BALTIMORE GAS & ELECTRIC CO
Form 10-Q
August 06, 2010

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

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

For The Quarterly Period Ended **June 30, 2010**

Commission File Number	Exact name of registrant as specified in its charter	IRS Employer Identification No.
1-12869	**CONSTELLATION ENERGY GROUP, INC.**	**52-1964611**

100 CONSTELLATION WAY, BALTIMORE, MARYLAND 21202
(Address of principal executive offices) (Zip Code)

410-470-2800
(Registrant's telephone number, including area code)

1-1910	**BALTIMORE GAS AND ELECTRIC COMPANY**	**52-0280210**

2 CENTER PLAZA, 110 WEST FAYETTE STREET, BALTIMORE, MARYLAND 21202
(Address of principal executive offices) (Zip Code)

410-234-5000
(Registrant's telephone number, including area code)

MARYLAND
(State of Incorporation of both registrants)

NOT APPLICABLE
(Former name, former address and former fiscal year, if changed since last report)

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months, and (2) have been subject to such filing requirements for the past 90 days. Yes ý No o

Indicate by check mark whether Constellation Energy Group, Inc. has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for

such shorter period that the registrant was required to submit and post such files). Yes ý No o

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

Indicate by check mark whether Constellation Energy Group, Inc. is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.
(Check one):

Large accelerated filer ý	Accelerated filer o	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

Indicate by check mark whether Baltimore Gas and Electric Company is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.
(Check one):

Large accelerated filer o	Accelerated filer o	Non-accelerated filer ý (Do not check if a smaller reporting company)	Smaller reporting company o

Indicate by check mark whether Constellation Energy Group, Inc. is a shell company (as defined in Rule 12b-2 of the Exchange Act) Yes o No ý

Indicate by check mark whether Baltimore Gas and Electric Company is a shell company (as defined in Rule 12b-2 of the Exchange Act) Yes o No ý

Common Stock, without par value 201,961,349 shares outstanding of Constellation Energy Group, Inc. on July 30, 2010.

Baltimore Gas and Electric Company meets the conditions set forth in General Instruction H(1)(a) and (b) of Form 10-Q and is therefore filing this form in the reduced disclosure format.

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PART 1 FINANCIAL INFORMATION

Item 1 Financial Statements

CONSOLIDATED STATEMENTS OF INCOME (LOSS) (UNAUDITED)

Constellation Energy Group, Inc. and Subsidiaries

	Three Months Ended June 30,		*Six Months Ended June 30,*	
	2010	**2009**	**2010**	**2009**
	(In millions, except per share amounts)			
Revenues				
Nonregulated revenues	**$ 2,559.2**	$ 3,097.3	**$ 5,077.4**	$ 6,209.6
Regulated electric revenues	**651.1**	655.7	**1,402.4**	1,462.5
Regulated gas revenues	**99.6**	111.1	**416.7**	495.4
Total revenues	**3,309.9**	3,864.1	**6,896.5**	8,167.5
Expenses				
Fuel and purchased energy expenses	**2,267.7**	2,631.6	**4,629.8**	5,904.8
Fuel and purchased energy expenses from affiliate	**222.1**		**420.6**	
Operating expenses	**413.7**	561.2	**810.1**	1,142.9
Merger termination and strategic alternatives costs		4.0		46.3
Impairment losses and other costs		67.2		95.8
Workforce reduction costs		0.4		11.2
Depreciation, depletion, and amortization	**125.3**	148.9	**256.7**	297.5
Accretion of asset retirement obligations	**0.4**	18.2	**0.9**	36.1
Taxes other than income taxes	**65.6**	72.4	**132.4**	150.3
Total expenses	**3,094.8**	3,503.9	**6,250.5**	7,684.9
Equity Investment Losses	**(33.5)**		**(54.2)**	
Net Gain (Loss) on Divestitures	**0.3**	(129.6)	**5.2**	(464.1)
Income from Operations	**181.9**	230.6	**597.0**	18.5
Other Expenses	**(8.9)**	(15.0)	**(31.2)**	(71.3)
Fixed Charges				
Interest expense	**60.4**	106.1	**181.9**	221.2
Interest capitalized and allowance for borrowed funds used during construction	**(8.7)**	(21.6)	**(24.3)**	(43.2)
Total fixed charges	**51.7**	84.5	**157.6**	178.0
Income (Loss) from Continuing Operations Before Income Taxes	**121.3**	131.1	**408.2**	(230.8)
Income Tax Expense (Benefit)	**37.5**	102.8	**133.1**	(139.4)
Net Income (Loss)	**83.8**	28.3	**275.1**	(91.4)
Less: Net Income Attributable to Noncontrolling Interests and BGE Preference Stock Dividends	**11.2**	20.2	**11.0**	24.0
Net Income (Loss) Attributable to Common Stock	**$ 72.6**	$ 8.1	**$ 264.1**	$ (115.4)
Average Shares of Common Stock Outstanding Basic	**200.8**	199.2	**200.6**	198.9
Average Shares of Common Stock Outstanding Diluted	**202.6**	200.0	**202.2**	198.9
Earnings (Loss) Per Common Share Basic	**$ 0.36**	$ 0.04	**$ 1.32**	$ (0.58)

