requested permission from the court to file a third amended complaint in an effort to attempt to revive the claims of the common shareholders. Constellation Energy has filed an objection to the plaintiffs' request for permission to file a third amended complaint. Given that limited discovery has occurred, that the court has not certified any class and the plaintiffs have not quantified their potential damage claims, we are unable at this time to provide an estimate of the range of possible loss relating to these proceedings or to determine the ultimate outcome of the securities class actions or their possible effect on our, or BGE's financial results.

Asbestos

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

Approximately 483 individuals who were never employees of BGE or Constellation Energy have pending claims each seeking several million dollars in compensatory and punitive damages. Cross-claims and third party claims brought by other defendants may also be filed against BGE and Constellation Energy in these actions. To date, most asbestos claims which have been resolved have been dismissed or resolved without any payment by BGE or Constellation Energy and a small minority of these cases have been resolved for amounts that were not material to our financial results.

Discovery begins in these cases once they are placed on the trial docket. At present, only a small number of our pending cases have reached the trial docket. Given the limited discovery, BGE and Constellation Energy do not know the specific facts that we believe are necessary for us to provide an estimate of the possible loss relating to these claims. The specific facts we do not know include:

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

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

Federal Energy Regulatory Commission Investigation

The Federal Energy Regulatory Commission (FERC) staff in the Office of Enforcement, Division of Investigations, is conducting an investigation of our virtual transactions and physical schedules in and around the New York ISO from September 2007 through December 2008. On August 29, 2011, the FERC staff notified us of its preliminary findings relating to our alleged violation of FERC's rules in connection with these activities. We continue to cooperate fully with the FERC investigation and, on October 28, 2011, we delivered to the FERC staff a response to their preliminary findings letter explaining why our conduct was lawful and refuting any allegation of wrongdoing. On January 30, 2012, FERC issued a Staff Notice of Alleged Violations, which reiterated the allegation that we violated FERC's rules relating to virtual transactions in the New York ISO and physical schedules between the New York ISO and PJM, Ontario and ISO-New England, and reiterated FERC's view of the impact of those transactions on our financial positions. We are continuing to cooperate with the FERC staff in bringing this matter to resolution. If FERC determines to proceed in this matter, FERC will issue an Order to Show Cause and a report from their staff outlining in detail their allegations. This Order, which may be issued within the next few months, would initiate a litigation process for resolving the matter and disclose FERC's view of penalties and disgorgement, which could be several hundred million dollars. However, we cannot currently predict how this matter will be resolved. While we believe we have meritorious defenses to the allegations, the ultimate outcome of the proceeding could have a material effect on our financial results.

Environmental Matters

Solid and Hazardous Waste

In 1999, the EPA proposed to add the 68th Street Dump in Baltimore, Maryland to the Superfund National Priorities List, which is its list of sites targeted for clean-up and enforcement, and sent a general notice letter to BGE and 19 other parties identifying them as potentially responsible parties at the site. In March 2004, we and other potentially responsible parties formed the 68th Street Coalition and entered into consent order negotiations with the EPA to investigate clean-up options for the site under the Superfund Alternative Sites Program. In May 2006, a settlement among the EPA and 19 of the potentially responsible parties, including BGE, with respect to investigation of the site became effective. The settlement requires the potentially responsible parties, over the course of several years, to identify contamination at the site and recommend clean-up options. BGE is indemnified by a wholly owned subsidiary of Constellation Energy for most of the costs related to this settlement and clean-up of the site. The potentially responsible parties submitted their investigation of the range of clean-up options in the first quarter of 2011. Although the investigation and options provided to the EPA are still subject to EPA review, we believe that the range of estimated clean-up costs to be allocated among all of the potentially responsible parties will be between approximately $50 million and $64 million depending on the clean-up option selected by the EPA. The EPA is expected to make a final selection of one of the alternatives in 2012. As the alternative to be selected by the EPA and the allocation of the clean-up costs among the potentially responsible parties is not yet known, we cannot provide an estimate of the range of our possible loss.

Air Quality

In January 2009, the EPA issued a notice of violation (NOV) to a subsidiary of Constellation Energy, as well as to the other owners and the operator of the Keystone coal-fired power plant in Shelocta, Pennsylvania. We hold a 20.99% interest in the Keystone plant. The NOV alleges that the plant performed various capital projects beginning in 1984 without complying with the new source review permitting requirements of the Clean Air Act. The EPA also contends that the alleged failure to comply with those requirements are continuing violations under the plant's air permits. The EPA could seek civil penalties under the Clean Air Act for the alleged violations.

The owners and operator of the Keystone plant have investigated the allegations and had a meeting with the EPA where they provided the EPA with both legal and factual documentation to support their position that no violations have occurred. Since that time, the EPA has not requested any further meeting or otherwise acted on the allegations. We believe there are meritorious defenses to the allegations contained in the NOV. Because there are significant facts in dispute and this matter is only in the NOV stage, at this time we cannot estimate the range of possible loss or predict whether a proceeding will be commenced.

Water Quality

In October 2007, a subsidiary of Constellation Energy entered into a consent decree with the Maryland Department of the Environment relating to groundwater contamination at a third party facility that was licensed to accept fly ash, a byproduct generated by our coal-fired plants. The consent decree requires the payment of a $1.0 million penalty, remediation of groundwater contamination resulting from the ash placement operations at the site, replacement of drinking water supplies in the vicinity of the site, and monitoring of groundwater conditions. Based on updated information regarding the remediation plan and the costs to cap the site, we have recorded a liability in our Consolidated Balance Sheets of approximately $22.7 million ($12.1 million of which was added in the fourth quarter of 2011), which includes the $1 million penalty and our estimate of probable costs to remediate contamination, replace drinking water supplies, monitor groundwater conditions, and otherwise comply with the consent decree. We have paid approximately $5.7 million of these costs as of December 31, 2011, resulting in a remaining liability at December 31, 2011 of $17.0 million.

Investment in CENG

On November 6, 2009, we completed the sale of a 49.99% membership interest in CENG to EDF. As a result of the sale, we now hold a 50.01% interest in CENG. As a 50.01% owner in CENG, we are subject to certain capital contribution requirements, which may be greater than the amount planned and, therefore, could have an adverse impact on our financial results.

In addition, if the fair value of our investment in CENG declines to a level below our carrying value and the decline is considered other-than-temporary, we may write down the investment to fair value, which would adversely affect our financial results. During 2011 and 2010, we recorded impairments of our investment in CENG. We discuss these impairment charges in more detail in *Note 2*.

We are also exposed to the same risks to which CENG is exposed. CENG owns and operates three nuclear generating facilities and is exposed to risks associated with operating these facilities and the risks of a nuclear accident.

Operating Risks

The operation of nuclear generating facilities involve routine risks, including,

- mechanical or structural problems,
- inadequacy or lapses in maintenance protocols,
- cost of storage, handling and disposal of nuclear materials, including the availability or unavailability of a permanent repository for spent nuclear fuel,
- regulatory actions, including shut down of units because of public safety concerns,
- limitations on the amounts and types of insurance coverage commercially available,
- uncertainties regarding both technological and financial aspects of decommissioning nuclear generating facilities,
- terrorist attacks, and
- environmental risks.

Nuclear Accidents

CENG is required to insure itself against public liability claims resulting from nuclear incidents to the full limit of public liability. This limit of liability consists of the maximum available commercial insurance of $375 million and mandatory participation in an industry-wide retrospective premium assessment program. The retrospective premium assessment is $117.5 million per reactor, per incident, increasing the total amount of insurance for public liability to approximately $12.6 billion. Under the retrospective assessment program, CENG can be assessed up to $587.5 million per incident at any commercial reactor in the country, payable at no more than $87.5 million per incident per year. In the event of a nuclear accident, the cost of property damage and other expenses incurred may exceed CENG’s insurance coverage. As a result, uninsured losses or the payment of retrospective insurance premiums could each have a significant adverse impact to CENG’s, and therefore, our financial results as a 50.01% owner in CENG. Each of Constellation Energy and EDF has guaranteed the obligations of CENG under these insurance programs in proportion to their respective membership interests.

Property and Accidental Outage Insurance

CENG’s nuclear plants are provided property and accidental outage insurance through Nuclear Electric Insurance Limited (NEIL). As the members-insured of NEIL through their ownership interest in CENG, Constellation Energy and EDF have assigned the loss benefits under the insurance to CENG’s nuclear plants, with CENG named as an additional insured party. In consideration for receiving the loss benefits, CENG pays the NEIL premiums.

If claims at nuclear plants insured by NEIL result in a shortfall of NEIL reserve funds, all policy holders could be assessed a retrospective premium, for which the combined Constellation Energy and EDF premium share for the current policy year could be as much as $94.6 million.

NEIL requires its members-insured to maintain an investment grade credit rating, or alternatively, provide NEIL with certain financial guarantees to ensure that it can meet its potential retrospective premium obligations. Should Constellation Energy experience a downgrade to its credit ratings to below investment grade, Constellation Energy would be required by NEIL to:

- deposit funds with NEIL in the full amount of its retrospective premium obligation,
- obtain a guarantee from an investment grade rated entity,
- post a letter of credit in the full amount of its maximum retrospective premium obligation from an investment grade rated financial institution, or
- obtain insurance to cover its retrospective premium obligation.

Non-Nuclear Property Insurance

Our conventional property insurance provides coverage of $1.0 billion per occurrence for Certified acts of terrorism as defined under the Terrorism Risk Insurance Extension Act of 2005 and the Terrorism Risk Insurance Program Reauthorization Act of 2007. Our conventional property insurance program also provides coverage for non-certified acts of terrorism up to an annual aggregate limit of $1.0 billion. If a terrorist act occurs at any of our facilities, it could have a significant adverse impact on our financial results.

13 Derivatives and Fair Value Measurements

Use of Derivative Instruments

Nature of Our Business and Associated Risks

Our business activities primarily include our Generation, NewEnergy, regulated electric and gas businesses. Our Generation and NewEnergy businesses include:

- the generation of electricity from our owned and contractually- controlled physical assets,
- the sale of power, gas, and other energy commodities to wholesale and retail customers, and
- risk management services and energy trading activities.

Our regulated electric and gas businesses engage in electricity and gas transmission and distribution activities in Central Maryland at prices set by the Maryland PSC that are generally designed to recover our costs, including purchased fuel and energy. Substantially all of our risk management activities involving derivatives occur outside our regulated businesses.

In carrying out our competitive business activities, we purchase and sell power, fuel, and other energy-related commodities in competitive markets. These activities expose us to significant risks, including market risk from price volatility for energy commodities and the credit risks of counterparties with which we enter into contracts. The sources of these risks include, but are not limited to, the following:

- the risks of unfavorable changes in power prices in the wholesale forward and spot markets in which we sell a portion of the power from our power generation facilities and purchase power to meet our load-serving requirements,
- the risk of unfavorable fuel price changes for the purchase of a portion of the fuel for our generation facilities under short-term contracts or on the spot market. Fuel prices can be volatile, and the price that can be obtained for power produced from such fuel may not change at the same rate as fuel costs.
- the risk that one or more counterparties may fail to perform under their obligations to make payments or deliver fuel or power,
- interest rate risk associated with variable-rate debt and the fair value of fixed-rate debt used to finance our operations; and
- foreign currency exchange rate risk associated with international investments and purchases of equipment and commodities in currencies other than U.S. dollars.

Objectives and Strategies for Using Derivatives

Risk Management Activities

To lower our exposure to the risk of unfavorable fluctuations in commodity prices, interest rates, and foreign currency rates, we routinely enter into derivative contracts, such as fixed-price forward physical purchase and sales contracts, futures, financial swaps, and option contracts traded in the over-the-counter markets or on exchanges, for hedging purposes. The objectives for entering into such hedging transactions primarily include:

- fixing the price for a portion of anticipated future electricity sales from our generation operations,
- fixing the price of a portion of anticipated fuel purchases for the operation of our power plants,
- fixing the price for a portion of anticipated energy purchases to supply our load-serving customers, and
- managing our exposure to interest rate risk and foreign currency exchange risks.

Non-Risk Management Activities

In addition to the use of derivatives for risk management purposes, we also enter into derivative contracts for trading purposes primarily for:

- optimizing the margin on surplus electricity generation and load positions and surplus fuel supply and demand positions,
- price discovery and verification, and
- deploying limited risk capital in an effort to generate returns.

Accounting for Derivative Instruments

The accounting requirements for derivatives require recognition of all qualifying derivative instruments on the balance sheet at fair value as either assets or liabilities.

Accounting Designation

We must evaluate new and existing transactions and agreements to determine whether they meet the definition of a derivative, for which there are several possible accounting treatments. The permissible accounting treatments include:

- normal purchase normal sale (NPNS),
- cash flow hedge,
- fair value hedge, and
- mark-to-market.

Mark-to-market is required as the default accounting treatment for all derivatives unless they qualify, and we specifically designate them, for one of the other accounting treatments. Derivatives designated for any of the elective accounting treatments must meet specific, restrictive criteria, both at the time of designation and on an ongoing basis.

We discuss our accounting policies for derivatives and hedging activities and their impacts on our financial statements in *Note 1*.

NPNS

We elect NPNS accounting for derivative contracts that provide for the purchase or sale of a physical commodity that will be delivered in quantities expected to be used or sold over a reasonable period in the normal course of business. Once we elect NPNS classification for a given contract, we cannot subsequently change the election and treat the contract as a derivative using mark-to-market or hedge accounting.

Cash Flow Hedging

We generally elect cash flow hedge accounting for most of the derivatives that we use to hedge market price risk for our physical energy delivery activities because hedge accounting more closely aligns the timing of earnings recognition and cash flows for the underlying business activities. Management monitors the potential impacts of commodity price changes and, where appropriate, may enter into or close out (via offsetting transactions) derivative transactions designated as cash flow hedges.

Commodity Cash Flow Hedges

We have designated fixed-price forward contracts as cash-flow hedges of forecasted sales of energy, fuel and other related commodities and forecasted purchases of fuel and energy for the years 2012 through 2017. We had net unrealized pre-tax losses on these cash-flow hedges recorded in “Accumulated other comprehensive loss” of $652.7 million at December 31, 2011 and $388.0 million at December 31, 2010.

We expect to reclassify $392.6 million of net pre-tax losses on cash-flow hedges from “Accumulated other comprehensive loss” into earnings during the next twelve months based on market prices at December 31, 2011. However, the actual amount reclassified into earnings could vary from the amounts recorded at December 31, 2011, due to future changes in market prices.

When we determine that a forecasted transaction originally designated as a hedged item has become probable of not occurring, we immediately reclassify net unrealized gains or losses associated with those hedges from “Accumulated other comprehensive loss” to earnings. We recognized in earnings the following pre-tax amounts on such contracts:

Year ended December 31,	**2011**	2010	2009
		(In millions)	
Pre-tax losses	**$(4.0)**	$(0.3)	$(241.0)

Interest Rate Swaps Designated as Cash Flow Hedges

We use interest rate swaps designated as cash flow hedges to manage our interest rate exposures associated with new debt issuances and to manage our exposure to fluctuations in interest rates on variable rate debt. The effective portion of gains and losses on these interest rate cash flow hedges, net of associated deferred income tax effects, is recorded in “Accumulated other comprehensive loss” in our Consolidated Statements of Shareholders’ Equity and Comprehensive Income (Loss). We reclassify gains and losses on the hedges from “Accumulated other comprehensive loss” into “Interest expense” in our Consolidated Statements of Income (Loss) during the periods in which the interest payments being hedged occur.

Accumulated other comprehensive loss includes net unrealized pre-tax gains on interest rate cash-flow hedges of prior debt issuances totaling $8.9 million at December 31, 2011 and $10.1 million at December 31, 2010. We expect to reclassify $0.1 million of pre-tax net losses on these cash-flow hedges from “Accumulated other comprehensive loss” into “Interest expense” during the next twelve months. We had no hedge ineffectiveness on these swaps.

During the third quarter of 2011, a subsidiary of Constellation Energy entered into forward-starting interest rate swap contracts to manage a portion of our interest rate exposure for anticipated long-term borrowings to finance our solar projects. The swaps have contract amounts that total $30.6 million with an average interest rate of 3.6% and expire in 2027. At December 31, 2011, the fair value of these swap contracts was an unrealized pre-tax loss of $3.6 million.

Fair Value Hedging

We elect fair value hedge accounting for a limited portion of our derivative contracts including certain interest rate swaps, certain forward contracts, and swaps associated with natural gas fuel in storage. The objectives for electing fair value hedging in these situations are to manage our exposure to changes in the fair value of our assets and liabilities, to optimize the mix of our fixed and floating-rate debt, and to hedge the value of our natural gas in storage.

Interest Rate Swaps Designated as Fair Value Hedges

We use interest rate swaps designated as fair value hedges to optimize the mix of fixed and floating-rate debt. We record any gains or losses on swaps that qualify for fair value hedge accounting treatment, as well as changes in the fair value of the debt being hedged, in “Interest expense.” We record changes in fair value of the swaps in “Derivative assets and liabilities” and changes in the fair value of the debt in “Long-term debt” in our Consolidated Balance Sheets. In addition, we record the difference between interest on hedged fixed-rate debt and floating-rate swaps in “Interest expense” in the periods that the swaps settle.

As of December 31, 2011, we have interest rate swaps qualifying as fair value hedges relating to $550 million of our fixed-rate debt maturing in 2015, and converted this notional amount of debt to floating-rate. The fair value of these hedges was an unrealized gain of $43.8 million at December 31, 2011.

As of December 31, 2010, we had interest rate swaps qualifying as fair value hedges relating to $400 million of our fixed-rate debt. The fair value of these hedges was an unrealized gain of $35.7 million at December 31, 2010.

We recorded the fair value of these hedges as an increase in our “Derivative assets” and an increase in our “Long-term debt.” We had no hedge ineffectiveness on these interest rate swaps.

In January 2011, we terminated $200 million of these interest rate swaps as a result of retiring all of our fixed-rate debt maturing in 2012 and received $13.8 million in cash.

During February 2011, we entered into interest rate swaps qualifying as fair value hedges related to $350 million of our fixed rate debt maturing in 2015, and converted this notional amount of debt to floating rate. We also entered into $150 million of interest rate swaps related to our fixed rate debt maturing in 2020 that do not qualify as fair value hedges, which are discussed under *Mark-to-Market* below.

Hedge Ineffectiveness

For all categories of derivative instruments designated in hedging relationships, we recorded in earnings the following pre-tax gains (losses) related to hedge ineffectiveness:

Year ended December 31,	**2011**	2010	2009
		(In millions)	
Cash-flow hedges	**$(132.4)**	$(91.3)	$11.3
Fair value hedges	**(0.7)**	—	23.9
Total	**$(133.1)**	$(91.3)	$35.2

The ineffectiveness in the table above excludes pre-tax gains of $5.8 million related to the change in our fair value hedges excluded from hedge ineffectiveness for the year ended December 31, 2011. We did not have any gains excluded from the above table in 2010 and 2009. We did not recognize any gain or loss related to the change in our fair value hedges excluded from hedge ineffectiveness during the years ended December 31, 2011, 2010, and 2009.

Mark-to-Market

We generally apply mark-to-market accounting for risk management and trading activities for which changes in fair value more closely reflect the economic performance of the underlying business activity. However, we also use mark-to-market accounting for derivatives related to the following activities:

- our competitive retail gas customer supply activities, which are managed using economic hedges that we have not designated as cash-flow hedges in order to match the timing of recognition of the earnings impacts of those activities to the greatest extent permissible,
- economic hedges of activities that require accrual accounting for which the related hedge requires mark-to-market accounting, and
- during February 2011, we entered into interest rate swaps related to $150 million of our fixed rate debt maturing in 2020, and converted this notional amount of debt to floating rate. However, these interest rate swaps do not qualify as fair value hedges and will be marked to market through earnings.

Origination Gains

We may record origination gains associated with commodity derivatives subject to mark-to-market accounting. Origination gains represent the initial fair value of certain structured transactions that our wholesale marketing, risk management, and trading operation executes to meet the risk management needs of our customers. Historically, transactions that result in origination gains have been unique and resulted in individually significant gains from a single transaction. We generally recognize origination gains when we are able to obtain observable market data to validate that the initial fair value of the contract differs from the contract price. We have recorded a $14.8 million pre-tax origination gain related to one transaction in 2011. We recorded no origination gains during 2010 or 2009.

Termination or Restructuring of Commodity Derivative Contracts

We may terminate or restructure commodity derivative contracts in exchange for upfront cash payments and a reduction or cancellation of future performance obligations. The termination or restructuring of contracts allows us to lower our exposure to performance risk under these contracts. We had no such transactions in 2011, 2010 and 2009.

Quantitative Information About Derivatives and Hedging Activities

Background

Effective January 1, 2009, we adopted an accounting standard that addresses disclosures about derivative instruments and hedging activities. This standard does not change the accounting for derivatives; rather, it requires expanded disclosure about derivative instruments and hedging activities regarding:

- the ways in which an entity uses derivatives,
- the accounting for derivatives and hedging activities, and
- the impact that derivatives have (or could have) on an entity’s financial position, financial performance, and cash flows.

Balance Sheet Tables

We present our derivative assets and liabilities in our Consolidated Balance Sheets on a net basis, including cash collateral, whenever we have a legally enforceable master netting agreement with a counterparty to a derivative contract. We use master netting agreements whenever possible to manage and substantially reduce our potential counterparty credit risk. The net presentation in our Consolidated Balance Sheets reflects our actual credit exposure after giving effect to the beneficial effects of these agreements and cash collateral, and our credit risk is reduced further by other forms of collateral.

The following tables provide information about the risks we manage using derivatives. These tables only include derivatives and do not reflect the price risks we are hedging that arise from physical assets or nonderivative accrual contracts within our Generation and NewEnergy businesses.

As discussed more fully following the table, we present this information by disaggregating our net derivative assets and liabilities into gross components on a contract-by-contract basis before giving effect to the risk-reducing benefits of master netting arrangements and collateral. As a result, we must present each individual contract as an "asset value" if it is in the money or a "liability value" if it is out of the money, regardless of whether the individual contracts offset market or credit risks of other contracts in full or in part. Therefore, the gross amounts in these tables do not reflect our actual economic or credit risk associated with derivatives. This gross presentation is intended only to show separately the various derivative contract types we use, such as commodities, interest rate, and foreign exchange.

In order to identify how our derivatives impact our financial position, at the bottom of the table we provide a reconciliation of the gross fair value components to the net fair value amounts as presented in the *Fair Value Measurements* section of this note and our Consolidated Balance Sheets.

The gross asset and liability values in the tables below are segregated between those derivatives designated in qualifying hedge accounting relationships and those not designated in hedge accounting relationships. Derivatives not designated in hedging relationships include our NewEnergy retail power and gas customer supply operation, economic hedges of accrual activities, and risk management and trading activities which we have substantially curtailed as part of our effort to reduce risk in our business. We use the end of period accounting designation to determine the classification for each derivative position.

As of December 31, 2011	Derivatives Designated as Hedging Instruments for Accounting Purposes		Derivatives Not Designated As Hedging Instruments for Accounting Purposes		All Derivatives Combined	
Contract type	Asset Values (3)	Liability Values (4)	Asset Values (3)	Liability Values (4)	Asset Values (3)	Liability Values (4)
			(In millions)			
Power contracts	$1,617.2	$(1,686.9)	$4,785.8	$ (5,105.9)	$ 6,403.0	$ (6,792.8)
Gas contracts	1,624.5	(2,108.4)	4,842.8	(4,858.1)	6,467.3	(6,966.5)
Coal contracts	34.0	(36.0)	73.0	(66.3)	107.0	(102.3)
Other commodity contracts (1)	—	—	153.8	(144.2)	153.8	(144.2)
Interest rate contracts	43.9	(3.6)	55.1	(49.0)	99.0	(52.6)
Foreign exchange contracts	—	—	10.5	(2.8)	10.5	(2.8)
Equity contracts	—	—	0.2	—	0.2	—
Total gross fair values	$3,319.6	$(3,834.9)	$9,921.2	$(10,226.3)	$ 13,240.8	$(14,061.2)
Netting arrangements (5)					(12,989.5)	12,989.5
Cash collateral					(167.2)	23.8
Net fair values					$ 84.1	$ (1,047.9)
Net fair value by balance sheet line item:						
Accounts receivable (2)					$ (533.1)	
Derivative assets—current					357.9	
Derivative assets—noncurrent					259.3	
Derivative liabilities—current						(779.5)
Derivative liabilities—noncurrent						(268.4)
Total Derivatives					$ 84.1	$ (1,047.9)

(1) Other commodity contracts include oil, freight, emission allowances, renewable energy credits, and weather contracts.

(2) Represents the unrealized fair value of exchange traded derivatives, exclusive of cash margin posted.

(3) Represents in-the-money contracts without regard to potentially offsetting out-of-the-money contracts under master netting agreements.

(4) Represents out-of-the-money contracts without regard to potentially offsetting in-the-money contracts under master netting agreements.

(5) Represents the effect of legally enforceable master netting agreements.

As of December 31, 2010 Contract type	Derivatives Designated as Hedging Instruments for Accounting Purposes Asset Values (3)	 Liability Values (4)	Derivatives Not Designated As Hedging Instruments for Accounting Purposes Asset Values (3)	 Liability Values (4)	All Derivatives Combined Asset Values (3)	 Liability Values (4)
			(In millions)			
Power contracts	$1,167.9	$(1,362.8)	$ 6,795.0	$ (7,166.5)	$ 7,962.9	$ (8,529.3)
Gas contracts	1,902.3	(1,832.8)	3,390.1	(3,155.3)	5,292.4	(4,988.1)
Coal contracts	97.0	(48.6)	266.0	(259.7)	363.0	(308.3)
Other commodity contracts (1)	—	—	61.4	(61.6)	61.4	(61.6)
Interest rate contracts	35.7	—	34.4	(35.7)	70.1	(35.7)
Foreign exchange contracts	—	—	11.0	(8.4)	11.0	(8.4)
Total gross fair values	$3,202.9	$(3,244.2)	$10,557.9	$(10,687.2)	$ 13,760.8	$(13,931.4)
Netting arrangements (5)					(12,955.5)	12,955.5
Cash collateral					(28.4)	0.6
Net fair values					$ 776.9	$ (975.3)
Net fair value by balance sheet line item:						
Accounts receivable (2)					$ (16.4)	
Derivative assets—current					534.4	
Derivative assets—noncurrent					258.9	
Derivative liabilities—current						(622.3)
Derivative liabilities—noncurrent						(353.0)
Total Derivatives					$ 776.9	$ (975.3)

(1) *Other commodity contracts include oil, freight, emission allowances, and weather contracts.*
(2) *Represents the unrealized fair value of exchange traded derivatives, exclusive of cash margin posted.*
(3) *Represents in-the-money contracts without regard to potentially offsetting out-of-the-money contracts under master netting agreements.*
(4) *Represents out-of-the-money contracts without regard to potentially offsetting in-the-money contracts under master netting agreements.*
(5) *Represents the effect of legally enforceable master netting agreements.*

The magnitude of and changes in the gross derivatives components in these tables do not indicate changes in the level of derivative activities, the level of market risk, or the level of credit risk. The primary factors affecting the magnitude of the gross amounts in the table are changes in commodity prices and the total number of contracts. If commodity prices change, the gross amounts could increase, even if the level of contracts stays the same, because separate presentation is required for contracts that are in the money from those that are out of the money. As a result, the gross amounts of even fully hedged positions could increase if prices change. Additionally, if the number of contracts increases, the gross amounts also could increase. Thus, the execution of new contracts to reduce economic risk could actually increase the gross amounts in the table because of the requirement to present the gross value of each individual contract separately.

The primary purpose of these tables is to disaggregate the risks being managed using derivatives. In order to achieve this objective, we prepare this table by separating each individual derivative contract that is in the money from each contract that is out of the money and present such amounts on a gross basis, even for offsetting contracts that have identical quantities for the same commodity, location, and delivery period. We must also present these components excluding the substantive credit-risk reducing effects of master netting agreements and collateral. As a result, the gross "asset" and "liability" amounts for each contract type far exceed our actual economic exposure to commodity price risk and credit risk. Our actual economic exposure consists of the net derivative position combined with our nonderivative accrual contracts, such as those for load-serving, and our physical assets, such as our power plants. Our actual derivative credit risk exposure after master netting agreements and cash collateral is reflected in the net fair value amounts shown at the bottom of the table above. Our total economic and credit exposures, including derivatives, are managed in a comprehensive risk framework that includes risk measures such as economic value at risk, stress testing, and maximum potential credit exposure.

Gain and (Loss) Tables

The tables below summarize the gain and loss impacts of our derivative instruments segregated into the following categories:

- cash flow hedges,
- fair value hedges, and
- mark-to-market derivatives.

The tables only include this information for derivatives and do not reflect the related gains or losses that arise from generation and generation-related assets, nonderivative accrual contracts, or NPNS contracts within our Generation and NewEnergy businesses, other than fair value hedges, for which we separately show the gain or loss on the hedged asset or liability. As a result, for mark-to-market and cash-flow hedge derivatives, these tables only reflect the impact of derivatives themselves and therefore do not necessarily include all of the income statement impacts of the transactions for which derivatives are used to manage risk. For a more complete discussion of how derivatives affect our financial performance, see our accounting policy for *Revenues*, *Fuel and Purchased Energy Expenses*, and *Derivatives and Hedging Activities* in *Note 1*.

The following tables present gains and losses on derivatives designated as cash flow hedges. As discussed more fully in our accounting policy, we record the effective portion of unrealized gains and losses on cash flow hedges in Accumulated Other Comprehensive Loss until the hedged forecasted transaction affects earnings. We record the ineffective portion of gains and losses on cash flow hedges in earnings as they occur. When the hedged forecasted transaction settles and is recorded in earnings, we reclassify the related amounts from Accumulated Other Comprehensive Loss into earnings, with the result that the combination of revenue or expense from the forecasted transaction and gain or loss from the hedge are recognized in earnings at a total amount equal to the hedged price. Accordingly, the amount of derivative gains and losses recorded in Accumulated Other Comprehensive Loss and reclassified from Accumulated Other Comprehensive Loss into earnings does not reflect the total economics of the hedged forecasted transactions. The total impact of our forecasted transactions and related hedges is reflected in our Consolidated Statements of Income (Loss).

Cash Flow Hedges

								Year Ended December 31,		
	Gain (Loss) Recorded in AOCI			Statement of Income (Loss) Line Item	Gain (Loss) Reclassified from AOCI into Earnings			Ineffectiveness Gain (Loss) Recorded in Earnings		
Contract type:	2011	2010	2009		2011	2010	2009	2011	2010	2009
				(In millions)						
Hedges of forecasted sales:				Nonregulated revenues						
Power contracts	$ 162.3	$ 144.5	$ 362.5		$ 19.2	$ (165.8)	$ (180.6)	$ 70.9	$ 8.9	$ 77.5
Gas contracts	63.5	(59.1)	(65.1)		198.5	90.8	(67.3)	(49.6)	(0.3)	6.3
Coal contracts	—	—	10.0		—	—	(229.9)	—	—	—
Other commodity contracts (1)	—	—	6.8		—	(0.7)	(0.4)	—	—	(6.2)
Interest rate contracts	—	—	(0.3)		—	—	(0.3)	—	—	—
Foreign exchange contracts	—	—	2.5		—	(1.0)	(1.1)	—	—	—
Total gains (losses)	$ 225.8	$ 85.4	$ 316.4	Total included in nonregulated revenues	$ 217.7	$ (76.7)	$ (479.6)	$ 21.3	$ 8.6	$ 77.6
Hedges of forecasted purchases:				Fuel and purchased energy expense						
Power contracts	$(295.5)	$(377.4)	$(1,056.0)		$(476.7)	$(1,036.1)	$(1,905.3)	$ (52.0)	$(40.7)	$(42.2)
Gas contracts	(471.6)	(141.5)	103.7		(51.8)	216.5	165.8	(102.5)	(64.3)	(15.2)
Coal contracts	(11.8)	65.9	(77.7)		22.4	(34.6)	(187.6)	0.8	4.9	(8.9)
Other commodity contracts (2)	—	(0.2)	(12.3)		—	(0.3)	8.2	—	0.2	—
Foreign exchange contracts	—	—	—		—	—	—	—	—	—
Total losses	$(778.9)	$(453.2)	$(1,042.3)	Total included in fuel and purchased energy expense	$(506.1)	$ (854.5)	$(1,918.9)	$(153.7)	$(99.9)	$(66.3)
Hedges of interest rates:				Interest expense						
Interest rate contracts	(3.6)	—	—		1.2	4.3	0.6	—	—	—
Total (losses) gains	$ (3.6)	$ —	$ —	Total included in interest expense	$ 1.2	$ 4.3	$ 0.6	$ —	$ —	$ —
Grand total (losses) gains	$(556.7)	$(367.8)	$ (725.9)		$(287.2)	$ (926.9)	$(2,397.9)	$(132.4)	$(91.3)	$ 11.3

(1) Other commodity sale contracts include oil and freight contracts.

(2) Other commodity purchase contracts include freight and emission allowances.

The following table presents gains and losses on derivatives designated as fair value hedges and, separately, the gains and losses on the hedged item. As discussed earlier, we record the unrealized gains and losses on fair value hedges as well as changes in the fair value of the hedged asset or liability in earnings as they occur. The difference between these amounts represents hedge ineffectiveness.

Fair Value Hedges

					Year Ended December 31,		
		Amount of Gain (Loss) Recognized in Income on Derivative			Amount of Gain (Loss) Recognized in Income on Hedged Item		
Contract type:	Statement of Income (Loss) Line Item	2011	2010	2009	2011	2010	2009
				(In millions)			
Gas contracts	Nonregulated revenues	$23.4	$ —	$40.6	$(15.9)	$ —	$(16.7)
Interest rate contracts	Interest expense	32.9	18.0	(0.1)	(32.8)	(15.6)	0.7
Total gains (losses)		$56.3	$18.0	$40.5	$(48.7)	$(15.6)	$(16.0)

The following table presents gains and losses on mark-to-market derivatives, contracts that have not been designated as hedges for accounting purposes. As discussed more fully in *Note 1*, we record the unrealized gains and losses on mark-to-market derivatives in earnings as they occur. While we use mark-to-market accounting for risk management and trading activities because changes in fair value more closely reflect the economic performance of the activity, we also use mark-to-market accounting for certain derivatives related to portions of our physical energy delivery activities. Accordingly, the total amount of gains and losses from mark-to-market derivatives does not necessarily reflect the total economics of related transactions.

Mark-to-Market Derivatives		*Year Ended December 31,* Amount of Gain (Loss) Recorded in Income on Derivative		
Contract type:	Statement of Income (Loss) Line Item	2011	2010	2009
			(In millions)	
Commodity contracts:				
Power contracts	Nonregulated revenues	$ (51.4)	$(26.2)	$ 250.9
Gas contracts	Nonregulated revenues	(224.3)	41.4	(360.0)
Coal contracts	Nonregulated revenues	(9.2)	13.3	14.0
Other commodity contracts (1)	Nonregulated revenues	(4.4)	(15.4)	(11.7)
Coal contracts	Fuel and purchased energy expense	—	—	(109.8)
Interest rate contracts	Nonregulated revenues	1.6	(2.3)	(27.2)
Interest rate contracts	Interest expense	5.2	—	—
Foreign exchange contracts	Nonregulated revenues	0.4	(1.2)	7.6
Equity contracts	Nonregulated revenues	(0.4)	—	—
Total gains (losses)		$(282.5)	$ 9.6	$(236.2)

(1) Other commodity contracts include oil, freight, weather, renewable energy credits, and emission allowances.

In computing the amounts of derivative gains and losses in the above tables, we include the changes in fair values of derivative contracts up to the date of maturity or settlement of each contract. This approach facilitates a comparable presentation for both financial and physical derivative contracts. In addition, for cash flow hedges we include the impact of intra-quarter transactions (i.e., those that arise and settle within the same quarter) in both gains and losses recognized in Accumulated Other Comprehensive Loss and amounts reclassified from Accumulated Other Comprehensive Loss into earnings.

Volume of Derivative Activity

The volume of our derivatives activity is directly related to the fundamental nature and scope of our business and the risks we manage. We own or control electric generating facilities, which exposes us to both power and fuel price risk; we serve electric and gas wholesale and retail customers within our NewEnergy business, which exposes us to electricity and natural gas price risk; and we provide risk management services and engage in trading activities, which can expose us to a variety of commodity price risks. In order to manage the risks associated with these activities, we are required to be an active participant in the energy markets, and we routinely employ derivative instruments to conduct our business.