Earnings (Loss) Per Common Share Diluted	**$ 0.36**	$ 0.04	**$ 1.31**	$ (0.58)
Dividends Declared Per Common Share	**$ 0.24**	$ 0.24	**$ 0.48**	$ 0.48

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

Constellation Energy Group, Inc. and Subsidiaries

	Three Months Ended June 30,		*Six Months Ended June 30,*	
	2010	**2009**	**2010**	**2009**
		(In millions)		
Net Income (Loss)	**$ 83.8**	$ 28.3	**$ 275.1**	$ (91.4)
Other comprehensive income (OCI)				
Hedging instruments:				
Reclassification of net loss on hedging instruments from OCI to net income (loss), net of taxes	**179.4**	410.5	**287.9**	867.7
Net unrealized gain (loss) on hedging instruments, net of taxes	**70.9**	(57.3)	**(162.0)**	(396.5)
Available-for-sale securities:				
Reclassification of net (gain) loss on sales of securities from OCI to net (loss) income, net of taxes		(0.2)	**(0.1)**	29.5
Net unrealized gain on securities, net of taxes		45.6	**0.2**	18.9
Defined benefit obligations:				
Amortization of net actuarial loss, prior service cost, and transition obligation included in net periodic benefit cost, net of taxes	**4.9**	14.2	**10.8**	22.1
Net unrealized (loss) gain on foreign currency, net of taxes	**(10.7)**	2.5	**(9.0)**	4.5
Other comprehensive (loss) income equity investment in CENG, net of taxes	**(22.1)**		**(12.2)**	
Other comprehensive (loss) income other equity method investees, net of taxes	**(0.3)**	(2.4)	**(0.5)**	3.3
Comprehensive income	**305.9**	441.2	**390.2**	458.1
Less: Comprehensive income attributable to noncontrolling interests, net of taxes	**11.2**	20.2	**11.0**	24.0
Comprehensive Income Attributable to Common Stock	**$ 294.7**	$ 421.0	**$ 379.2**	$ 434.1

See Notes to Consolidated Financial Statements.
Certain prior-period amounts have been reclassified to conform with the current period's presentation.

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CONSOLIDATED BALANCE SHEETS

Constellation Energy Group, Inc. and Subsidiaries

	June 30, **2010***	*December 31,* **2009**
	(In millions)	
Assets		
Current Assets		
Cash and cash equivalents	**$ 1,603.2**	$ 3,440.0
Accounts receivable (net of allowance for uncollectibles of **$71.4** and $80.4, respectively)	**1,933.1**	1,778.2
Accounts receivable consolidated variable interest entities (net of allowance for uncollectibles of **$87.5** and $80.2, respectively)	**239.2**	359.4
Fuel stocks	**356.6**	314.9
Materials and supplies	**101.7**	93.3
Derivative assets	**558.2**	639.1
Unamortized energy contract assets (includes **$382.0** and $371.3, respectively, related to CENG)	**447.7**	436.5
Restricted cash	**2.0**	2.7
Restricted cash consolidated variable interest entities	**73.9**	24.3
Deferred income taxes	**88.0**	127.9
Other	**166.1**	244.4
Total current assets	**5,569.7**	7,460.7
Investments and Other Noncurrent Assets		
Investment in CENG	**5,164.8**	5,222.9
Other investments	**399.7**	424.3
Regulatory assets (net)	**386.7**	414.4
Goodwill	**25.5**	25.5
Derivative assets	**550.2**	633.9
Unamortized energy contract assets (includes **$210.4** and $400.9, respectively, related to CENG)	**372.1**	604.7
Other	**254.4**	304.2
Total investments and other noncurrent assets	**7,153.4**	7,629.9
Property, Plant and Equipment		
Property, plant and equipment	**13,193.7**	12,534.5
Accumulated depreciation	**(4,207.4)**	(4,080.7)
Net property, plant and equipment	**8,986.3**	8,453.8
Total Assets	**$ 21,709.4**	$ 23,544.4

** Unaudited*
See Notes to Consolidated Financial Statements.
Certain prior-period amounts have been reclassified to conform with the current period's presentation.