Derivative instruments provide an efficient and effective way to conduct our business and to manage the associated risks. As such, we use derivatives in the following ways:

- We manage our generating resources and NewEnergy business based upon established policies and limits, and we use derivatives to establish a portion of our hedges and to adjust the level of our hedges from time to time.
- We engage in trading activities which enable us to execute hedging transactions in a cost-effective manner. We manage those activities based upon various risk measures, including position limits, economic value at risk (EVaR) and value at risk (VaR), and we use derivatives to establish and maintain those activities within the prescribed limits.
- We also use derivatives to execute, control, and reduce the overall level of our trading positions and risk as well as to manage a portion of our interest rate risk associated with debt and our foreign currency risk from non-dollar denominated transactions.

The following tables present information designed to provide insight into the overall volume of our derivatives usage. However, the volumes presented in these tables should only be used as an indication of the extent of our derivatives usage and the risks they are intended to manage and are subject to a number of limitations as follows:

- The volume information is not a complete representation of our market price risk because it only includes derivative contracts. Accordingly, these tables do not present a complete picture of our overall net economic exposure, and should not be interpreted as an indication of open or unhedged commodity positions, because the use of derivatives is only one of the means by which we engage in and manage the risks of our business. For example, the table does not include power or fuel quantities and risks arising from our physical assets, non-derivative contracts, and forecasted transactions that we manage using derivatives; a portion of these volumes reduces those risks.

- The tables also do not include volumes of commodities under nonderivative contracts that we use to serve customers or manage our risks. Our actual net economic exposure from our generating facilities and NewEnergy activities is reduced by derivatives, and the exposure from our trading activities is managed and controlled through the risk measures discussed above. Therefore, the information in the tables below is only an indication of that portion of our business that we manage through derivatives and serves primarily to identify the extent of our derivatives activities and the types of risks that they are intended to manage.
- We have computed the derivative volumes for commodities by aggregating the absolute value of net positions within commodities for each year. This provides an indication of the level of derivatives activity, but it does not indicate either the direction of our position (long or short), or the overall size of our position. We believe this presentation gives an appropriate indication of the level of derivatives activity without unnecessarily revealing the size and direction of our derivatives positions. The disclosure of such information could limit the effectiveness and profitability of our business activities.
- The volume information for commodity derivatives represents "delta equivalent" quantities, not gross notional amounts. We believe that the delta equivalent quantity is the most relevant measure of the volume associated with commodity derivatives. The delta-equivalent quantity represents a risk-adjusted notional quantity for each contract that takes into account the probability that an option will be exercised. For interest rate contracts and foreign currency contracts we have presented the notional amounts of such contracts in the table below.

The following tables present the volume of our derivative activities as of December 31, 2011 and 2010, shown by contractual settlement year.

Quantities (1) Under Derivative Contracts Contract Type (Unit)	2012	2013	2014	2015	*As of December 31, 2011* 2016	Thereafter	Total
				(In millions)			
Power (MWH)	20.8	13.0	0.9	0.4	1.7	0.4	37.2
Gas (mmBTU)	263.6	47.7	49.4	18.4	1.8	1.8	382.7
Coal (Tons)	0.8	0.7	—	—	—	—	1.5
Oil (BBL)	0.1	0.3	0.1	—	—	—	0.5
Emission Allowances (Tons)	0.1	0.1	—	—	—	—	0.2
Renewable Energy Credits (Number of credits)	0.3	0.3	0.3	0.3	0.3	0.2	1.7
Equity contracts (Number of shares)	—	—	0.1	0.1	—	—	0.2
Interest Rate Contracts	$ 6.7	$515.2	$173.0	$800.0	$387.0	$ 255.6	$2,137.5
Foreign Exchange Rate Contracts	$ 44.1	$ 8.0	$ 16.8	$ 15.5	$ —	$ —	$ 84.4

Quantities (1) Under Derivative Contracts Contract Type (Unit)	2011	2012	2013	2014	*As of December 31, 2010* 2015	Thereafter	Total
				(In millions)			
Power (MWH)	21.2	—	3.8	4.2	2.3	0.2	31.7
Gas (mmBTU)	175.3	90.1	80.2	64.7	24.1	—	434.4
Coal (Tons)	4.4	2.5	0.1	—	—	—	7.0
Oil (BBL)	0.2	0.1	0.1	—	—	—	0.4
Emission Allowances (Tons)	1.5	—	—	—	—	—	1.5
Renewable Energy Credits (Number of credits)	0.4	0.3	0.3	0.3	0.3	0.7	2.3
Interest Rate Contracts	$639.4	$490.7	$941.8	$405.0	$460.0	$ 175.0	$3,111.9
Foreign Exchange Rate Contracts	$ 48.7	$ 8.7	$ 16.8	$ 16.8	$ 15.5	$ —	$ 106.5

(1) Amounts in the table are only intended to provide an indication of the level of derivatives activity and should not be interpreted as a measure of any derivative position or overall economic exposure to market risk. Quantities are expressed as "delta equivalents" on an absolute value basis by contract type by year. Additionally, quantities relate only to derivatives and do not include potentially offsetting quantities associated with physical assets and nonderivative accrual contracts.

In addition to the commodities in the tables above, we also hold derivative instruments related to weather that are insignificant relative to the overall level of our derivative activity.

Credit-Risk Related Contingent Features

Certain of our derivative instruments contain provisions that would require additional collateral upon a credit-related event such as an adequate assurance provision or a credit rating decrease in the senior unsecured debt of Constellation Energy. The amount of collateral we could be required to post would be determined by the fair value of contracts containing such provisions that represent a net liability, after offset for the fair value of any asset contracts with the same counterparty under master netting agreements and any other collateral already posted. This collateral amount is a component of, and is not in addition to, the total collateral we could be required to post for all contracts upon a credit rating decrease.

The following tables present information related to these derivatives at December 31, 2011 and 2010

We present the gross fair value of derivatives in a net liability position that have credit-risk-related contingent features in the first column in the table below. This gross fair value amount represents only the out-of-the-money contracts containing such features that are not fully collateralized by cash on a stand-alone basis. Thus, this amount does not reflect the offsetting fair value of in-the-money contracts under legally-binding master netting agreements with the same counterparty, as shown in the second column in the table. These in-the-money contracts would offset the amount of any gross liability that could be required to be collateralized, and as a result, the actual potential collateral requirements would be based upon the net fair value of derivatives containing such features, not the gross amount. The amount of any possible contingent collateral for such contracts in the event of a downgrade would be further reduced to the extent that we have already posted collateral related to the net liability.

Because the amount of any contingent collateral obligation would be based on the net fair value of all derivative contracts under each master netting agreement, we believe that the "net fair value of derivative contracts containing this feature" as shown in the tables below is the most relevant measure of derivatives in a net liability position with credit-risk-related contingent features. This amount reflects the actual net liability upon which existing collateral postings are computed and upon which any additional contingent collateral obligation would be based.

Credit-Risk Related Contingent Feature			As of December 31, 2011	
Gross Fair Value of Derivative Contracts Containing This Feature (1)	Offsetting Fair Value of In-the-Money Contracts Under Master Netting Agreements (2)	Net Fair Value of Derivative Contracts Containing This Feature (3)	Amount of Posted Collateral (4)	Contingent Collateral Obligation (5)
		(In billions)		
$3.3	$ (2.4)	$ 0.9	$ 0.6	$ 0.2

Credit-Risk Related Contingent Feature			As of December 31, 2010	
Gross Fair Value of Derivative Contracts Containing This Feature (1)	Offsetting Fair Value of In-the-Money Contracts Under Master Netting Agreements (2)	Net Fair Value of Derivative Contracts Containing This Feature (3)	Amount of Posted Collateral (4)	Contingent Collateral Obligation (5)
		(In billions)		
$4.6	$(3.7)	$0.9	$0.7	$0.1

(1) Amount represents the gross fair value of out-of-the-money derivative contracts containing credit-risk-related contingent features that are not fully collateralized by posted cash collateral on an individual, contract-by-contract basis ignoring the effects of master netting agreements.

(2) Amount represents the offsetting fair value of in-the-money derivative contracts under legally-enforceable master netting agreements with the same counterparty, which reduces the amount of any liability for which we potentially could be required to post collateral.

(3) Amount represents the net fair value of out-of-the-money derivative contracts containing credit-risk related contingent features after considering the mitigating effects of offsetting positions under master netting arrangements and reflects the actual net liability upon which any potential contingent collateral obligations would be based.

(4) Amount includes cash collateral posted of $23.8 million and letters of credit of $563.6 million at December 31, 2011 and cash collateral posted of $0.6 million and letters of credit of $656.9 million at December 31, 2010.

(5) Amounts represent the additional collateral that we could be required to post with counterparties, including both cash collateral and letters of credit, in the event of a credit downgrade to below investment grade after giving consideration to offsetting derivative and non-derivative positions under master netting agreements.

Concentrations of Derivative-Related Credit Risk

We discuss our concentrations of credit risk, including derivative-related positions, in *Note 1*. At December 31, 2011, we had credit exposure to two counterparties, both large investment grade power cooperatives, equal to 29% of our total credit exposure.

Fair Value Measurements

We determine the fair value of our assets and liabilities using unadjusted quoted prices in active markets (Level 1) or pricing inputs that are observable (Level 2) whenever that information is available. We use unobservable inputs (Level 3) to estimate fair value only when relevant observable inputs are not available.

We classify assets and liabilities within the fair value hierarchy based on the lowest level of input that is significant to the fair value measurement of each individual asset and liability taken as a whole. We determine fair value for assets and liabilities classified as Level 1 by multiplying the market price by the quantity of the asset or liability. We primarily determine fair value measurements classified as Level 2 or Level 3 using the income valuation approach, which involves discounting estimated cash flows using assumptions that market participants would use in pricing the asset or liability.

We present all derivatives recorded at fair value net with the associated fair value cash collateral. This presentation of the net position reflects our credit exposure for our on-balance sheet positions but excludes the impact of any off-balance sheet positions and collateral. Examples of off-balance sheet positions and collateral include in-the-money accrual contracts for which the right of offset exists in the event of default and letters of credit. We discuss our letters of credit in more detail in *Note 8*.

Recurring Measurements

Our assets and liabilities measured at fair value on a recurring basis consist of the following (immaterial for BGEs assets and liabilities):

	As of December 31, 2011	
	Assets	Liabilities
	(In millions)	
Cash equivalents	$ 344.2	$ —
Debt and equity securities	39.8	—
Derivative instruments:		
Classified as derivative assets and liabilities:		
Current	357.9	(779.5)
Noncurrent	259.3	(268.4)
Total classified as derivative assets and liabilities	617.2	(1,047.9)
Classified as accounts receivable (1)	(533.1)	—
Total derivative instruments	84.1	(1,047.9)
Total recurring fair value measurements	$ 468.1	$(1,047.9)

(1) Represents the unrealized fair value of exchange traded derivatives, exclusive of cash margin posted.

	As of December 31, 2010	
	Assets	Liabilities
	(In millions)	
Cash equivalents	$1,545.4	$ —
Debt and equity securities	47.8	—
Derivative instruments:		
Classified as derivative assets and liabilities:		
Current	534.4	(622.3)
Noncurrent	258.9	(353.0)
Total classified as derivative assets and liabilities	793.3	(975.3)
Classified as accounts receivable (1)	(16.4)	—
Total derivative instruments	776.9	(975.3)
Total recurring fair value measurements	$2,370.1	$(975.3)

(1) *Represents the unrealized fair value of exchange traded derivatives, exclusive of cash margin posted.*

Cash equivalents represent money market funds which are included in “Cash and cash equivalents” in the Consolidated Balance Sheets. Debt securities primarily represent available-for-sale investments in private companies included in “Other assets” in the Consolidated Balance Sheets. Equity securities primarily represent mutual fund investments which are included in “Other assets” in the Consolidated Balance Sheets. Derivative instruments represent unrealized amounts related to all derivatives. We classify exchange- listed derivatives as part of “Accounts Receivable” in our Consolidated Balance Sheets. We classify the remainder of our derivatives as “Derivative assets” or “Derivative liabilities” in our Consolidated Balance Sheets.

The tables below set forth by level within the fair value hierarchy the gross components of the Company’s assets and liabilities that were measured at fair value on a recurring basis as of December 31, 2011 and 2010. We disaggregate our net derivative assets and liabilities by separating each individual derivative contract that is in-the-money from each contract that is out-of-the-money regardless of master netting agreements and collateral. As a result, the gross “asset” and “liability” amounts in each of the three fair value levels far exceed our actual economic exposure to commodity price risk and credit risk. The objective of these tables is to provide information about how each individual derivative contract is valued within the fair value hierarchy, regardless of whether a particular contract is eligible for netting against other contracts or whether it has been collateralized. Therefore, these gross balances are intended solely to provide information on sources of inputs to fair value and proportions of fair value involving objective versus subjective valuations and do not represent either our actual credit exposure or net economic exposure.

At December 31, 2011	Level 1	Level 2	Level 3	Netting and Cash Collateral (1)	Total Net Fair Value
			(In millions)		
Cash equivalents	$ 344.2	$ —	$ —	$ —	$ 344.2
Debt and equity securities	30.5	—	9.3	—	39.8
Derivative assets:					
Power contracts	—	5,835.2	567.8		
Gas contracts	430.5	5,371.2	665.6		
Coal contracts	—	106.8	0.2		
Other commodity contracts	2.0	35.2	116.6		
Interest rate contracts	48.2	50.8	—		
Foreign exchange contracts	—	10.5	—		
Equity contracts	—	—	0.2		
Total derivative assets	480.7	11,409.7	1,350.4	(13,156.7)	84.1
Derivative liabilities:					
Power contracts	—	(6,175.0)	(617.8)		
Gas contracts	(450.4)	(6,046.9)	(470.3)		
Coal contracts	—	(101.6)	(0.7)		
Other commodity contracts	(2.2)	(25.2)	(116.8)		
Interest rate contracts	(47.9)	—	(3.6)		
Foreign exchange contracts	—	(2.8)	—		
Total derivative liabilities	(500.5)	(12,351.5)	(1,209.2)	13,013.3	(1,047.9)
Net derivative position	(19.8)	(941.8)	141.2	(143.4)	(963.8)
Total	$ 354.9	$ (941.8)	$ 150.5	$ (143.4)	$ (579.8)

(1) *We present our derivative assets and liabilities in our Consolidated Balance Sheets on a net basis. We net derivative assets and liabilities, including cash collateral, when a legally enforceable master netting agreement exists between us and the counterparty to a derivative contract. At December 31, 2011, we included $167.2 million of cash collateral held and $23.8 million of cash collateral posted (excluding margin posted on exchange traded derivatives) in netting amounts in the above table.*

At December 31, 2010	Level 1	Level 2	Level 3	Netting and Cash Collateral (1)	Total Net Fair Value
			(In millions)		
Cash equivalents	$1,545.4	$ —	$ —	$ —	$1,545.4
Debt and equity securities	43.7	—	4.1	—	47.8
Derivative assets:					
Power contracts	—	7,509.6	453.3		
Gas contracts	63.9	5,113.3	115.2		
Coal contracts	—	355.6	7.4		
Other commodity contracts	6.6	54.8	—		
Interest rate contracts	33.1	37.0	—		
Foreign exchange contracts	—	11.0	—		
Total derivative assets	103.6	13,081.3	575.9	(12,983.9)	776.9
Derivative liabilities:					
Power contracts	—	(7,758.2)	(771.1)		
Gas contracts	(72.7)	(4,910.3)	(5.1)		
Coal contracts	—	(307.4)	(0.9)		
Other commodity contracts	(7.1)	(54.5)	—		
Interest rate contracts	(35.7)	—	—		
Foreign exchange contracts	—	(8.4)	—		
Total derivative liabilities	(115.5)	(13,038.8)	(777.1)	12,956.1	(975.3)
Net derivative position	(11.9)	42.5	(201.2)	(27.8)	(198.4)
Total	$1,577.2	$ 42.5	$(197.1)	$ (27.8)	$1,394.8

(1) We present our derivative assets and liabilities in our Consolidated Balance Sheets on a net basis. We net derivative assets and liabilities, including cash collateral, when a legally enforceable master netting agreement exists between us and the counterparty to a derivative contract. At December 31, 2010, we included $28.4 million of cash collateral held and $0.6 million of cash collateral posted (excluding margin posted on exchange traded derivatives) in netting amounts in the above table.

The factors that cause changes in the gross components of the derivative amounts in the tables above are unrelated to the existence or level of actual market or credit risk from our operations. We describe the primary factors that change the gross components below.

Increases and decreases in the gross components presented in each of the levels in these tables do not indicate changes in the level of derivative activities. Rather, the primary factors affecting the gross amounts are commodity prices and the total number of contracts. If commodity prices change, the gross amounts could increase, even if the level of contracts stays the same, because separate presentation is required for contracts that are in the money from those that are out of the money. As a result, even fully hedged positions could exhibit increases in the gross amounts if prices change. Additionally, if the number of contracts increases, the gross amounts also could increase. Thus, the execution of new contracts to reduce economic risk could actually increase the gross amounts in the table because of the required separation of contracts discussed above.

Cash equivalents consist of exchange-traded money market funds, which are valued by multiplying unadjusted quoted prices in active markets by the quantity of the asset and are classified within Level 1.

Debt securities consist of Series A Preferred Stock in two privately owned companies, which are valued based on the purchase price of the security and are classified within Level 3.

Equity securities consist of mutual funds and common shares in public companies, which are valued by multiplying unadjusted quoted prices in active markets by the quantity of the asset and are classified within Level 1.

Derivative instruments include exchange-traded and bilateral contracts. Exchange-traded derivative contracts include futures and options. Bilateral derivative contracts include swaps, forwards, options and structured transactions. We have classified derivative contracts within the fair value hierarchy as follows:

- Exchange-traded derivative contracts valued by multiplying unadjusted quoted prices in active markets by the quantity of the asset or liability are classified within Level 1.
- Exchange-traded derivative contracts valued using pricing inputs based upon market quotes or market transactions are classified within Level 2. These contracts generally trade in less active markets (i.e., for certain contracts the exchange sets the closing price, which may not be reflective of an actual trade).
- Bilateral derivative contracts where observable inputs are available for substantially the full term and value of the asset or liability are classified within Level 2.