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CONSOLIDATED BALANCE SHEETS

Constellation Energy Group, Inc. and Subsidiaries

	June 30, **2010***	*December 31,* **2009**
	(In millions)	
Liabilities and Equity		
Current Liabilities		
Short-term borrowings	**$ 29.0**	$ 46.0
Current portion of long-term debt		0.4
Current portion of long-term debt consolidated variable interest entities	**58.1**	56.5
Accounts payable	**987.6**	916.3
Accounts payable consolidated variable interest entities	**152.7**	234.2
Derivative liabilities	**621.6**	632.6
Unamortized energy contract liabilities	**249.9**	390.1
Accrued taxes	**55.3**	877.3
Accrued expenses	**275.2**	409.8
Other	**388.8**	477.5
Total current liabilities	**2,818.2**	4,040.7
Deferred Credits and Other Noncurrent Liabilities		
Deferred income taxes	**3,185.1**	3,205.5
Asset retirement obligations	**30.4**	29.3
Derivative liabilities	**633.0**	674.1
Unamortized energy contract liabilities	**472.5**	653.7
Defined benefit obligations	**734.9**	743.9
Deferred investment tax credits	**29.8**	32.0
Other	**345.8**	388.8
Total deferred credits and other noncurrent liabilities	**5,431.5**	5,727.3
Long-term Debt, Net of Current Portion	**3,765.4**	4,359.6
Long-term Debt, Net of Current Portion consolidated variable interest entities	**424.7**	454.4
Equity		
Common shareholders' equity:		
Common stock	**3,284.8**	3,229.6
Retained earnings	**6,614.5**	6,461.0
Accumulated other comprehensive loss	**(878.4)**	(993.5)
Total common shareholders' equity	**9,020.9**	8,697.1
BGE preference stock not subject to mandatory redemption	**190.0**	190.0
Noncontrolling interests	**58.7**	75.3
Total equity	**9,269.6**	8,962.4
Commitments, Guarantees, and Contingencies (see Notes)		

Total Liabilities and Equity	**$ 21,709.4**	$ 23,544.4

** Unaudited*
See Notes to Consolidated Financial Statements.
Certain prior-period amounts have been reclassified to conform with the current period's presentation.

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CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

Constellation Energy Group, Inc. and Subsidiaries

Six Months Ended June 30,	**2010**	**2009**
	(In millions)	
Cash Flows From Operating Activities		
Net income (loss)	**$ 275.1**	$ (91.4)
Adjustments to reconcile to net cash (used in) provided by operating activities		
Depreciation, depletion, and amortization	**256.7**	297.5
Amortization of nuclear fuel		67.0
Amortization of energy contracts and derivatives designated as hedges	**70.6**	(86.7)
All other amortization	**14.6**	74.9
Accretion of asset retirement obligations	**0.9**	36.1
Deferred income taxes	**(47.9)**	(121.6)
Investment tax credit adjustments	**(2.2)**	(3.0)
Deferred fuel costs	**39.0**	32.4
Defined benefit obligation expense	**33.7**	64.7
Defined benefit obligation payments	**(39.0)**	(328.6)
Workforce reduction costs		11.2
Impairment losses and other costs		95.8
Impairment losses on nuclear decommissioning trust assets		62.4
Merger termination and strategic alternatives costs		37.2
(Gain) loss on divestitures	**(5.2)**	464.1
Equity in earnings of affiliates less than dividends received	**69.7**	18.5
Derivative contracts classified as financing activities	**79.8**	785.3
Changes in:		
Accounts receivable, excluding margin	**21.1**	599.2
Derivative assets and liabilities, excluding collateral	**227.3**	185.2
Net collateral and margin	**(73.4)**	1,094.9
Materials, supplies, and fuel stocks	**(44.2)**	323.4
Other current assets	**49.8**	237.0
Accounts payable	**(29.9)**	(786.1)
Accrued taxes and other current liabilities	**(1,063.9)**	(156.0)
Other	**(39.2)**	51.0
Net cash (used in) provided by operating activities	**(206.6)**	2,964.4
Cash Flows From Investing Activities		
Investments in property, plant and equipment	**(425.0)**	(809.1)
Asset and business acquisitions, net of cash acquired	**(372.9)**	
Investments in nuclear decommissioning trust fund securities		(233.4)
Proceeds from nuclear decommissioning trust fund securities		214.7
Proceeds from sales of investments and other assets	**21.2**	80.9
Proceeds from investment tax credits and grants related to renewable energy investments	**21.5**	
Contract and portfolio acquisitions	**(29.0)**	(2,153.7)
(Increase) decrease in restricted funds	**(30.0)**	1,004.4
Other	**(0.7)**	(1.8)
Net cash used in investing activities	**(814.9)**	(1,898.0)
Cash Flows From Financing Activities		
Net repayment of short-term borrowings	**(17.0)**	(515.8)
Proceeds from issuance of common stock	**8.8**	13.6
Proceeds from issuance of long-term debt		109.0
Repayment of long-term debt	**(629.0)**	(1,180.3)
Debt issuance costs	**(0.7)**	(62.8)
Common stock dividends paid	**(92.6)**	(133.7)