- Bilateral derivative contracts with a lower availability of pricing information are classified in Level 3. In addition, structured transactions, such as certain options, may require us to use internally developed model inputs, which might not be observable in or corroborated by the market, to determine fair value. When such unobservable inputs have more than an insignificant impact on the measurement of fair value, we classify the instrument within Level 3.

During 2011, there were no significant transfers of derivatives between Level 1 and Level 2 of the fair value hierarchy.

We utilize models based upon the income approach to measure the fair value of derivative contracts classified as Level 2 or 3. Generally, we use similar models to value similar instruments. In order to determine fair value, we utilize various inputs and factors including market data and assumptions that market participants would use in pricing assets or liabilities as well as assumptions about the risks inherent in the inputs to the valuation technique. The inputs and factors include:

- forward commodity prices,
- price volatility,
- volumes,
- location,
- interest rates,
- credit quality of counterparties and Constellation Energy, and
- credit enhancements.

The primary input to our valuation models is the forward commodity curve for the respective instrument. Forward commodity curves are derived from published exchange transaction prices, executed bilateral transactions, broker quotes, and other observable or public data sources. The relevant forward commodity curve used to value each of our derivatives will depend on a number of factors including commodity type, location, and expected delivery period. Price volatility would vary by commodity and location. When appropriate, we discount future cash flows using risk free interest rates with adjustments to reflect the credit quality of each counterparty for assets and our own credit quality for liabilities.

We also record valuation adjustments to reflect uncertainty associated with certain estimates inherent in the determination of the fair value of derivative assets and liabilities. The effect of these uncertainties is not incorporated in market price information of other market-based estimates used to determine fair value of our mark-to-market energy contracts.

We describe below the main types of valuation adjustments we record and the process for establishing each. Generally, increases in valuation adjustments reduce our earnings, and decreases in valuation adjustments increase our earnings. However, all or a portion of the effect on earnings of changes in valuation adjustments may be offset by changes in the value of the underlying positions.

- Close-out adjustment—represents the estimated cost to close out or sell to a third party open mark-to-market positions. This valuation adjustment has the effect of valuing “long” positions (the purchase of a commodity) at the bid price and “short” positions (the sale of a commodity) at the offer price. We compute this adjustment using a market-based estimate of the bid/offer spread for each commodity and option price and the absolute quantity of our net open positions for each year. The level of total close-out valuation adjustments increases as we have larger unhedged positions, bid-offer spreads increase, or market information is not available, and it decreases as we reduce our unhedged positions, bid-offer spreads decrease, or market information becomes available.
- Unobservable input valuation adjustment—this adjustment is necessary when we determine fair value for derivative positions using internally developed models that use unobservable inputs due to the absence of observable market information. Unobservable inputs to fair value may arise due to a number of factors, including but not limited to, the term of the transaction, contract optionality, delivery location, or product type. In the absence of observable market information that supports the model inputs, there is a presumption that the transaction price is equal to the market value of the contract when we transact in our principal market and thus we recalibrate our estimate of fair value to equal the transaction price. Therefore we do not recognize a gain or loss at contract inception on these transactions. We will recognize such gains or losses in earnings as we realize cash flows under the contract or when observable market data becomes available.
- Credit-spread adjustment—for risk management purposes, we compute the value of our derivative assets and liabilities using a risk-free discount rate. In order to compute fair value for financial reporting purposes, we adjust the value of our derivative assets to reflect the credit-worthiness of each counterparty based upon either published credit ratings or equivalent internal credit ratings and associated default probability percentages. We compute this adjustment by applying a default probability percentage to our outstanding credit exposure, net of collateral, for each counterparty. The level of this adjustment increases as our credit exposure to counterparties increases, the maturity terms of our transactions

increase, or the credit ratings of our counterparties deteriorate, and it decreases when our credit exposure to counterparties decreases, the maturity terms of our transactions decrease, or the credit ratings of our counterparties improve. As part of our evaluation, we assess whether the counterparties' published credit ratings are reflective of current market conditions. We review available observable data including bond prices and yields and credit default swaps to the extent it is available. We also consider the credit risk measurement implied by that data in determining our default probability percentages, and we evaluate its reliability based upon market liquidity, comparability, and other factors. We also use a credit-spread adjustment in order to reflect our own credit risk in determining the fair value of our derivative liabilities.

We regularly evaluate and validate the inputs we use to estimate fair value by a number of methods, consisting of various market price verification procedures, including the use of pricing services and multiple broker quotes to support the market price of the various commodities in which we transact, as well as review and verification of models and changes to those models. These activities are undertaken by individuals that are independent of those responsible for estimating fair value.

The Company's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the classification of assets and liabilities within the fair value hierarchy. Because of the long-term nature of certain assets and liabilities measured at fair value as well as differences in the availability of market prices and market liquidity over their terms, inputs for some assets and liabilities may fall into any one of the three levels in the fair value hierarchy or some combination thereof. Thus, even though we are required to classify these assets and liabilities in the lowest level in the hierarchy for which inputs are significant to the fair value measurement, a portion of that measurement may be determined using inputs from a higher level in the hierarchy.

The following table sets forth a reconciliation of changes in Level 3 fair value measurements, which predominantly relate to power contracts:

	Year Ended December 31, 2011	2010
	(In millions)	
Balance at beginning of period	**$(197.1)**	$(291.5)
Realized and unrealized (losses) gains:		
Recorded in income	**265.0**	157.1
Recorded in other comprehensive income	**28.2**	95.2
Purchases	**(3.0)**	
Sales	**—**	
Issuances	**24.8**	
Settlements	**—**	
Net purchases, sales, issuances, and settlements (1)	**21.8**	(65.6)
Transfers into Level 3 (2)	**81.6**	73.6
Transfers out of Level 3 (2)	**(49.0)**	(165.9)
Balance at end of year	**$ 150.5**	$(197.1)
Change in unrealized gains recorded in income relating to derivatives still held at end of period	**$ 51.3**	$ 189.6

(1) *Effective January 1, 2011, we are required to present separately purchases, sales, issuances, and settlements.*
(2) *For purposes of this reconciliation, we assumed transfers into and out of Level 3 occurred on the last day of the quarter.*

We have defined the categories of purchases, sales, issuances, and settlements to include the inflow or outflow of value as follows:

- purchases—includes the acquisition of pre-existing derivative contracts,
- sales—includes the sale or assignment of pre-existing derivative contracts,
- issuances—includes the acquisition of derivative contracts and debt securities at inception, and
- settlements—includes the termination of existing derivative contracts prior to normal maturity or settlement.

During 2011, we had purchases related to our business acquisition and issuances related to premiums paid for option contracts and payments for transmission congestion contracts.

Realized and unrealized gains (losses) are included primarily in "Nonregulated revenues" for our derivative contracts that are marked-to-market in our Consolidated Statements of Income (Loss) and are included in "Accumulated other comprehensive loss" for our derivative contracts designated as cash-flow hedges in our Consolidated Balance Sheets. We discuss the income statement classification for realized gains and losses related to cash-flow hedges for our various hedging relationships in *Note 1*.

Realized and unrealized gains (losses) include the realization of derivative contracts through maturity. This includes the fair value, as of the beginning of each quarterly reporting period, of contracts that matured during each quarterly reporting period. Purchases, sales, issuances, and settlements represent cash paid or received for option premiums, and the acquisition or termination of derivative contracts prior to maturity. Transfers into Level 3 represent existing assets or liabilities that were previously categorized at a higher level for which the inputs to the model became unobservable. Transfers out of Level 3 represent assets and liabilities that were previously classified as Level 3 for which the inputs became observable based on the criteria discussed previously for classification in either Level 1 or Level 2. Because the depth and liquidity of the power markets varies substantially between regions and time periods, the availability of observable inputs for substantially the full term and value of our bilateral derivative contracts changes frequently. As a result, we also expect derivatives balances to transfer into and out of Level 3 frequently based on changes in the observable data available as of the end of the period.

Nonrecurring Measurements

The tables below sets forth our assets and liabilities that were measured at fair value on a nonrecurring basis during the year ended December 31, 2011 and 2010:

	Fair Value at December 31, 2011	Losses for the year ended December 31, 2011
	(In millions)	
Investment in CENG	$ 2,150.4	$ 824.2
Other investments:		
Qualifying facilities—coal	22.5	36.7
Qualifying facilities—biomass	24.6	23.3
Qualifying facilities—solar	—	6.8
Total other investments	47.1	66.8
Total	$ 2,197.5	$ 891.0

During the quarter ended December 31, 2011, we recorded other-than-temporary impairment charges of $891.0 million on our equity method investments including CENG and certain of our qualifying facilities. These fair value measurements included significant unobservable inputs, and, as such, the entire amounts of the measurements were classified as Level 3. We discuss these impairment charges, including the inputs and valuation techniques used to estimate the fair value of these equity method investments, in more detail in *Note 2*.

	Fair Value at September 30, 2010	Fair Value at December 31, 2010	Losses for the year ended December 31, 2010
		(In millions)	
Investment in CENG	$ 2,970.4	$ N/A	$ 2,275.0
Other investments:			
UNE	—	N/A	143.4
Qualifying facilities—coal	36.7	N/A	50.0
Qualifying facilities—hydroelectric	N/A	14.8	8.4
Total other investments	36.7	14.8	201.8
Total	$ 3,007.1	$ 14.8	$ 2,476.8

During the quarter ended September 30, 2010, we recorded other-than-temporary impairment charges of $2,468.4 million on our equity method investments including CENG, UNE, and three coal-fired generating facilities located in California. Additionally, during the quarter ended December 31, 2010, we recorded an other-than-temporary impairment charge of $8.4 million on one of our equity investments that own a hydroelectric generating facility in California. These fair value measurements included significant unobservable inputs, and, as such, the entire amounts of the measurements were classified as Level 3. We discuss these impairment charges, including the inputs and valuation techniques used to estimate the fair value of these equity method investments, in more detail in *Note 2*.

There were no nonrecurring measurements in 2009.

Fair Value of Financial Instruments

We show the carrying amounts and fair values of financial instruments included in our Consolidated Balance Sheets in the following table:

At December 31,	**2011**		2010	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
		(In millions)		
Investments and other assets—Constellation Energy	**$ 146.8**	**$ 146.8**	$ 135.7	$ 136.2
Fixed-rate long-term debt:				
Constellation Energy (including BGE)	**4,132.5**	**4,702.8**	4,229.3	4,518.4
BGE	**2,361.9**	**2,636.8**	2,143.6	2,301.8
Variable-rate long-term debt:				
Constellation Energy (including BGE)	**892.3**	**892.3**	528.7	528.7
BGE	**—**	**—**	—	—

We use the following methods and assumptions for estimating fair value disclosures for financial instruments:

- cash and cash equivalents, net accounts receivable, restricted cash, other current assets, certain current liabilities, short-term borrowings, current portion of long-term debt, and certain deferred credits and other liabilities: because of their short-term nature, the amounts reported in our Consolidated Balance Sheets approximate fair value,
- investments and other assets: the fair value is based on quoted market prices where available, and
- long-term debt: the fair value is based on quoted market prices where available or by discounting remaining cash flows at current market rates.

14 Stock-Based Compensation

Under our long-term incentive plans, we grant stock options, performance and service-based restricted stock, performance- and service-based units, stock units, deferred cash and equity to officers, key employees, and members of the Board of Directors. In May 2010, shareholders approved Constellation Energy’s Amended and Restated 2007 Long-Term Incentive Plan, including an increase in the number of shares available for issuance by 9,000,000. Any shares covered by an outstanding award under any of our long-term incentive plans that are forfeited or cancelled, expire or are settled in cash will become available for issuance under the Amended and Restated 2007 Long-Term Incentive Plan. At December 31, 2011, there were 10,143,863 shares available for issuance under the 2007 Long-Term Incentive Plan. At December 31, 2011, we had stock options, restricted stock, performance units and equity grants outstanding as discussed below. We may issue new shares, reuse forfeited shares, or buy shares in the market in order to deliver shares to employees for our equity grants. BGE officers and key employees participate in our stock-based compensation plans. The expense recognized by BGE in 2011, 2010, and 2009 was not material to BGE’s financial results.

Non-Qualified Stock Options

Options are granted with an exercise price equal to the market value of the common stock at the date of grant, become vested over a period up to three years (expense recognized in tranches), and expire ten years from the date of grant.

The fair value of our stock-based awards was estimated as of the date of grant using the Black-Scholes option pricing model based on the following weighted- average assumptions:

	2011	2010	2009
Risk-free interest rate	**1.69%**	1.87%	1.95%
Expected life (in years)	**4.0**	4.0	4.0
Expected market price volatility factor	**27.7%**	32.5%	37.8%
Expected dividend yield	**3.17%**	2.74%	4.83%

We use the historical data related to stock option exercises in order to estimate the expected life of our stock options. We also use historical data (measured on a daily basis) for a period equal to the duration of the expected life of option awards, information on the volatility of an identified group of peer companies, and implied volatilities for certain publicly traded options in Constellation Energy common stock in order to estimate the volatility factor. We believe that the use of this data to estimate these factors provides a reasonable basis for our assumptions. The risk-free interest rate for the periods within the expected life of the option is based on the U.S Treasury yield curve in effect and the expected dividend yield is based on our current estimate for dividend payout at the time of grant.

Summarized information for our stock option grants is as follows:

	2011		2010		2009	
	Shares	**Weighted-Average Exercise Price**	Shares	Weighted-Average Exercise Price	Shares	Weighted-Average Exercise Price
			(Shares in thousands)			
Outstanding, beginning of year	**9,070**	**$ 43.43**	8,146	$ 44.36	6,058	$ 59.99
Granted with exercise prices at fair market value	**2,244**	**30.25**	1,468	35.07	3,511	20.14
Exercised	**(474)**	**23.59**	(235)	23.53	(83)	31.07
Forfeited/expired	**(184)**	**56.58**	(309)	43.41	(1,340)	52.41
Outstanding, end of year	**10,656**	**$ 41.31**	9,070	$ 43.43	8,146	$ 44.36
Exercisable, end of year	**6,539**	**$ 49.15**	5,316	$ 52.65	4,114	$ 55.81
Weighted-average fair value per share of options granted with exercise prices at fair market value		**$ 5.20**		$ 7.60		$ 4.24

The following table summarizes additional information about stock options during 2011, 2010 and 2009:

	2011	2010	2009
		(In millions)	
Stock Option Expense Recognized	**$10.3**	$ 9.9	$14.2
Stock Options Exercised:			
Cash Received for Exercise Price	**11.2**	5.5	2.6
Intrinsic Value Realized by Employee	**5.9**	2.7	0.2
Realized Tax Benefit	**2.4**	1.1	0.1
Fair Value of Options that Vested	**52.4**	54.4	11.0

As of December 31, 2011, we had $4.1 million of unrecognized compensation cost related to the unvested portion of outstanding stock option awards, of which $3.1 million is expected to be recognized during 2012.

The following table summarizes additional information about stock options outstanding at December 31, 2011 (stock options in thousands):

Range of Exercise Prices	Outstanding Stock Options	Outstanding Aggregate Intrinsic Value	Exercisable Stock Options	Exercisable Aggregate Intrinsic Value	Weighted-Average Remaining Contractual Life
		(In millions)		*(In millions)*	*(In years)*
$0 - $ 20	2,524	$ 50.7	1,563	$ 31.4	7.2
$20 - $ 40	4,402	31.2	1,246	5.3	7.6
$40 - $ 60	2,362	—	2,362	—	3.2
$60 - $ 80	717	—	717	—	5.2
$80 - $100	651	—	651	—	6.1
	10,656	$ 81.9	6,539	$ 36.7	

Restricted Stock Awards

In addition to stock options, we issue service-based common stock that vests over periods ranging from one to five years and fully vested common stock units with sales restrictions ranging from approximately 10 months to 5 years. We account for these awards as equity awards, whereby we recognize the value of the market price of the underlying stock on the date of grant as compensation expense immediately for fully vested common stock units with sales restrictions or over the service period either ratably or in tranches (depending if the award has cliff or graded vesting) for service-based common stock.

We recorded compensation expense related to our restricted stock awards of $12.7 million in 2011, $9.5 million in 2010, and $16.7 million in 2009. The tax benefits received associated with our restricted awards were $9.4 million in 2011, $10.0 million in 2010, and $6.7 million in 2009.

Summarized share information for our restricted stock awards is as follows:

	2011	2010	2009
	(Shares in thousands)		
Outstanding, beginning of year	**1,080**	1,017	1,033
Granted	**622**	832	866
Released to participants	**(686)**	(713)	(701)
Canceled	**(48)**	(56)	(181)
Outstanding, end of year	**968**	1,080	1,017
Weighted-average fair value of restricted stock granted (per share)	**$30.27**	$34.83	$19.83
Total fair value of shares for which restriction has lapsed (in millions)	**$ 23.3**	$ 24.9	$ 16.5

As of December 31, 2011, we had $9.2 million of unrecognized compensation cost related to the unvested portion of outstanding restricted stock awards expected to be recognized within a 31-month period. At December 31, 2011, we have recorded in "Common shareholders' equity" approximately $17.2 million and approximately $18.6 million at December 31, 2010 for the unvested portion of service-based restricted stock granted from 2008 until 2011 to officers and other employees.

Performance-Based Units

We recognize compensation expense ratably for our performance-based awards, which are classified as liability awards, for which the fair value of the award is remeasured at each reporting period. Each unit is equivalent to $1 in value and cliff vests at the end of a three-year service and performance period. The level of payout is based on the achievement of certain performance goals at the end of the three-year period and will be settled in cash. We recognized compensation expense of $14.7 million in 2011, compensation expense of $6.2 million in 2010, and compensation expense of $1.5 million in 2009 for these awards. During the 12 months ended December 31, 2011, our 2008 performance-based unit awards vested and we paid $1.3 million. During the 12 months ended December 31, 2010, and 2009, no performance-based unit awards vested. As of December 31, 2011, we had $11.7 million of unrecognized compensation cost related to the unvested portion of outstanding performance-based unit awards expected to be recognized within a 26-month period.

Equity-Based Grants

We recorded compensation expense of $1.1 million in 2011, $0.8 million in 2010, and $0.9 million in 2009 related to equity-based grants to members of the Board of Directors.

15 Merger and Acquisitions

Pending Merger with Exelon Corporation

On April 28, 2011, Constellation Energy entered into an Agreement and Plan of Merger with Exelon Corporation (Exelon). At closing, each issued and outstanding share of common stock of Constellation Energy will be cancelled and converted into the right to receive 0.93 shares of common stock of Exelon, and Constellation Energy will become a wholly owned subsidiary of Exelon.

The merger agreement contains certain termination rights for both Constellation Energy and Exelon. Under narrow specified circumstances in which the merger agreement is terminated and another acquisition proposal is accepted, Constellation Energy may be required to pay Exelon a termination fee of $200 million and Exelon may be required to pay Constellation Energy a termination fee of $800 million.

In connection with the proposed merger, Exelon and Constellation Energy offered numerous commitments, each of which is contingent upon completion of the merger, in support of their request for approval of the merger with the Maryland Public Service Commission (Maryland PSC). In addition, in December 2011, Exelon, Exelon Energy Delivery Company, LLC, Constellation Energy, and BGE entered into a settlement agreement with the State of Maryland, the Maryland Energy Administration, the City of Baltimore, and the Baltimore Building and Construction Trades Council, in which they agreed to several additional commitments contingent upon completion of the merger.

In January 2012, Exelon, Exelon Energy Delivery Company, LLC, Constellation Energy, and BGE entered into a settlement agreement with EDF Group and affiliates (EDF) in which, subject to the consummation of the merger with Exelon, the parties agreed to amendments to the operating agreement of CENG, an existing Administrative Services Agreement (ASA) and an existing Power Services Agency Agreement (PSA). We discuss the ASA and PSA in more detail in *Note 16*.

The merger agreement has been approved by the boards of directors of both Constellation Energy and Exelon and stockholders and by several other state and federal regulatory bodies. The parties are working to complete the merger in the first quarter of 2012 absent any Federal Energy Regulatory Commission approval delays.

Haynesville Shale Gas Property

In the fourth quarter of 2011, we acquired natural gas working interests and net revenue interests in certain producing wells and certain proved developed wells and proved undeveloped locations in Louisiana for a total of approximately $58.2 million, all of which was allocated to property, plant and equipment. This acquisition expanded our physical gas presence and will reduce our collateral costs. We accounted for this acquisition as a business combination within our NewEnergy business segment. The proforma impact of this acquisition would not have been material to our results of operations for the years ended December 31, 2011, 2010, and 2009.

ONEOK Energy Marketing Company

In February 2012, we acquired all of the outstanding stock of ONEOK Energy Marketing Company (OEMC), a retail natural gas marketing company, for approximately $22.5 million, subject to a working capital adjustment. OEMC serves approximately 26,100 customers. This acquisition will expand our retail residential customer base in seven states. We will account for this acquisition as a business combination within our NewEnergy business segment.

MXenergy Holdings Inc.

In July 2011, we acquired all of the outstanding stock of MXenergy Holdings Inc. (MXenergy), a retail energy marketer of natural gas and electricity to residential and commercial customers, for approximately $218.7 million in cash. MXenergy serves approximately 540,000 customers in numerous markets across the United States and Canada.

We recorded the acquisition as follows:

At July 1, 2011	*(In millions)*
Cash and cash equivalents	$ 0.9
Accounts receivable	53.8
Restricted cash (1)	63.8
Other current assets	38.4
Goodwill (2)	108.8
Acquired contracts and intangibles (2)(3)	84.5
Other assets	13.0
Total assets acquired	363.2
Bond payable (1)	(82.9)
Other current liabilities	(60.4)
Noncurrent liabilities	(1.2)
Total liabilities	(144.5)
Net assets acquired	$ 218.7

(1) *The bond payable was fully repaid during August 2011 primarily with the restricted cash.*
(2) *None is deductible for tax purposes.*
(3) *The weighted average amortization for these assets is approximately 4 years.*

We have included MXenergy's results of operations in our consolidated financial statements as part of our NewEnergy business segment since the date of acquisition.

The proforma impact of this acquisition would not have been material to our results of operations for the years ended December 31, 2011, 2010, and 2009.

Star Electricity, Inc.

In May 2011, we acquired all of the outstanding stock of Star Electricity, Inc. (StarTex), a retail electric provider, for approximately $160.4 million in cash. StarTex serves approximately 170,000 customers in the Texas residential market.

We recorded the acquisition as follows:

At May 27, 2011	(In millions)
Cash and cash equivalents	$ 17.9
Other current assets	42.7
Goodwill(1)	93.6
Acquired contracts and intangibles(1)(2)	78.3
Other assets	1.3
Total assets acquired	233.8
Total liabilities	(73.4)
Net assets acquired	$ 160.4

(1) None is deductible for tax purposes.
(2) The weighted average amortization for these assets is approximately 3 years.

The net assets acquired amounts are preliminary pending final purchase price adjustments.

We have included StarTex's results of operations in our consolidated financial statements as part of our NewEnergy business segment since the date of acquisition.

The proforma impact of this acquisition would not have been material to our results of operations for the quarters and six months ended June 30, 2011 and 2010 and to our financial condition as of June 30, 2011 and December 31, 2010.

Boston Generating

In January 2011, we acquired Boston Generating's 2,950 MW fleet of generating plants for cash of approximately $1.1 billion. The fleet acquired includes the following four natural gas power plants and one fuel oil plant located in the Boston, Massachusetts area:

- Mystic 7—574 MW,
- Mystic 8 and 9—1,580 MW,
- Fore River—787 MW, and
- Mystic Jet, a fuel oil plant—9 MW.

We recorded the acquisition as follows:

At January 3, 2011	*(In millions)*
Current assets	$ 92.2
Land	29.2
Property, plant and equipment	1,061.8
Noncurrent assets	0.1
Total assets acquired	1,183.3
Current liabilities	(77.5)
Noncurrent liabilities	(21.8)
Total liabilities	(99.3)
Net assets acquired	$ 1,084.0

We have included the results of operations from these plants in our consolidated financial statements as part of our Generation business segment since the date of acquisition.

The proforma impact of this acquisition would not have been material to our results of operations for the quarters ended March 31, 2011 and 2010 and to our financial condition as of March 31, 2011 and December 31, 2010.

CPower

In October 2010, we acquired 100% ownership of CPower, an energy management and demand response provider, for $77.1 million in cash, all of which was paid at closing. CPower designs and manages programs that allow its customers to reduce electricity demand at times of peak usage. We have included CPower's results of operations in our consolidated financial statements as part of our NewEnergy business segment since the date of acquisition.

We recorded the acquisition as follows:

At October 11, 2010	*(In millions)*
Cash and cash equivalents	$ 2.9
Other current assets	12.9
Goodwill (1)	54.3
Acquired intangible assets (2)	12.6
Other assets	10.6
Total assets acquired	93.3
Total liabilities	(16.2)
Net assets acquired	$ 77.1

(1) $3.6 million is deductible for tax purposes.

(2) The weighted average amortization for these intangibles is approximately 2 years.

The pro-forma impact of this acquisition would not have been material to our results of operations for the years ended December 31, 2010 and 2009.

Texas Combined Cycle Generation Facilities

In May 2010, we acquired 100% ownership of the 550 MW Colorado Bend Energy Center and the 550 MW Quail Run Energy Center natural gas combined cycle generation facilities in Texas for $372.9 million, all of which was paid in cash at closing. We include these facilities as part of our Generation business and have included their results of operations in our consolidated financial statements since the date of acquisition.

We recorded the acquisition as follows:

At May 17, 2010	*(In millions)*
Current assets	$ 7.1
Property, plant and equipment	368.6
Total assets acquired	375.7
Current liabilities	(2.8)
Net assets acquired	$ 372.9

The pro-forma impact of this acquisition would not have been material to our results of operations for the years ended December 31, 2010 and 2009.

Criterion Wind Project

In April 2010, we acquired 100% ownership of a 70 MW Criterion wind project to be constructed in Garrett County, Maryland. In December 2010, we placed this facility in commercial operation. This wind energy project was developed, constructed, and is owned by our Generation business.

The pro-forma impact of all of the 2010 acquisitions, collectively, would not have been material to our results of operations for the years ended December 31, 2010 and 2009.

16 Related Party Transactions

Constellation Energy

CENG

We have a unit contingent power purchase agreement (PPA) with CENG under which we purchase between 85-90% of the output of CENG's nuclear plants that is not sold to third parties under pre-existing PPAs through 2014. Beginning on January 1, 2015 and continuing to the end of the life of the respective plants, we will purchase 50.01% of the output of CENG's nuclear plants, and EDF will purchase 49.99% of that output.

In addition to the PPA, we have a power services agency agreement (PSA) and an administrative service agreement (ASA) with CENG. The PSA is a five-year agreement under which we will provide scheduling, asset management and billing services to CENG and recognize average annual revenue of approximately $16 million. The ASA expires in 2017 and under the agreement we provide certain administrative services to CENG including back office, human resources and information technology. The ASA includes both a consumption-based pricing structure as well as a fixed-price structure which are subject to change in future years based on the level of service needed. The fixed price fee for 2011 is approximately $48 million and will increase annually in line with inflation. The charges under this agreement are intended to represent the actual cost of the services provided to CENG by us.

The impact of transactions under these agreements is summarized below:

	Increase (Decrease) in Earnings				
Agreement	Year Ended December 31, 2011	Year Ended December 31, 2010	Period from November 6, 2009 through December 31, 2009	Income Statement Classification	Accounts Receivable/ (Accounts Payable)— December 31, 2011
PPA	$ (888.4)	$ (900.8)	$ (122.5)	Fuel and purchased energy expenses	$ (47.5)
PSA	16.1	16.1	2.7	Nonregulated revenues	—
ASA	48.0	66.0	10.0	Operating expenses	4.0

Upon the closing of the merger with Exelon, the ASA will be amended to reflect actual post-merger costs determined on the same basis that Exelon charges its affiliates for similar services. In addition, the PSA will be amended to reflect the cost of the service, with such cost not to exceed approximately $358,000 per month.

In May 2011, CENG issued an unsecured revolving promissory note to borrow up to an aggregate principal amount of $62.5 million from a subsidiary of Constellation Energy. CENG also issued an unsecured revolving promissory note to EDF on substantially identical terms, such that any request for borrowings by CENG must be submitted 50% to Constellation Energy and 50% to EDF.

Interest accrues on the amounts borrowed on a daily basis at a fixed rate per year equal to the rate at which deposits of United States dollars are offered by prime banks in the London interbank market, plus 250 basis points. Amounts are due at the earlier of October 31, 2012 or the date upon which the note is accelerated in accordance with the terms of the agreement.

As of December 31, 2011, CENG has borrowed $30.0 million from Constellation Energy.

During 2011, CENG executed settlement agreements with the DOE that detail a framework and procedure for recovery of damages incurred or to be incurred through the end of 2013. Constellation Energy, through its share of the settlement proceeds, recognized a total of $93.8 million in 2011 for costs incurred to store spent nuclear fuel. We discuss this settlement in more detail in *Note 2*.

UNE

We sold our interest in UNE during 2010. We discuss this transaction in more detail in *Note 4*.

CEP

In August 2011, we sold a majority of our interests in Constellation Energy Partners LLC (CEP) to PostRock Energy Corporation (PostRock). As a result of this transaction, we recorded a pre-tax gain of $23.0 million.

Additionally, in December 2011, we sold our remaining Class B member interests to PostRock. We recorded a pre-tax gain of $10.7 million on this transaction.

We discuss these transactions in more detail in *Note 2*.

BGE—Income Statement

BGE is obligated to provide market-based standard offer service to all of its electric customers for varying periods. Bidding to supply BGE's market-based standard offer service to electric customers will occur from time to time through a competitive bidding process approved by the Maryland PSC.

Our NewEnergy business will supply a portion of BGE's market-based standard offer service obligation to electric customers through May 31, 2014.

The cost of BGE's purchased energy from nonregulated subsidiaries of Constellation Energy to meet its standard offer service obligation was as follows:

Year Ended December 31,	**2011**	2010	2009
		(In millions)	
Electricity purchased for resale expenses	**$348.2**	$428.0	$623.5

In addition, Constellation Energy charges BGE for the costs of certain corporate functions. Certain costs, both capital and expense, are directly assigned to BGE. We allocate other corporate function costs based on a total percentage of expected use by BGE. We believe this method of allocation is reasonable and approximates the cost BGE would have incurred as an unaffiliated entity.

The following table presents all of the costs Constellation Energy charged to BGE in each period, both directly-charged and allocated.

Year ended December 31,	**2011**	2010	2009
		(In millions)	
Charges to BGE	**$178.6**	$184.8	$164.7

Other nonregulated affiliates of BGE also charge BGE for the costs of certain services provided.

BGE—Balance Sheet

Through January 7, 2010, BGE participated in a cash pool under a Master Demand Note agreement with Constellation Energy. Under this arrangement, participating subsidiaries may invest in or borrow from the pool at market interest rates. Constellation Energy administers the pool and invests excess cash in short-term investments or issues commercial paper to manage consolidated cash requirements.

As part of the ring-fencing measures required by the Maryland PSC in its order approving the transaction with EDF, BGE ceased participation in the cash pool on January 7, 2010.

BGE's Consolidated Balance Sheets include intercompany amounts related to BGE's purchases to meet its standard offer service obligation, BGE's charges to Constellation Energy and its nonregulated affiliates for certain services it provides them, Constellation Energy and its nonregulated affiliates' charges to BGE, and the participation of BGE's employees in the Constellation Energy defined benefit plans.

17 Quarterly Financial Data (Unaudited)

Our quarterly financial information has not been audited but, in management's opinion, includes all adjustments necessary for a fair statement. Our business is seasonal in nature with the peak sales periods generally occurring during the summer and winter months. Accordingly, comparisons among quarters of a year may not represent overall trends and changes in operations.

2011 Quarterly Data—Constellation Energy

	Revenues *	Fuel and Purchased Energy Expenses (includes amounts from affiliates) *	(Loss) Income from Operations	Net Income (Loss)	Net Income (Loss) Attributable to Common Stock	Earnings (Loss) Per Share from Operations — Diluted	Earnings (Loss) Per Share of Common Stock— Diluted
	(In millions, except per share amounts)						
Quarter Ended							
March 31	$ 3,570.2	$ 2,673.0	$ 217.6	$ 79.4	$ 70.4	$ 0.35	$ 0.35
June 30	3,359.8	2,380.9	260.1	108.1	99.2	0.49	0.49
September 30	3,875.4	2,984.6	229.8	97.9	73.7	0.36	0.36
December 31	2,952.8	2,246.5	(904.5)	(592.2)	(583.6)	(2.91)	(2.91)
Year Ended December 31	$13,758.2	$ 10,285.0	$ (197.0)	$ (306.8)	$ (340.3)	$ (1.70)	$ (1.70)

2011 Quarterly Data—BGE

	Revenues	Income from Operations	Net Income	Net Income (Loss) Attributable to Common Stock
	(In millions)			
Quarter Ended				
March 31	$ 957.5	$ 153.4	$ 81.1	$ 77.8
June 30	656.2	52.7	16.6	13.3
September 30	722.9	22.8	1.6	(1.7)
December 31	656.5	85.9	36.4	33.1
Year Ended December 31	$ 2,993.1	$ 314.8	$ 135.7	$ 122.5

The sum of the quarterly earnings per share amounts may not equal the total for the year due to the effects of rounding and dilution.

* *In the fourth quarter of 2011, we identified adjustments that were required to revise certain unaffiliated amounts between "Revenues" and "Fuel and Purchased Energy Expenses" for the third quarter of 2011 in order to properly reflect activity in our Consolidated Statements of Income (Loss). This revision did not impact reported gross margin, income (loss) from operations, net income (loss), net income (loss) attributable to common stock, or cash flows from operations for the third quarter of 2011.*

First quarter results include:

- a $17.6 million after-tax charge for amortization of the basis difference in CENG,
- a $27.0 million after-tax charge for the impact of the PPA with CENG,
- a $10.0 million after-tax charge for transaction fees incurred related to our acquisition of Boston Generating's 2,950 MW fleet of generating plants in Massachusetts, and
- a $1.5 million after-tax amortization of credit facility amendment fees in connection with the EDF transaction.

Second quarter results include:

- a $24.0 million after-tax charge for amortization of the basis difference in CENG,
- a $30.3 million after-tax charge for the impact of the PPA with CENG,
- a $19.3 million after-tax charge for costs incurred related to our pending merger with Exelon,

- a $21.3 million after-tax gain on the settlement with the DOE for storage of spent nuclear fuel at the Calvert Cliffs nuclear power plant through October 2008,
- a $0.1 million after-tax charge for transaction fees incurred related to our acquisition of Boston Generating's 2,950 MW fleet of generating plants in Massachusetts,
- a $1.5 million after-tax amortization of credit facility amendment fees in connection with the EDF transaction.

Third quarter results include:

- a $26.3 million after-tax charge for amortization of the basis difference in CENG,
- a $31.3 million after-tax charge for the impact of the PPA with CENG,
- a $24.6 million after-tax charge for incremental operating expenses incurred related to Hurricane Irene,
- a $14.3 million after-tax gain on the sale of interests in CEP,
- a $5.1 million after-tax charge for costs incurred related to our pending merger with Exelon, and
- a $1.5 million after-tax amortization of credit facility amendment fees in connection with the EDF transaction.

Fourth quarter results include:

- a $530.2 million after-tax charge for the impairment of certain of our equity method investments,
- a $22.6 million after-tax charge for amortization of the basis difference in CENG,
- a $29.9 million after-tax charge for the impact of the PPA with CENG,
- a $18.4 million after-tax gain on the sale of additional interests in CEP and certain working interests in upstream natural gas properties,
- a $46.5 million after-tax charge for costs incurred related to our pending merger with Exelon,
- a $36.0 million after-tax gain on the settlement with the DOE for storage of spent nuclear fuel at the Calvert Cliffs nuclear power plant and the Ginna nuclear power plant through November 6, 2009,
- a $0.2 million after-tax benefit for an income tax true-up for costs incurred related to our acquisition of Boston Generating's 2,950 MW fleet of generating plants in Massachusetts, and
- a $1.3 million after-tax amortization of credit facility amendment fees in connection with the EDF transaction.

We discuss these items in *Note 2*.