BGE preference stock dividends paid	**(6.6)**	(6.6)
Proceeds from contract and portfolio acquisitions	**2.3**	2,243.1
Derivative contracts classified as financing activities	**(79.8)**	(785.3)
Other	**(0.7)**	11.8
Net cash used in financing activities	**(815.3)**	(307.0)
Net (Decrease) Increase in Cash and Cash Equivalents	**(1,836.8)**	759.4
Cash and Cash Equivalents at Beginning of Period	**3,440.0**	202.2
Cash and Cash Equivalents at End of Period	**$ 1,603.2**	$ 961.6

See Notes to Consolidated Financial Statements.

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CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

Baltimore Gas and Electric Company and Subsidiaries

	Three Months Ended June 30,		*Six Months Ended June 30,*	
	2010	**2009**	**2010**	**2009**
		(In millions)		
Revenues				
Electric revenues	**$ 651.1**	$ 655.7	**$ 1,402.4**	$ 1,462.5
Gas revenues	**100.4**	111.7	**418.4**	498.6
Total revenues	**751.5**	767.4	**1,820.8**	1,961.1
Expenses				
Operating expenses				
Electricity purchased for resale	**286.8**	260.0	**636.4**	580.9
Electricity purchased for resale from affiliate	**114.6**	142.5	**238.6**	346.8
Gas purchased for resale	**42.1**	51.6	**236.6**	309.7
Operations and maintenance	**118.6**	121.3	**239.1**	226.4
Operations and maintenance from affiliate	**27.9**	27.6	**56.4**	49.5
Depreciation and amortization	**60.6**	65.7	**128.3**	132.6
Taxes other than income taxes	**45.0**	44.4	**92.6**	92.2
Total expenses	**695.6**	713.1	**1,628.0**	1,738.1
Income from Operations	**55.9**	54.3	**192.8**	223.0
Other Income	**5.5**	7.2	**12.0**	14.7
Fixed Charges				
Interest expense	**33.9**	36.0	**68.3**	72.7
Allowance for borrowed funds used during construction	**(1.5)**	(1.1)	**(2.8)**	(2.1)
Total fixed charges	**32.4**	34.9	**65.5**	70.6
Income Before Income Taxes	**29.0**	26.6	**139.3**	167.1
Income Taxes	**12.0**	10.6	**57.9**	66.1
Net Income	**17.0**	16.0	**81.4**	101.0
Preference Stock Dividends	**3.3**	3.3	**6.6**	6.6
Net Income Attributable to Common Stock	**$ 13.7**	$ 12.7	**$ 74.8**	$ 94.4

See Notes to Consolidated Financial Statements.
Certain prior-period amounts have been reclassified to conform with the current period's presentation.