2010 Quarterly Data—Constellation Energy

	Revenues	Income (Loss) from Operations	Net Income (Loss)	Net Income (Loss) Attributable to Common Stock	Earnings (Loss) Per Share from Operations — Diluted	Earnings (Loss) Per Share of Common Stock—Diluted
	(In millions, except per share amounts)					
Quarter Ended						
March 31	**$ 3,586.6**	**$ 415.1**	**$ 191.3**	**$ 191.5**	**$ 0.95**	**$ 0.95**
June 30	**3,309.9**	**181.9**	**83.8**	**72.6**	**0.36**	**0.36**
September 30	**3,968.9**	**(2,246.7)**	**(1,375.0)**	**(1,406.5)**	**(6.99)**	**(6.99)**
December 31	**3,474.6**	**406.7**	**168.1**	**159.8**	**0.79**	**0.79**
Year Ended December 31	**$14,340.0**	**$ (1,243.0)**	**$ (931.8)**	**$ (982.6)**	**$ (4.90)**	**$ (4.90)**

2010 Quarterly Data—BGE

	Revenues	Income from Operations	Net Income	Net Income Attributable to Common Stock
	(In millions)			
Quarter Ended				
March 31	**$ 1,069.3**	**$ 136.9**	**$ 64.4**	**$ 61.1**
June 30	**751.5**	**55.9**	**17.0**	**13.7**
September 30	**856.1**	**75.6**	**31.8**	**28.5**
December 31	**784.8**	**85.8**	**34.4**	**31.1**
Year Ended December 31	**$ 3,461.7**	**$ 354.2**	**$ 147.6**	**$ 134.4**

The sum of the quarterly earnings per share amounts may not equal the total for the year due to the effects of rounding and dilution.

First quarter results include:

- a $8.8 million after-tax charge for the deferred income tax expense impact relating to federal subsidies for providing post-employment prescription drug benefits,
- a $30.9 million after-tax loss for the early retirement of 2012 Notes,
- a $25.7 million after-tax charge for amortization of the basis difference in CENG,
- a $25.7 million after-tax charge for the impact of the PPA with CENG, and
- a $2.9 million after-tax amortization of credit facility amendment fees in connection with the EDF transaction.

Second quarter results include:

- a $37.0 million after-tax charge for amortization of the basis difference in CENG,
- a $29.1 million after-tax charge for the impact of the PPA with CENG, and
- a $2.9 million after-tax amortization of credit facility amendment fees in connection with the EDF transaction.

Third quarter results include:

- a $1,465.3 million after-tax charge for the impairment of certain of our equity method investments,
- a $31.5 million after-tax charge for amortization of the basis difference in CENG,
- a $28.9 million after-tax charge for the impact of the PPA with CENG,
- a $24.7 million after-tax gain on the sale of our interest in the Mammoth Lakes geothermal generating facility, and
- a $2.9 million after-tax amortization of credit facility amendment fees in connection with the EDF transaction.

Fourth quarter results include:

- a $21.8 million after-tax charge for an impairment and an adjustment to income tax expenses associated with certain of our equity method investments,
- a $23.3 million after-tax charge for amortization of the basis difference in CENG,
- a $29.6 million after-tax charge for the impact of the PPA with CENG,
- a $35.4 million after-tax gain on the settlement of an international coal contract dispute,
- a $121.3 million after-tax gain on the comprehensive agreement with EDF, and
- a $4.9 million after-tax amortization of credit facility amendment fees in connection with the EDF transaction.

We discuss these items in *Note 2*.

18 Constellation Condensed Consolidating Financial Information

The following condensed consolidating income statements, balance sheets and statements of cash flow depict Constellation's nonregulated businesses, including the generation and customer supply businesses, which Exelon contributed to Generation subsequent to Exelon's acquisition of Constellation.

The adjustments column of the consolidated income statements below primarily represents the intercompany revenue between Constellation's nonregulated businesses and BGE and the elimination of operating and maintenance expenses allocated from Constellation's parent company to BGE. The adjustments column of the consolidated balance sheets below primarily reflects the elimination of dividends declared, as well as pension and postretirement balances and related equity and deferred income tax amounts, that are held at the Constellation's parent company. The adjustments column of the consolidated statements of cash flow below primarily reflects the adjustment for dividends and intercompany activity.

CONDENSED CONSOLIDATING INCOME STATEMENT

Year Ended December 31, 2011	Constellation	BGE Subtract (Add)	Adjustments Add (Subtract)	Nonregulated Constellation
		(In millions, except per share amounts)		
Revenues				
Nonregulated revenues	$ 10,773	$ —	$ —	$ 10,773
Nonregulated revenues from affiliate	—	—	340	340
Regulated electric revenues	2,321	2,321	—	—
Regulated gas revenues	664	672	8	—
Total revenues	13,758	2,993	348	11,113
Expenses				
Fuel and purchased energy expenses	9,397	1,171	—	8,226
Fuel and purchased energy expenses from affiliate (CENG)	888	—	—	888
Fuel and purchased energy expenses from affiliate	—	348	348	—
Operating expenses	1,935	552	(115)	1,268
Operating expenses from affiliate	—	115	115	—
Merger costs	118	30	—	88
Impairment losses and other costs	891	—	—	891
Depreciation, depletion, accretion, and amortization	589	272	—	317
Taxes other than income taxes	308	190	—	118
Total expenses	14,126	2,678	348	11,796
Equity Investment Earnings	20	—	—	20
Gain on U.S. Department of Energy Settlement	94	—	—	94
Net Gain on Divestitures	57	—	—	57
(Loss) Income from Operations	(197)	315	—	(512)
Other (Expenses) Income	(76)	21	—	(97)
Interest expense	277	134	—	143
Interest capitalized and allowance for borrowed funds used during construction	(12)	(7)	—	(5)
Total fixed charges	265	127	—	138
(Loss) Income from Continuing Operations Before Income Taxes	(538)	209	—	(747)
Income Tax (Benefit) Expense	(231)	73	—	(304)
Net (Loss) Income	(307)	136	—	(443)
Net Income Attributable to Noncontrolling Interests and BGE Preference Stock Dividends	33	13	—	20
Net (Loss) Income Attributable to Common Stock	$ (340)	$ 123	$ —	$ (463)

CONDENSED CONSOLIDATING INCOME STATEMENT

Year Ended December 31, 2010	Constellation	BGE Subtract (Add)	Adjustments Add (Subtract)	Nonregulated Constellation
		(In millions, except per share amounts)		
Revenues				
Nonregulated revenues	$ 10,883	$ —	$ —	$ 10,883
Nonregulated revenues from affiliate	—	—	423	423
Regulated electric revenues	2,752	2,752	—	—
Regulated gas revenues	705	710	5	—
Total revenues	14,340	3,462	428	11,306
Expenses				
Fuel and purchased energy expenses	10,002	1,640	—	8,362
Fuel and purchased energy expenses from affiliate (CENG)	901	—	—	901
Fuel and purchased energy expenses from affiliate	—	428	428	—
Operating expenses	1,691	485	(122)	1,084
Operating expenses from affiliate	—	122	122	—
Impairment losses and other costs	2,477	—	—	2,477
Depreciation, depletion, accretion, and amortization	520	249	—	271
Taxes other than income taxes	263	184	—	79
Total expenses	15,854	3,108	428	13,174
Equity Investment Earnings	25	—	—	25
Net Gain on Divestitures	246	—	—	246
(Loss) Income from Operations	(1,243)	354	—	(1,597)
Other (Expenses) Income	(77)	21	—	(98)
Interest expense	311	136	—	175
Interest capitalized and allowance for borrowed funds used during construction	(33)	(6)	—	(27)
Total fixed charges	278	130	—	148
(Loss) Income from Continuing Operations Before Income Taxes	(1,598)	245	—	(1,843)
Income Tax (Benefit) Expense	(666)	97	—	(763)
Net (Loss) Income	(932)	148	—	(1,080)
Net Income Attributable to Noncontrolling Interests and BGE Preference Stock Dividends	51	14	—	37
Net (Loss) Income Attributable to Common Stock	$ (983)	$ 134	$ —	$ (1,117)

CONDENSED CONSOLIDATING INCOME STATEMENT

Year Ended December 31, 2009	Constellation	BGE Subtract (Add)	Adjustments Add (Subtract)	Nonregulated Constellation
		(In millions, except per share amounts)		
Revenues				
Nonregulated revenues	$ 12,024	$ —	$ —	$ 12,024
Nonregulated revenues from affiliate	—	—	620	620
Regulated electric revenues	2,821	2,821	—	—
Regulated gas revenues	754	758	4	—
Total revenues	15,599	3,579	624	12,644
Expenses				
Fuel and purchased energy expenses	11,013	1,667	—	9,346
Fuel and purchased energy expenses from affiliate (CENG)	123	—	—	123
Fuel and purchased energy expenses from affiliate	—	624	624	—
Operating expenses	2,228	434	(126)	1,668
Operating expenses from affiliate	—	126	126	—
Merger costs	146	—	—	146
Impairment losses and other costs	125	20	—	105
Workforce reduction costs	13	—	—	13
Depreciation, depletion, accretion, and amortization	651	262	—	389
Taxes other than income taxes	290	178	—	112
Total expenses	14,589	3,311	624	11,902
Equity Investment Losses	(6)	—	—	(6)
Gain on Sale of Interest in CENG	7,446	—	—	7,446
Net Loss on Divestitures	(469)	—	—	(469)
Income from Operations	7,981	268	—	7,713
Other (Expenses) Income	(141)	25	—	(166)
Interest expense	437	144	—	293
Interest capitalized and allowance for borrowed funds used during construction	(87)	(5)	—	(82)
Total fixed charges	350	139	—	211
Income from Continuing Operations Before Income Taxes	7,490	154	—	7,336
Income Tax Expense	2,987	63	—	2,924
Net Income	4,503	91	—	4,412
Net Income Attributable to Noncontrolling Interests and BGE Preference Stock Dividends	60	6	—	54
Net Income Attributable to Common Stock	$ 4,443	$ 85	$ —	$ 4,358

CONDENSED CONSOLIDATING BALANCE SHEETS

At December 31, 2011	Constellation	BGE Subtract (Add)	Adjustments Add (Subtract)	Nonregulated Constellation
			(In millions)	
Assets				
Current Assets				
Cash and cash equivalents	$ 965	$ 49	$ —	$ 916
Accounts receivable, affiliated companies	—	2	68	66
Fuel stocks	423	74	—	349
Materials and supplies	130	34	—	96
Derivative assets	358	—	—	358
Unamortized energy contract assets	52	—	—	52
Restricted cash	2	—	—	2
Regulatory assets (net)	154	154	—	—
Deferred income taxes	132	—	—	132
Other	2,603	635	—	1,968
Total current assets	4,819	948	68	3,939
Investments and Other Noncurrent Assets				
Investment in CENG	2,150	—	—	2,150
Other investments	122	—	—	122
Goodwill	282	—	—	282
Derivative assets	259	—	—	259
Unamortized energy contract assets	58	—	—	58
Receivable, affiliated companies	—	514	595	81
Other	723	395	(45)	283
Other—consolidated variable interest entities	97	—	—	97
Total investments and other noncurrent assets	3,691	909	550	3,332
Property, Plant and Equipment				
Nonregulated property, plant and equipment	7,780	—		7,780
Regulated property, plant and equipment	7,595	7,595	—	—
Accumulated depreciation	(4,472)	(2,465)	—	(2,007)
Net property, plant and equipment	10,903	5,130	—	5,773
Total Assets	$ 19,413	$ 6,987	$ 618	$ 13,044

CONDENSED CONSOLIDATING BALANCE SHEETS

At December 31,2011	Constellation	BGE Subtract (Add)	Adjustments Add (Subtract)	Nonregulated Constellation
			(In millions)	
Liabilities and Equity				
Current Liabilities				
Current portion of long-term debt	110	110	—	—
Accounts payable, affiliated companies	—	66	68	2
Derivative liabilities	780	—	—	780
Accrued expenses	431	41	—	390
Other	1,967	523	(48)	1,396
Total current liabilities	3,288	740	20	2,568
Deferred Credits and Other Noncurrent Liabilities				
Deferred income taxes	2,305	1,484	392	1,213
Payable, affiliated company	—	253	313	60
Derivative liabilities	268	—	—	268
Unamortized energy contract liabilities	295	—	—	295
Defined benefit obligations	698	—	(698)	—
Other	314	23	—	291
Total deferred credits and other noncurrent liabilities	3,880	1,760	7	2,127
Long-term Debt, Net of Current Portion	4,456	1,854	(2,250)	352
Long-term Debt to Affiliate, Net of Current Portion	—	—	2,250	2,250
Long-term Debt, Net of Current Portion—consolidated variable interest entities	388	332	—	56
Equity				
Common shareholders’ equity	7,094	2,111	591	5,574
BGE preference stock not subject to mandatory redemption	190	190	—	—
Noncontrolling interests	117	—	—	117
Total equity	7,401	2,301	591	5,691
Commitments, Guarantees, and Contingencies				
Total Liabilities and Equity	$ 19,413	$ 6,987	$ 618	$ 13,044

CONDENSED CONSOLIDATING BALANCE SHEETS

At December 31, 2010	Constellation	BGE Subtract (Add)	Adjustments Add (Subtract)	Nonregulated Constellation
			(In millions)	
Assets				
Current Assets				
Cash and cash equivalents	$ 2,029	$ 50	$ —	$ 1,979
Accounts receivable	2,059	620	—	1,439
Accounts receivable, affiliated companies	—	1	86	85
Fuel stocks	361	67	—	294
Materials and supplies	104	31	—	73
Derivative assets	534	—	—	534
Unamortized energy contract assets	545	—	—	545
Restricted cash	52	—	—	52
Regulatory assets (net)	79	79	—	—
Other	690	146	—	544
Total current assets	6,453	994	86	5,545
Investments and Other Noncurrent Assets				
Investment in CENG	2,991	—	—	2,991
Other investments	190	—	—	190
Goodwill	77	—	—	77
Unamortized energy contract assets	110	—	—	110
Receivable, affiliated companies	—	494	581	87
Other	919	427	(46)	446
Total investments and other noncurrent assets	4,287	921	535	3,901
Property, Plant and Equipment				
Nonregulated property, plant and equipment	6,387	—	—	6,387
Regulated property, plant and equipment	7,202	7,202	—	—
Accumulated depreciation	(4,310)	(2,450)	—	(1,860)
Net property, plant and equipment	9,279	4,752	—	4,527
Total Assets	$ 20,019	$ 6,667	$ 621	$ 13,973

CONDENSED CONSOLIDATING BALANCE SHEETS

At December 31, 2010	Constellation	BGE Subtract (Add)	Adjustments Add (Subtract)	Nonregulated Constellation
			(In millions)	
Liabilities and Equity				
Current Liabilities				
Current portion of long-term debt	246	22	—	224
Accounts payable	1,073	253	—	820
Accounts payable, affiliated companies	—	85	86	1
Derivative liabilities	622	—	—	622
Deferred income taxes	56	—	—	56
Other	1,280	350	(49)	881
Total current liabilities	3,277	710	37	2,604
Deferred Credits and Other Noncurrent Liabilities				
Deferred income taxes	2,490	1,355	339	1,474
Payable, affiliated company	—	251	309	58
Derivative liabilities	353	—	—	353
Unamortized energy contract liabilities	411	—	—	411
Defined benefit obligations	575	—	(575)	—
Other	356	28	—	328
Total deferred credits and other noncurrent liabilities	4,185	1,634	73	2,624
Long-term Debt, Net of Current Portion	4,054	1,665	(2,250)	139
Long-term Debt to Affiliate, Net of Current Portion	—	—	2,250	2,250
Long-term Debt, Net of Current Portion — consolidated variable interest entities	395	395	—	—
Equity				
Common shareholders' equity	7,829	2,073	511	6,267
BGE preference stock not subject to mandatory redemption	190	190	—	—
Noncontrolling interests	89	—	—	89
Total equity	8,108	2,263	511	6,356
Commitments, Guarantees, and Contingencies				
Total Liabilities and Equity	$ 20,019	$ 6,667	$ 621	$ 13,973

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

Year Ended December 31, 2011	Constellation	BGE Subtract (Add)	Adjustments Add (Subtract)	Nonregulated Constellation
		(In millions)		
Net Cash Provided by Operating Activities	$ 1,254	$ 431	$ —	$ 823
Cash Flows From Investing Activities				
Investments in property, plant and equipment	(1,107)	(588)	—	(519)
Asset acquisitions and business combinations, net of cash acquired	(1,502)	—	—	(1,502)
Proceeds from U. S. Department of Energy grant	41	41	—	—
Proceeds from sales of investments and other assets	106	—	—	106
Proceeds from investment tax credits and grants related to renewable energy investments	82	—	—	82
Payment for issuance of loans receivable	(75)	—	—	(75)
Proceeds from repayment of loans receivable	45	—	—	45
Contract and portfolio acquisitions	(4)	—	—	(4)
Decrease in restricted funds	52	—	—	52
Other	(18)	—	—	(18)
Net cash (used in) investing activities	(2,380)	(547)	—	(1,833)
Cash Flows From Financing Activities				
Net repayment of short-term borrowings	(12)	—	—	(12)
Proceeds from issuance of common stock	21	—	—	21
Proceeds from issuance of long-term debt	564	300	—	264
Common stock dividends paid	(183)	—	183	—
BGE preference stock dividends paid	(13)	(13)	—	—
Proceeds from contract and portfolio acquisitions	2	—	—	2
Repayment of long-term debt	(305)	(82)	—	(223)
Derivative contracts classified as financing activities	(9)	—	—	(9)
Debt and credit facility costs	(3)	(5)	—	2
Contribution from parent	—	—	85	85
Contribution to parent	—	(85)	(268)	(183)
Net cash provided by (used in) financing activities	62	115	—	(53)
Net (Decrease) in Cash and Cash Equivalents	(1,064)	(1)	—	(1,063)
Cash and Cash Equivalents at Beginning of Year	2,029	50	—	1,979
Cash and Cash Equivalents at End of Year	$ 965	$ 49	$ —	$ 916

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

Year Ended December 31, 2010	Constellation	BGE Subtract (Add)	Adjustments Add (Subtract)	Nonregulated Constellation
		(In millions)		
Net Cash Provided by Operating Activities	$ 511	$ 318	$ —	$ 193
Cash Flows From Investing Activities				
Investments in property, plant and equipment	(1,050)	(552)	—	(498)
Asset acquisitions and business combinations, net of cash acquired	(446)	—	—	(446)
Proceeds from U. S. Department of Energy grant	55	55	—	—
Proceeds from sales of investments and other assets	244	21	—	223
Change in cash pool at parent	—	315	—	(315)
Proceeds from investment tax credits and grants related to renewable energy investments	57	—	—	57
Contract and portfolio acquisitions	(208)	—	—	(208)
Increase in restricted funds	(60)	(5)	—	(55)
Other	(36)	—	—	(36)
Net cash (used in) investing activities	(1,444)	(166)	—	(1,278)
Cash Flows From Financing Activities				
Net repayment of short-term borrowings	(14)	(46)	—	32
Proceeds from issuance of common stock	14	—	—	14
Proceeds from issuance of long-term debt	550	—	—	550
Common stock dividends paid	(183)	—	183	—
BGE preference stock dividends paid	(13)	(13)	—	—
Proceeds from contract and portfolio acquisitions	52	—	—	52
Repayment of long-term debt	(665)	(57)	—	(608)
Derivative contracts classified as financing activities	(186)	—	—	(186)
Debt and credit facility costs	(33)	—	—	(33)
Contribution to parent	—	—	(183)	(183)
Net cash (used in) financing activities	(478)	(116)	—	(362)
Net (Decrease) Increase in Cash and Cash Equivalents	(1,411)	36	—	(1,447)
Cash and Cash Equivalents at Beginning of Year	3,440	14	—	3,426
Cash and Cash Equivalents at End of Year	$ 2,029	$ 50	$ —	$ 1,979

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

Year Ended December 31, 2009	Constellation	BGE Subtract (Add)	Adjustments Add (Subtract)	Nonregulated Constellation
		(In millions)		
Net Cash Provided by Operating Activities	$ 4,391	$ 646	$ —	$ 3,745
Cash Flows From Investing Activities				
Investments in property, plant and equipment	(1,530)	(373)	—	(1,157)
Asset acquisitions and business combinations, net of cash acquired	(41)	—	—	(41)
Investments in nuclear decommissioning trust fund securities	(385)	—	—	(385)
Proceeds from nuclear decommissioning trust fund securities	367	—	—	367
Investments in joint ventures	(202)	—	—	(202)
Proceeds from sale of 49.99% membership interest in CENG	3,529	—	—	3,529
Proceeds from sales of investments and other assets	88	—	—	88
Change in cash pool at parent	—	(166)	—	166
Contract and portfolio acquisitions	(2,154)	—	—	(2,154)
Decrease in restricted funds	1,003	—	—	1,003
Other	1	—	—	1
Net cash provided by (used in) investing activities	676	(539)	—	1,215
Cash Flows From Financing Activities				
Net repayment of short-term borrowings	(810)	(324)	—	(486)
Proceeds from issuance of common stock	34	—	—	34
Proceeds from issuance of long-term debt	136	—	—	136
Common stock dividends paid	(228)	—	228	—
BGE preference stock dividends paid	(13)	(13)	—	—
Proceeds from contract and portfolio acquisitions	2,263	—	—	2,263
Repayment of long-term debt	(1,987)	(90)	—	(1,897)
Derivative contracts classified as financing activities	(1,138)	—	—	(1,138)
Debt and credit facility costs	(98)	(1)	—	(97)
Contribution from parent	—	316	316	—
Contribution to parent	—	—	(544)	(544)
Other	12	8	—	4
Net cash (used in) financing activities	(1,829)	(104)	—	(1,725)
Net Increase in Cash and Cash Equivalents	3,238	3	—	3,235
Cash and Cash Equivalents at Beginning of Year	202	11	—	191
Cash and Cash Equivalents at End of Year	$ 3,440	$ 14	$ —	$ 3,426

Exhibit 99.2

UNAUDITED PRO FORMA CONDENSED COMBINED CONSOLIDATED FINANCIAL STATEMENTS

On March 12, 2012, Exelon Corporation (Exelon) completed the merger contemplated by the Agreement and Plan of Merger, dated as of April 28, 2011, among Exelon, Constellation Energy Group, Inc. (Constellation) and Bolt Acquisition Corporation, formerly a Maryland corporation and wholly owned subsidiary of Exelon (Merger Sub). As a result of that merger, Merger Sub was merged into Constellation (the Initial Merger) and Constellation became a wholly owned subsidiary of Exelon. Following the completion of the Initial Merger, Exelon and Constellation completed a series of internal corporate organizational restructuring transactions. Constellation merged with and into Exelon, with Exelon continuing as the surviving corporation (the Upstream Merger). Simultaneously with the Upstream Merger, Constellation's interest in RF Holdco LLC, which held Constellation's interest in Baltimore Gas and Electric Company (BGE), was transferred to Exelon Energy Delivery Company, LLC, a wholly owned subsidiary of Exelon that also owns Exelon's interest in Commonwealth Edison Company (ComEd) and PECO Energy Company (PECO). Following the Upstream Merger and the transfer of RF Holdco LLC, Exelon contributed to Exelon Generation Company, LLC (Generation) certain subsidiaries, including the generation and customer supply businesses that were acquired from Constellation as a result of the Initial Merger and the Upstream Merger.

Constellation's shareholders received 0.930 shares of Exelon common stock in exchange for each share of Constellation common stock outstanding as of March 12, 2012. Generally, all outstanding Constellation equity-based compensation awards were converted into Exelon equity-based compensation awards using the same ratio.

All options to purchase Constellation common stock under various equity agreements were converted into options to acquire a number of shares of Exelon common stock (as adjusted for the exchange ratio) at an option price (as adjusted for the exchange ratio). All Constellation unvested restricted stock awards granted prior to April 28, 2011, that were outstanding immediately prior to the consummation of the Initial Merger, became vested on a pro rata basis (determined based upon the number of months from the start of the applicable restricted period to the closing of the Initial Merger) and converted into Exelon common stock at the exchange ratio in accordance with the applicable stock plan and award agreement terms. All Constellation restricted stock awards that remained unvested on a pro rata basis pursuant to the foregoing formula, and any Constellation unvested restricted stock awards granted after April 28, 2011, were assumed by Exelon and automatically converted into shares of unvested restricted stock of Exelon at the exchange ratio. Likewise, all Constellation restricted stock units granted prior to April 28, 2011 and outstanding immediately prior to the completion of the Initial Merger became vested on a pro rata basis (determined based upon the number of months from the start of the applicable restricted period to the closing of the Initial Merger) and were assumed by Exelon and automatically converted into a number of shares of Exelon common stock at the exchange ratio.

The conversion of stock-based awards granted under the Constellation equity plans and held by Constellation employees that were generally converted into outstanding Exelon stock-based compensation awards had an estimated fair value of $71 million. Specifically, as of the Initial Merger closing: (1) Exelon converted 12,037,093 outstanding shares that were subject to Constellation stock options into 11,194,151 Exelon stock options valued at $65 million; and (2) Exelon converted 165,219 Constellation no-sale restricted stock units into 153,654 Exelon no-sale restricted stock units valued at $6 million.

The Unaudited Pro Forma Condensed Combined Consolidated Financial Statements (referred to as the pro forma financial statements) combine the historical consolidated financial statements of Exelon and Constellation to illustrate the effect of the Initial Merger and the Upstream Merger (collectively, the mergers). The pro forma financial statements were based on and should be read in conjunction with the:

- accompanying notes to the Unaudited Pro Forma Condensed Combined Consolidated Financial Statements;
- consolidated financial statements of Exelon and Generation for the year ended December 31, 2011 and for the three months ended March 31, 2012 and the notes relating thereto which are included in Exelon's Annual Report on Form 10-K for the year ended December 31, 2011 in Item 8, FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA, beginning at page 174, and from Exelon's Quarterly Report on Form 10-Q for the quarter ended March 31, 2012 in Part 1. FINANCIAL INFORMATION, Item 1. Financial Statements, beginning at page 8, respectively; and
- consolidated financial statements of Constellation and BGE for the year ended December 31, 2011 and the notes relating thereto, attached as Exhibit 99.1.

The historical consolidated financial statements have been adjusted in the pro forma financial statements to give effect to pro forma events that are (1) directly attributable to the mergers, (2) factually supportable and (3) expected to have a continuing impact on the combined results. The Unaudited Pro Forma Condensed Combined Consolidated Statements of Operations (which we refer to as the pro forma statements of operations) for the year ended December 31, 2011 and for the three months ended March 31, 2012, give effect to the mergers as if they occurred on January 1, 2011. The pro forma financial statements do not include a pro forma balance sheet as the mergers are reflected in the most recent historical balance sheets filed in the financial statements of Exelon and Generation for the three months ended March 31, 2012 and the notes relating thereto.

As described in the accompanying notes, the pro forma financial statements have been prepared using the acquisition method of accounting under existing United States generally accepted accounting principles, or GAAP, and the regulations of the SEC.

The pro forma financial statements have been presented for informational purposes only and are not necessarily indicative of what the combined company's results of operations and financial position would have been had the mergers been completed on the date indicated. In addition, the pro forma financial statements do not purport to project the future results of operations or financial position of the combined company. The pro forma financial statements do not reflect any cost savings (or associated costs to achieve such savings) from operating efficiencies, synergies or other actions that are expected to result from the mergers.

Assumptions and estimates underlying the pro forma adjustments are described in the accompanying notes, which should be read in conjunction with the pro forma financial statements. The initial accounting for the mergers is not complete because the valuations necessary to assess the fair values of certain assets acquired and liabilities assumed are considered preliminary as a result of the short time period between the closing of the mergers and the filing of these pro forma financial statements. The preliminary amounts recognized are subject to revision until the valuations are completed and to the extent that additional information is obtained about the facts and circumstances that existed as of the acquisition date. Any changes to the fair value assessments may affect the purchase price allocation and material changes could require the financial statements to be retroactively amended. See Note 3 — Purchase Price and Preliminary Purchase Price Allocation of the Notes to the Unaudited Pro Forma Condensed Combined Consolidated Financial Statements for additional information.

EXELON CORPORATION
UNAUDITED PRO FORMA CONDENSED COMBINED CONSOLIDATED STATEMENT OF OPERATIONS
For the Three Months Ended March 31, 2012
(in millions, except per share data)

	Exelon Historical (unaudited)	Constellation Historical (unaudited) (a)	Pro Forma Adjustments		Pro Forma Combined	
Operating revenues	$ 4,686	$ 2,400	$ —	(b)	$ 7,113	
			(86)	(d)		
			113	(k)		
Operating expenses						
Purchased power and fuel	1,765	1,677	—	(b)	3,413	
			(29)	(d)		
Operating and maintenance	1,964	417	(156)	(j)	1,983	
			(217)	(k)		
			(25)	(l)		
Depreciation, amortization, depletion and accretion	382	124	(1)	(c)	497	
			(1)	(d)		
			10	(g)		
			(17)	(o)		
Taxes other than income	194	61	—		255	
Total operating expenses	4,305	2,279	(436)		6,148	
Equity in loss of unconsolidated affiliates	(22)	(15)	(4)	(e)	(42)	
			(1)	(f)		
Operating income	359	106	458		923	
Other income and deductions						
Interest expense	(189)	(58)	14	(h)	(233)	
Interest expense to affiliates, net	(6)	—	—		(6)	
Other, net	194	(14)	—		180	
Total other income and deductions	(1)	(72)	14		(59)	
Income before income taxes	358	34	472		864	
Income taxes	158	32	189	(m)	379	
Net income	200	2	283		485	
Net income attributable to noncontrolling interest and preferred security dividends	—	(5)	—		(5)	
Net income attributable to common stock	200	7	283		490	
Average shares of common stock outstanding:						
Basic	705				849	(n)
Diluted	707				851	(n)
Earnings per average common share:						
Basic	$ 0.28	$ —			$ 0.58	
Diluted	$ 0.28	$ —			$ 0.58	

See accompanying Notes to the Unaudited Pro Forma Condensed Combined Consolidated Financial Statements, which are an integral part of these statements.

EXELON CORPORATION
UNAUDITED PRO FORMA CONDENSED COMBINED CONSOLIDATED
STATEMENT OF OPERATIONS
For the Year Ended December 31, 2011
(in millions, except per share data)

	Exelon Historical (a)	Constellation Historical (a)	Pro Forma Adjustments		Pro Forma Combined	
Operating revenues	$ 19,063	$ 13,729	$ (330)	(b)	$ 30,934	
			(1,528)	(d)		
Operating expenses						
Purchased power and fuel	7,267	10,256	(330)	(b)	16,371	
			(822)	(d)		
Operating and maintenance	5,196	1,902	(195)	(j)	6,903	
Depreciation, amortization, depletion and accretion	1,335	589	(26)	(c)	1,848	
			(1)	(d)		
			41	(g)		
			1	(i)		
			(91)	(o)		
Impairment losses and other costs	—	891	—		891	
Taxes other than income	785	308	—		1,093	
Total operating expenses	14,583	13,946	(1,423)		27,106	
Equity investment earnings (losses) of unconsolidated affiliates	(1)	20	(31)	(e)	(17)	
			(5)	(f)		
Operating income	4,479	(197)	(471)		3,811	
Other income and deductions						
Interest expense	(701)	(260)	54	(h)	(907)	
Interest expense to affiliates, net	(25)	—	—		(25)	
Other, net	199	(75)	—		124	
Total other income and deductions	(527)	(335)	54		(808)	
Income (loss) before income taxes	3,952	(532)	(417)		3,003	
Income taxes expense (benefit)	1,457	(225)	(167)	(m)	1,065	
Net income (loss)	2,495	(307)	(250)		1,938	
Net income attributable to noncontrolling interest and preferred security dividends	—	33	—		33	
Net income (loss) attributable to common stock	2,495	(340)	(250)		1,905	
Average shares of common stock outstanding:						
Basic	663	200	(14)	(n)	849	(n)
Diluted	665	200	(14)	(n)	851	(n)
Earnings per average common share:						
Basic	$ 3.76	$ (1.70)			$ 2.24	
Diluted	$ 3.75	$ (1.70)			$ 2.24	

See accompanying Notes to the Unaudited Pro Forma Condensed Combined Consolidated Financial Statements, which are an integral part of these statements.

EXELON GENERATION COMPANY, LLC
UNAUDITED PRO FORMA CONDENSED COMBINED CONSOLIDATED
STATEMENT OF OPERATIONS
For the Three Months Ended March 31, 2012
(in millions)

	Generation Historical (unaudited)	Nonregulated Constellation Historical (unaudited) (a)	Pro Forma Adjustments		Pro Forma Combined
Operating revenues	$ 2,373	$ 1,846	$ (86)	(d)	$ 4,133
Operating revenues from affiliates	366	—	32	(b)	398
Operating expenses					
Purchased power and fuel	1,044	1,451	32	(b)	2,498
			(29)	(d)	
Operating and maintenance	1,039	283	(75)	(j)	1,194
			(35)	(k)	
			(18)	(l)	
Operating and maintenance from affiliates	136	—	—		136
Depreciation, amortization, depletion and accretion	153	63	(1)	(c)	207
			(1)	(d)	
			10	(g)	
			(17)	(o)	
Taxes other than income	73	22	—		95
Total operating expenses	2,445	1,819	(134)		4,130
Equity in loss of unconsolidated affiliates	(22)	(15)	(4)	(e)	(42)
			(1)	(f)	
Operating income	272	12	75		359
Other income and deductions					
Interest expense	(54)	(26)	13	(h)	(67)
Other, net	178	(17)	—		161
Total other income and deductions	124	(43)	13		94
Income before income taxes	396	(31)	88		453
Income taxes	230	2	35	(m)	267
Net income	166	(33)	53		186
Net income attributable to noncontrolling interest	(2)	(7)	—		(9)
Net income attributable to common stock	168	(26)	53		195

See accompanying Notes to the Unaudited Pro Forma Condensed Combined Consolidated Financial Statements, which are an integral part of these statements.

EXELON GENERATION COMPANY, LLC
UNAUDITED PRO FORMA CONDENSED COMBINED CONSOLIDATED
STATEMENT OF OPERATIONS
For the Year Ended December 31, 2011
(in millions)

	Generation Historical (a)	Nonregulated Constellation Historical (a)	Pro Forma Adjustments		Pro Forma Combined
Operating revenues	$ 9,286	$ 11,084	$ (330)	(b)	$ 18,512
			(1,528)	(d)	
Operating revenues from affiliates	1,161	—	261	(b)	1,422
Operating expenses					
Purchased power and fuel	3,589	9,085	(69)	(b)	11,783
			(822)	(d)	
Operating and maintenance	2,827	1,205	(165)	(j)	3,867
Operating and maintenance from affiliates	321	—	—		321
Depreciation, amortization, depletion and accretion	570	317	(26)	(c)	810
			(1)	(d)	
			41	(g)	
			(91)	(o)	
Impairment losses and other costs	—	891	—		891
Taxes other than income	264	118	—		382
Total operating expenses	7,571	11,616	(1,133)		18,054
Equity investment earnings (losses) of unconsolidated affiliates	(1)	20	(31)	(e)	(17)
			(5)	(f)	
Operating income	2,875	(512)	(500)		1,863
Other income and deductions					
Interest expense	(170)	(132)	50	(h)	(252)
Other, net	122	(97)	—		25
Total other income and deductions	(48)	(229)	50		(227)
Income (loss) before income taxes	2,827	(741)	(450)		1,636
Income taxes expense (benefit)	1,056	(298)	(180)	(m)	578
Net income (loss)	1,771	(443)	(270)		1,058
Net income attributable to noncontrolling interest	—	20	—		20
Net income (loss) attributable to common stock	1,771	(463)	(270)		1,038

See accompanying Notes to the Unaudited Pro Forma Condensed Combined Consolidated Financial Statements, which are an integral part of these statements.

EXELON AND CONSTELLATION
NOTES TO THE UNAUDITED PRO FORMA
CONDENSED COMBINED CONSOLIDATED FINANCIAL STATEMENTS

Note 1. Basis of Pro Forma Presentation

The pro forma financial statements were derived from historical consolidated financial statements of Exelon, Generation and Constellation for the three months ended March 31, 2012 and the year ended December 31, 2011. Certain reclassifications have been made to the historical financial statements of Constellation to conform with Exelon's and Generation's presentation. This resulted in income statement adjustments to operating revenues, operating expenses, other income and deductions, and income taxes.

The historical consolidated financial statements have been adjusted in the pro forma financial statements to give effect to pro forma events that are (1) directly attributable to the mergers, (2) factually supportable, and (3) expected to have a continuing impact on the combined results. The following matters have not been reflected in the pro forma financial statements as they do not meet the aforementioned criteria.