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CONSOLIDATED BALANCE SHEETS

Baltimore Gas and Electric Company and Subsidiaries

	June 30, **2010***	*December 31,* **2009**
	(In millions)	
Assets		
Current Assets		
Cash and cash equivalents	**$ 260.2**	$ 13.6
Accounts receivable (net of allowance for uncollectibles of **$33.3** and $46.2, respectively)	**319.3**	311.7
Accounts receivable, unbilled (net of allowance for uncollectibles of **$1.0** and $1.0, respectively)	**227.3**	252.7
Investment in cash pool, affiliated company		314.7
Accounts receivable, affiliated companies	**2.5**	15.4
Fuel stocks	**51.1**	73.8
Materials and supplies	**31.7**	31.9
Prepaid taxes other than income taxes	**0.2**	49.5
Regulatory assets (net)	**55.2**	72.5
Restricted cash consolidated variable interest entity	**23.5**	24.3
Deferred income taxes		11.2
Other	**10.1**	11.3
Total current assets	**981.1**	1,182.6
Investments and Other Assets		
Regulatory assets (net)	**386.7**	414.4
Receivable, affiliated company	**322.5**	326.2
Other	**58.1**	98.2
Total investments and other assets	**767.3**	838.8
Utility Plant		
Plant in service		
Electric	**4,882.2**	4,772.4
Gas	**1,278.3**	1,260.6
Common	**499.2**	499.0
Total plant in service	**6,659.7**	6,532.0
Accumulated depreciation	**(2,382.4)**	(2,318.2)
Net plant in service	**4,277.3**	4,213.8
Construction work in progress	**249.0**	215.5
Plant held for future use	**6.6**	2.4

Net utility plant		**4,532.9**		4,431.7
Total Assets	**$**	**6,281.3**	$	6,453.1

** Unaudited*
See Notes to Consolidated Financial Statements.

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CONSOLIDATED BALANCE SHEETS

Baltimore Gas and Electric Company and Subsidiaries

	June 30, **2010***	*December 31,* **2009**
	(In millions)	
Liabilities and Equity		
Current Liabilities		
Short-term borrowings	**$**	$ 46.0
Current portion of long-term debt consolidated variable interest entity	**58.1**	56.5
Accounts payable	**157.6**	166.0
Accounts payable, affiliated companies	**73.8**	98.3
Customer deposits	**78.5**	76.0
Deferred income taxes	**29.4**	
Accrued taxes	**37.0**	80.2
Residential customer rate credit		112.4
Accrued expenses and other	**87.8**	96.1
Total current liabilities	**522.2**	731.5
Deferred Credits and Other Liabilities		
Deferred income taxes	**1,107.2**	1,087.6
Payable, affiliated company	**243.3**	243.4
Deferred investment tax credits	**9.0**	9.5
Liability for uncertain tax positions	**67.7**	73.3
Other	**16.5**	20.0
Total deferred credits and other liabilities	**1,443.7**	1,433.8
Long-term Debt		
Rate stabilization bonds consolidated variable interest entity	**482.8**	510.9
Other long-term debt	**1,431.5**	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	**(2.1)**	(2.2)
Current portion of long-term debt consolidated variable interest entity	**(58.1)**	(56.5)
Total long-term debt	**2,111.8**	2,141.4
Equity		
Common shareholder's equity	**2,013.6**	1,938.8
Preference stock not subject to mandatory redemption	**190.0**	190.0
Noncontrolling interest		17.6
Total equity	**2,203.6**	2,146.4
Commitments, Guarantees, and Contingencies (see Notes)		
Total Liabilities and Equity	**$ 6,281.3**	$ 6,453.1

** Unaudited*
See Notes to Consolidated Financial Statements.

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CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

Baltimore Gas and Electric Company and Subsidiaries

Six Months Ended June 30,	2010	2009
	(In millions)	
Cash Flows From Operating Activities		
Net income	**$ 81.4**	$ 101.0
Adjustments to reconcile to net cash provided by operating activities		
Depreciation and amortization	**128.3**	132.6
Other amortization	**1.6**	3.7
Deferred income taxes	**55.2**	46.7
Investment tax credit adjustments	**(0.5)**	(0.5)
Deferred fuel costs	**39.0**	32.4
Defined benefit plan expenses	**17.4**	17.5
Allowance for equity funds used during construction	**(5.2)**	(4.2)
Changes in:		
Accounts receivable	**16.0**	82.8
Accounts receivable, affiliated companies	**12.9**	2.2
Materials, supplies, and fuel stocks	**22.9**	87.8
Other current assets	**49.9**	57.9
Accounts payable	**(7.8)**	(111.6)
Accounts payable, affiliated companies	**(24.5)**	(38.3)
Other current liabilities	**(119.8)**	10.6
Long-term receivables and payables, affiliated companies	**(13.9)**	(171.8)
Other	**(71.7)**	(3.1)
Net cash provided by operating activities	**181.2**	245.7
Cash Flows From Investing Activities		
Utility construction expenditures (excluding equity portion of allowance for funds used during construction)	**(190.3)**	(166.7)
Change in cash pool at parent	**314.7**	(5.2)
Proceeds from sales of investments and other assets	**20.9**	
Decrease in restricted funds	**0.8**	0.7
Net cash provided by (used in) investing activities	**146.1**	(171.2)
Cash Flows From Financing Activities		
Repayment of long-term debt	**(28.1)**	(51.6)
Net repayment of short-term borrowings	**(46.0)**	(30.1)
Debt issuance costs		(0.3)
Contribution from noncontrolling interest		8.0
Preference stock dividends paid	**(6.6)**	(6.6)
Net cash used in financing activities	**(80.7)**	(80.6)
Net Increase (Decrease) in Cash and Cash Equivalents	**246.6**	(6.1)
Cash and Cash Equivalents at Beginning of Period	**13.6**	10.7
Cash and Cash Equivalents at End of Period	**$ 260.2**	$ 4.6

See Notes to Consolidated Financial Statements.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

Basis of Presentation

This Quarterly Report on Form 10-Q is a combined report of Constellation Energy Group, Inc. (Constellation Energy) and Baltimore Gas and Electric Company (BGE). References in this report to "we" and "our" are to Constellation Energy and its subsidiaries, collectively. References in this report to the "regulated business(es)" are to BGE.

Various factors can have a significant impact on our results for interim periods. This means that the results for this quarter are not necessarily indicative of future quarters or full year results given the seasonality of our business.

Our interim financial statements on the previous pages reflect all adjustments that management believes are necessary for the fair statement of the results of operations for the interim periods presented. These adjustments are of a normal recurring nature.

Reclassifications

In accordance with the presentation requirements for consolidated variable interest entities (VIEs), which we adopted on January 1, 2010, we have separately presented the following material assets and liabilities of these VIEs on our, and/or BGE's, Consolidated Balance Sheets:

"Accounts receivable consolidated variable interest entities,"

"Restricted cash consolidated variable interest entities,"

"Current portion of long-term debt consolidated variable interest entities,"

"Accounts payable consolidated variable interest entities," and

"Long-term Debt, Net of Current Portion consolidated variable interest entities."

We discuss our adoption of the reporting requirements for consolidated variable interest entities below in the *Variable Interest Entities* section.

We have also reclassified certain prior-period amounts:

We have separately presented "Other comprehensive income other equity method investees, net of taxes" that was previously reported within "Reclassification of net loss on hedging instruments from OCI to net income (loss), net of taxes" and "Net unrealized gain (loss) on hedging instruments, net of taxes" on our Consolidated Statements of Comprehensive Income (Loss).

We have separately presented "Electricity purchased for resale from affiliate" that was previously reported within "Electricity purchased for resale" on BGE's Consolidated Statements of Income.

We have separately presented "Operations and maintenance from affiliate" that was previously reported within "Operations and maintenance" on BGE's Consolidated Statements of Income.

We have separately presented "Accounts Payable" that was previously reported within "Accounts Payable and Accrued Liabilities" on our Consolidated Balance Sheets.

Variable Interest Entities

Effective January 1, 2010, we adopted new accounting, presentation, and disclosure requirements related to VIEs. 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 consolidate three VIEs for which we are the primary beneficiary, and we have significant interests in six VIEs for which we do not have controlling financial interests and, accordingly, are not the primary beneficiary.

Consolidated Variable Interest Entities

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 Maryland 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

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for rate stabilization charges to BondCo. During the quarter and six months ended June 30, 2010, BGE remitted $18.2 million and $42.0 million, respectively, to BondCo.

BGE did not provide any additional financial support to BondCo during the quarter and six months ended June 30, 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.

During 2009, our retail gas operation formed two new entities and combined them with our existing retail gas operation 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 letter of credit and 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 June 30, 2010, we provided a $100 million parental guarantee and a $37 million letter of credit to the third party gas supplier in support of the retail gas entity group.

Other than credit support provided by the parental guarantee and the letter of credit, 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 the quarter and six months ended June 30, 2010, other than the parental guarantee and the letter of credit.

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.

The carrying amounts and classification of the above three consolidated VIEs' assets and liabilities included in our consolidated financial statements at June 30, 2010 are as follows:

	(In millions)	
Current assets	$	475.8
Noncurrent assets		74.1
Total Assets	$	549.9
Current liabilities	$	299.5
Noncurrent liabilities		434.1
Total Liabilities	$	733.6

All of the assets in the table above are restricted for settlement of the VIE obligations and all of the liabilities in the table above can only be settled using VIE resources.