- Cost savings (or associated costs to achieve such savings) from operating efficiencies, synergies or other restructuring that have not yet been incurred and reflected in the historical financial statements, and that could result from the mergers. The timing and effect of actions associated with integration are currently uncertain.
- Other than depreciation and amortization expense, adjustments to eliminate the operating revenues and expenses directly associated with Constellation's Brandon Shores, H.A. Wagner and C.P. Crane generation plants that Generation agreed to enter into contracts to sell within 150 days following the completion of the mergers to mitigate market power in PJM Interconnection, LLC (PJM), given the specifically identifiable revenues related to the plants are not determinable. Exelon and Generation have excluded the depreciation and amortization expense recorded for these assets prior to the merger from the pro forma statements of operations. See Note 4—Pro Forma Adjustments to Financial Statements for additional information.
- Any fair value adjustments for revenues and expenses subject to rate-setting provisions for Constellation's regulated utility, BGE. BGE is comprised of electric transmission and distribution and gas distribution operations. These operations are subject to the rate-setting authority of the Federal Energy Regulatory Commission and the Public Service Commission of Maryland and are accounted for pursuant to GAAP, including the accounting guidance for regulated operations. The rate-setting and cost recovery provisions currently in place for Constellation's regulated operations provide revenues derived from costs including a return on investment of assets and liabilities included in rate base. Except for debt and regulatory assets not earning a return as further described in Note 4—Pro Forma Adjustments to Financial Statements, the fair values of Constellation's tangible and intangible assets and liabilities subject to these rate-setting provisions are assumed to approximate their carrying values and, therefore the pro forma statements of operations do not reflect any adjustments related to the revenues and expenses of BGE.
- Exelon's and Generation's commitment to cause construction of a headquarters building in Baltimore for Generation's competitive energy business, or commitment to develop 285 — 300 MW of new generation in Maryland, expected to be completed over a period of 10 years. As of March 31, 2012, no amounts have been reflected in the Exelon or Generation consolidated financial statements for these expenditure commitments. Such costs, which are expected to be primarily capital in nature, will be recognized as incurred. Given the information available as of the filing of this document, Exelon and Generation cannot estimate the expense it will incur related to these commitments. Other regulatory commitments were expensed in the consolidated financial statements of Exelon and Generation for the three months ended March 31, 2012. The related pro forma adjustments are described in Note 4—Pro Forma Adjustments to Financial Statements.

The pro forma financial statements were prepared using the acquisition method of accounting under GAAP and the regulations of the SEC. Exelon and Generation have been treated as the acquirer in the mergers for accounting purposes. Acquisition accounting requires, among other things, that most assets acquired and liabilities assumed be recognized at fair value as of the acquisition date. In addition, acquisition accounting establishes that the consideration transferred be measured at the closing date of the merger at the then-current market price. The initial accounting for the mergers is not complete because the valuations necessary to assess the fair values of certain assets acquired and liabilities assumed are considered preliminary as a result of the short time period between the closing of the mergers and the filing of the pro forma financial statements. The preliminary amounts recognized are subject to revision until the valuations are completed and to the extent that additional information is obtained about the facts and circumstances that existed as of the acquisition date; Exelon and Generation expect to finalize these amounts by the end of 2012, if not sooner. Differences between these preliminary estimates and the final acquisition accounting will occur and these differences could have a material impact on the accompanying pro forma financial statements and the combined company's future results of operations and financial position. See Note 3—Purchase Price and Preliminary Purchase Price Allocation for additional information.

Note 2. Significant Accounting Policies

Exelon is not aware of any differences in accounting policies that would have a material impact on the combined financial statements. The pro forma financial statements do not assume any differences in accounting policies.

Note 3. Purchase Price and Preliminary Purchase Price Allocation

Exelon acquired all of the outstanding shares of Constellation's common stock for shares of Exelon common stock at the fixed exchange ratio of 0.930 of a share of Exelon common stock per share of Constellation's common stock. The total consideration transferred was based on the opening price of a share of Exelon common stock on March 12, 2012 (in millions except conversion ratio and share price):

	Number of Shares/ Awards Issued	Total Estimated Fair Value
Issuance of Exelon common stock to Constellation stockholders at the exchange ratio of 0.930 shares for each share of Constellation common stock; based on the opening price of Exelon common stock on March 12, 2012 of $38.91 (a)	187.45	$7,294
Issuance of Exelon equity awards to replace existing Constellation equity awards (b)	11.30	71
Total estimated purchase price		$7,365

(a) The number of shares issued excludes 0.7 million shares of stock that are held in a custodian account specifically for the settlement of unvested share-based restricted stock awards. The related share value is excluded from the estimated fair value as these awards have not vested and therefore are not in the purchase price.

(b) Includes vested Constellation stock options and restricted stock units converted at fair value to Exelon awards on March 12, 2012. The fair value of the stock options was determined using the Black-Scholes model.

The purchase price was computed using Constellation's outstanding shares as of March 12, 2012, adjusted for the exchange ratio. The purchase price reflects the market value of Exelon's common stock issued in connection with the Initial Merger based on the opening price of a share of Exelon common stock on March 12, 2012. The purchase price also reflects the total estimated fair value of Constellation's share-based compensation awards outstanding as of March 12, 2012, excluding the value associated with employee service yet to be rendered.

The allocation of the purchase price to the fair values of assets acquired and liabilities assumed includes pro forma adjustments to reflect the fair values of Constellation's assets and liabilities at the time of the completion of the mergers. The final allocation of the purchase price could differ materially from the preliminary allocation used for the pro form financial statements as the valuations are not complete.

The preliminary purchase price allocation of the Initial Merger of Exelon with Constellation and Exelon's contribution of certain subsidiaries of Constellation to Generation was as follows:

Preliminary Purchase Price Allocation	Exelon	Generation
Current assets	$ 4,944	$ 3,649
Property, plant and equipment	9,295	3,993
Unamortized energy contracts	3,624	3,624
Other assets, trade name and retail relationships	456	456
Investment in affiliates	2,067	2,067
Pension and OPEB regulatory asset	740	—
Other assets	2,612	1,210
Total assets	23,738	14,999

Current liabilities	3,480	2,866
Unamortized energy contracts	2,268	2,062
Long-term debt, including current maturities	5,632	2,972
Noncontrolling interest	85	85
Deferred credits and other liabilities and preferred securities	4,908	1,742
Total liabilities, preferred securities and noncontrolling interest	16,373	9,727
Total purchase price	$ 7,365	$5,272

Intangible Assets Recorded

For the power supply and fuel accrual-based contracts acquired from Constellation, the difference between the contract price and the market price at the date of the merger was recognized as either an intangible asset or liability based on whether the accrual-based contracts were in or out-of-the-money. The valuation of the acquired intangible assets/liabilities was estimated by applying either the market approach or the income approach depending on the nature of the underlying contract. The market approach was utilized when prices and other relevant information generated by market transactions involving comparable transactions were available. Otherwise the income approach, which is based upon discounted projected future cash flows associated with the underlying contracts, was utilized. The measure is based upon certain unobservable inputs, which are considered Level 3 inputs, pursuant to applicable accounting guidance. Key estimates and inputs include forecasted power and fuel prices and the discount rate. These intangible assets and liabilities will be amortized over the life of the contract in relation to the present value of the underlying cash flows. Amortization expense and income will be recorded through operating revenues or purchased power and fuel expense, respectively. The weighted-average amortization period is approximately 2 years.

The fair value of the Constellation trade name intangible asset was determined based on the relief from royalty method of the income approach whereby fair value is the present value of the license fees avoided by owning the assets. The measure is based upon certain unobservable inputs, which are considered Level 3 inputs, pursuant to applicable accounting guidance. Key assumptions include the hypothetical royalty rate and the discount rate. The intangible asset will be amortized on a straight line basis over an estimated ten year useful life as amortization expense.

The fair value of the retail relationships was determined based on a “multi-period excess method” of the income approach. Under this method, the intangible asset’s fair value is equal to the estimated future cash flows that will be earned on the current customer base, taking into account expected contract renewals based on customer attrition rates and costs to retain those customers. The measure is based upon certain unobservable inputs, which are considered Level 3 inputs, pursuant to applicable accounting guidance. Key assumptions include the customer attrition rate and the discount rate. The intangible assets will be amortized on a straight line based over the useful life of the underlying assets averaging approximately 12 years.

Exelon’s acquired intangible assets and liabilities included in its Consolidated Balance Sheets, along with the future estimated amortization, were as follows as of March 31, 2012:

					Estimated amortization expense				
Description	Weighted Average Amortization	Gross	Accumulated Amortization	Net	Remainder of 2012	2013	2014	2015	2016
Unamortized energy contracts, net (a)	1.5	$1,356	$ (122)	$1,234	$ 804	$340	$52	$18	$(25)
Trade name	10.0	243	(2)	241	22	24	24	24	24
Retail relationships	11.8	213	(1)	212	19	21	20	19	19
Total, net		$1,812	$ (125)	$1,687	$ 845	$385	$96	$61	$ 18

(a) Includes the fair value of the liability for BGE’s power and gas supply contracts of $206 million, for which an offsetting regulatory asset was also recorded. Except for this liability, all other acquired intangible assets and liabilities were recorded on Generation’s Consolidated Balance Sheets.

Note 4. Pro Forma Adjustments to Financial Statements

The pro forma adjustments included in the pro forma financial statements are as follows:

(a) Exelon, Generation and Constellation historical presentation – Certain financial statement line items included in Exelon’s, Generation’s and Constellation’s historical presentation have been reclassified between line items. These reclassifications had no impact on the historical operating income or net income reported by Exelon, Generation or Constellation. In addition, Constellation’s historical presentation in the pro forma statement of operations for the three months ended March 31, 2012 represents the activity from January 1, 2012 through the effective time of the merger.

(b) *Intercompany Transactions* – The pro forma statements of operations for Exelon and Generation include pro forma adjustments to eliminate transactions between Exelon and Constellation, and between Generation and Nonregulated Constellation, respectively, included in each company's historical financial statements, primarily for purchases and sales of energy between the companies.

	Exelon		Generation	
Unaudited Pro Forma Combined Consolidated Statement of Operations (in millions)	Three Months Ended March 31, 2012	Year Ended December 31, 2011	Three Months Ended March 31, 2012	Year Ended December 31, 2011
Operating revenues	$ —	$ (330)	$ 32	$ (330)
Operating revenues from affiliates				261
Operating expenses				
Purchased power and fuel	—	(330)	32	(69)
Pro forma statement of operations adjustment	$ —	$ —	$ —	$ —

(c) *Nonregulated Property, Plant and Equipment* – The pro forma statements of operations for Exelon and Generation include the pro forma adjustments to reflect the decrease in depreciation and depletion expense resulting from the fair valuation adjustment to Constellation's nonregulated generating assets, resulting in net decreased depreciation expense of $1 million and $26 million for the three months ended March 31, 2012 and the year ended December 31, 2011, respectively. These estimates are preliminary, subject to change and could vary materially from the actual adjustment until the valuations are completed. The estimated useful life of Constellation's property, plant and equipment ranges from 10 to 44 years.

(d) *Power Supply and Fuel Contracts* – The pro forma statements of operations include pro forma adjustments to reflect the net reduction in operating revenues for sales and a reduction in purchased power expense for purchases resulting from the amortization of the fair valuation adjustment related to Constellation's non-derivative energy and fuel contracts. The pro forma statements of operations for Exelon and Generation include a reduction of operating revenues of $86 million and $1,528 million and a reduction in purchased power expense of $29 million and $822 million for the three months ended March 31, 2012 and the year ended December 31, 2011, respectively, and a reduction of amortization expense of $1 million for the three months ended March 31, 2012 and the year ended December 31, 2011. These estimates are preliminary, subject to change and could vary materially from the actual adjustments at the time the valuations are completed.

(e) *Investments in Affiliates* – The pro forma statements of operations for Exelon and Generation include the pro forma adjustments reflecting increases in the basis difference amortization of $4 million and $31 million for the three months ended March 31, 2012 and the year ended December 31, 2011, respectively. The basis difference represents the difference between the carrying amount and fair value of Constellation's investment in CENG. The basis difference is amortized over the respective useful lives of the assets and liabilities of CENG or as CENG's assets and liabilities impact the earnings of CENG.

(f) *Other Investments* – The pro forma statements of operations for Exelon and Generation include the pro forma adjustments for the basis difference amortization for the fair value of Constellation's investment in a hydroelectric generation facility of $1 million and $5 million for the three months ended March 31, 2012 and the year ended December 31, 2011, respectively. The basis difference represents the difference between the carrying amount and fair value of Constellation's investment and is assumed to be amortized straight line over a term of 40 years based on the anticipated life of the asset.

(g) *Intangible Assets* – The pro forma statements of operations for Exelon and Generation include the pro forma adjustments to reflect the net incremental amortization resulting from the pro forma fair valuation of Constellation NewEnergy's trade names and customer relationships of $10 million and $41 million for the three months ended March 31, 2012 and the year ended December 31, 2011, respectively. The trade name and customer relationships intangible assets are assumed to be amortized straight line over their useful lives, which range from 5 to 15 years.

(h) *Debt* – The pro forma statements of operations include pro forma adjustments to reflect the net reduction in interest expense resulting from the fair valuation of Constellation's third-party debt of $12 million and $47 million for Exelon and Generation for the three months ended March 31, 2012 and the year ended December 31, 2011, respectively. In addition, the pro forma statements of operations include pro forma adjustments to reflect the elimination of the amortization of Constellation's deferred debt issuance and credit facility costs of $2 million and $7 million recorded in interest expense for Exelon for the three months ended March 31, 2012 and the year ended December 31, 2011, respectively, and $1 million and $3 million for Generation for the three months ended March 31, 2012 and the year ended December 31, 2011, respectively.

(i) *Regulatory Assets* – The Exelon pro forma statement of operation includes the pro forma adjustments to reflect the amortization expense resulting from the pro forma fair valuation of BGE's regulatory assets not earning a return of $1 million for the year ended December 31, 2011. The fair valuation adjustment is assumed to be amortized straight line over a term of 7 years based on the current expected recovery period of the associated regulatory assets.

(j) *Merger Transaction Costs* – The Exelon pro forma statements of operations include the pro forma adjustments to eliminate the merger transaction costs incurred by Exelon and Constellation of $156 million and $195 million for the three months ended March 31, 2012 and the year ended December 31, 2011, respectively. The Generation pro forma statements of operations include the pro forma adjustments to eliminate the merger transaction costs incurred by Generation and Nonregulated Constellation of $75 million and $165 million for the three months ended March 31, 2012 and the year ended December 31, 2011, respectively. The merger transaction costs consisted of investment banking fees, legal fees, and employee-related costs directly attributable to the mergers and other merger-related transaction costs. These costs have been excluded from the pro forma statements of operations as they reflect non-recurring charges not expected to have a continuing impact on the combined results.

(k) *Regulatory Commitments* – The pro forma statement of operations for the three months ended March 31, 2012 includes a pro forma adjustment to exclude costs related to commitments promised in the settlement agreements, and a pro forma adjustment to include revenue that was eliminated related to BGE rate credit of $100 per residential customer, as these adjustments are directly attributable to the mergers and reflect non-recurring charges not expected to have a continuing impact on the combined results. The following pre-tax costs were excluded from the pro forma statement of operations for the three months ended March 31, 2012:

Description	Expected Payment Period	BGE	Generation	Exelon	Statement of Operations Location
BGE rate credit of $100 per residential customer	Q2 2012	$113	$ —	$ 113	Revenues
Customer investment fund to invest in energy efficiency and low-income energy assistance to BGE customers	2012 to 2014	—	—	113	O&M Expense
Contribution for renewable energy, energy efficiency or related projects in Baltimore	2012 to 2014	—	—	2	O&M Expense
Charitable contributions at $7 million per year for 10 yrs	2012 to 2021	28	35	70	O&M Expense
State funding for offshore wind development projects	Q2 2012	—	—	32	O&M Expense
Total		$141	$ 35	$ 330	

(l) *Share-based Compensation* – Each Constellation share award was converted as described above. The authoritative guidance for accounting for business combinations requires that the fair value of replacement awards and cash payments made to settle vested awards attributable to pre-combination service be included in the determination of the purchase price. Accordingly, the fair value of Constellation share-based awards which immediately vested at the effective time of the Initial Merger has been attributed to pre-combination service and reflected in purchase price. For unvested Constellation share-based awards converted to unvested Exelon awards at the effective time of the Initial Merger, the future compensation expense is consistent with the compensation expense recorded in Constellation's historical income statements. For unvested Constellation share-based awards that were immediately vested at the effective time of the Initial Merger, the Exelon pro forma statement of operations for the three months ended March 31, 2012 includes the pro forma adjustment of $25 million and the Generation pro forma statement of operations for the three months ended March 31, 2012 includes the pro forma adjustment of $18 million to exclude expense related to the acceleration. These costs have been excluded from the pro forma statements of operations as they reflect non-recurring charges directly attributable to the transaction.

(m) *Income Taxes* – The pro forma statements of operations include the pro forma adjustments to reflect the tax effects of the pro forma adjustments based on an estimated prospective statutory tax rate of 40% for the combined company. The estimated prospective statutory tax rate of 40% could change based on future changes in the applicable tax rates and final determination of the combined company's tax position.

(n) *Common Stock Shares outstanding* – Reflects the elimination of the Constellation common stock offset by issuance of 187 million shares of Exelon common stock. The pro forma weighted average number of basic shares outstanding is calculated by adding Exelon's weighted average number of basic shares of common stock outstanding for the year ended December 31, 2011, as applicable, and Constellation's weighted average number of basic shares of common stock outstanding for the same period multiplied by the exchange ratio of 0.930. The following table illustrates these computations (in millions except conversion ratio):

Description	Three Months Ended March 31, 2012	Year Ended December 31, 2011
Basic:		
Constellation weighted average basic common shares	200	200
Conversion ratio	0.930	0.930
Equivalent Exelon common shares	186	186
Exelon weighted average basic common shares	663	663
Pro forma weighted average basic common shares	849	849
Diluted:		
Constellation weighted average diluted common shares	200	200
Conversion ratio	0.930	0.930
Equivalent Exelon common shares	186	186
Exelon weighted average diluted common shares	665	665
Pro forma weighted average diluted common shares	851	851

(o) *Assets Held for Sale* – Reflects the elimination of the depreciation and amortization expense directly associated with Constellation's Brandon Shores, H.A. Wagner and C.P. Crane generation plants that Generation has committed to sell within 150 days following the completion of the mergers to mitigate market power in PJM of $17 million for the three months ended March 31, 2012 and $91 million for the year ended December 31, 2011.