Unconsolidated Variable Interest Entities

As of June 30, 2010, we had significant interests in six VIEs for which we were not the primary beneficiary. Other than the obligations listed in the table below, we have not provided any material financial or other support to these entities during the quarter and six months ended June 30, 2010 and we do not intend to provide any additional financial or other support to these entities in the future.

The nature of these entities and our involvement with them are described in the following table:

VIE Category	Nature of Entity Financing	Nature of Constellation Energy Involvement	Obligations or Requirement to Provide Financial Support	Date of Involvement
Power contract monetization entities (2 entities)	Combination of debt and equity financing	Power sale agreements, loans, and guarantees	$30.5 million in letters of credit	March 2005
Power projects and fuel supply entities (4 entities)	Combination of debt and equity financing	Equity investments and guarantees	$5.0 million debt guarantee and working capital funding	Prior to 2003

For purposes of aggregating the various VIEs for disclosure, we evaluated the risk and reward characteristics for, and the significance of, each VIE. We discuss the nature of our involvement with the power contract monetization VIEs in detail in *Note 4* of our 2009 Annual Report on Form 10-K.

We concluded that power over the most economically significant activities of two of the power project VIEs is shared equally among the equity holders. Accordingly,

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neither of the equity holders consolidate these VIEs. The equity holders own 50% interests in these VIEs and all of the significant decisions require the mutual consent of the equity holders.

The following is summary information available as of June 30, 2010 about these entities:

	Power Contract Monetization VIEs	All Other VIEs	Total
	(In millions)		
Total assets	$ 498.5	$ 315.6	$ 814.1
Total liabilities	388.2	111.0	499.2
Our ownership interest		53.2	53.2
Other ownership interests	110.3	151.4	261.7
Our maximum exposure to loss	30.5	59.4	89.9
Carrying amount and location of variable interest on balance sheet:			
-Other investments		54.4	54.4

Our maximum exposure to loss is the loss that we would incur in the unlikely event that our interests in all of these entities were to become worthless and we were required to fund the full amount of all obligations associated with these entities. Our maximum exposure to loss as of June 30, 2010 consists of the following:

- the carrying amount of our investment totaling $54.4 million, and
- debt and payment guarantees totaling $35.5 million.

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 VIEs.

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 period. 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 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:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(In millions)			
Non-dilutive stock options	**4.4**	5.0	**4.4**	5.3
Dilutive common stock equivalent shares	**1.8**	0.8	**1.6**	0.5

As a result of the Company incurring a loss for the six months ended June 30, 2009, dilutive common stock equivalent shares were not included in calculating diluted EPS for that reporting period.

Acquisitions

Criterion Wind Project

In April 2010, we completed the acquisition of the Criterion wind project in Garrett County, Maryland. This 70 MW wind energy project will be developed, constructed, and owned by our Generation business and is expected to have a completed cost of approximately $140 million. We expect to place this facility in commercial operation during the first quarter of 2011.

Texas Combined Cycle Generation Facilities

In May 2010, we acquired the 550 MW Colorado Bend Energy Center and the 550 MW Quail Run Energy Center natural gas combined cycle generation facilities in Texas. 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 acquired 100% ownership of these facilities for $372.9 million, all of which was paid in cash at closing.

We recorded the major classes of assets acquired and liabilities assumed as follows:

At May 17, 2010		
Current assets	$	8.6
Property, plant and equipment		367.4
Total assets acquired		376.0
Current liabilities		(3.1)
Net assets acquired	$	372.9

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The preliminary net assets acquired are based on estimates and the purchase price is subject to adjustment, which could impact the amounts recognized for net assets acquired.

The pro-forma impact of this acquisition would not have been material to our results of operations for the quarter and six months ended June 30, 2010 and 2009.

Divestiture

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 million. In the third quarter of 2010, our Generation business will record an approximately $38 million pre-tax gain on this transaction. We will have no further involvement in the activities of this generating facility.

Investment in Constellation Energy Nuclear Group, LLC (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 Group and affiliates (EDF). As a result of this transaction, 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 and began to record our investment in CENG under the equity method of accounting. For the quarter and six months ended June 30, 2010, our equity investment losses were as follows:

	Quarter Ended June 30, 2010	Six Months Ended June 30, 2010
	(In millions)	
CENG	$ 40.2	$ 63.6
Amortization of basis difference in CENG	(61.5)	(104.2)
Total equity investment losses CENG[1]	$ (21.3)	$ (40.6)

1 For the quarter and six months ended June 30, 2010, total equity investment losses in CENG includes $0.5 million and $1.6 million, respectively, of expense related to the portion of cost of certain share-based awards that we fund on behalf of EDF.

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 of CENG were retained at their carrying value. See *Note 2* to our 2009 Annual Report on Form 10-K for a more detailed discussion.

Summarized income statement information for CENG for the quarter and six months ended June 30, 2010 is as follows:

	Quarter Ended June 30, 2010	Six Months Ended June 30, 2010
	(In millions)	
Revenues	**$ 376.1**	$ 737.0
Fuel and purchased energy expenses	**53.4**	111.8
Income from operations	**73.2**	110.8
Net income	**81.3**	130.4

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Information by Operating Segment

In connection with the strategic initiatives that were undertaken in 2008 and 2009, we re-aligned our reporting structure, beginning January 1, 2010, to reflect our current view of managing the business. As a result, as of January 1, 2010, we changed our reportable segments and have recast prior period information to conform with the current presentation.

Our reportable operating segments are Generation, NewEnergy (referred to as Customer Supply in our 2009 Annual Report on Form 10-K), 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 and Canada,
- an operation that manages certain contractually owned physical assets, including generating facilities,
- an interest in a nuclear generation joint venture (CENG) that owns, operates, and maintains five nuclear generating units, and
- an interest in a joint venture (UniStar Nuclear Energy, LLC (UNE)) to develop, own, and operate new nuclear projects in the United States.

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 electricity 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.

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	Reportable Segments				Holding Company and		
	Generation	NewEnergy	Regulated Electric	Regulated Gas	Other	Eliminations	Consolidated
	(In millions)						
Quarter ended June 30,							
2010							
Unaffiliated revenues	**$ 283.0**	**$ 2,276.1**	**$ 651.1**	**$ 99.6**	**$ 0.1**	**$**	**$ 3,309.9**
Intersegment revenues	**267.3**	**114.7**		**0.8**		**(382.8)**	
Total revenues	**550.3**	**2,390.8**	**651.1**	**100.4**	**0.1**	**(382.8)**	**3,309.9**
Net income (loss)	**15.3**	**50.8**	**20.9**	**(3.9)**	**0.7**		**83.8**
Net income (loss) attributable to common stock	**15.3**	**42.9**	**18.4**	**(4.7)**	**0.7**		**72.6**
2009							
Unaffiliated revenues	$ 168.3	$ 2,926.0	$ 655.7	$ 111.1	$ 3.0	$	$ 3,864.1
Intersegment revenues	514.2	52.1		0.6		(566.9)	
Total revenues	682.5	2,978.1	655.7	111.7	3.0	(566.9)	3,864.1
Net income (loss)	62.1	(46.1)	22.1	(6.2)	(3.6)		28.3
Net income (loss) attributable to common stock	62.1	(62.9)	19.5	(6.9)	(3.7)		8.1
Six months ended June 30,							
2010							
Unaffiliated revenues	**$ 574.2**	**$ 4,503.1**	**$ 1,402.4**	**$ 416.7**	**$ 0.1**	**$**	**$ 6,896.5**
Intersegment revenues	**556.0**	**238.6**		**1.7**		**(796.3)**	
Total revenues	**1,130.2**	**4,741.7**	**1,402.4**	**418.4**	**0.1**	**(796.3)**	**6,896.5**
Net income (loss)	**42.4**	**154.9**	**48.1**	**33.3**	**(3.6)**		**275.1**
Net income (loss) attributable to common stock	**42.4**	**150.5**	**43.0**	**31.8**	**(3.6)**		**264.1**
2009							
Unaffiliated revenues	$ 350.1	$ 5,854.0	$ 1,462.5	$ 495.4	$ 5.5	$	$ 8,167.5
Intersegment revenues	1,117.9	138.9		3.2		(1,260.0)	
Total revenues	1,468.0	5,992.9	1,462.5	498.6	5.5	(1,260.0)	8,167.5
Net income (loss)	103.6	(292.4)	67.5	33.4	(3.5)		(91.4)
Net income (loss) attributable to common stock	103.6	(309.7)	62.4	31.9	(3.6)		(115.4)

Certain prior-period amounts have been restated to conform with the current period's reportable segment presentation.

Our Generation business operating results for the quarter and six months ended June 30, 2010 include the following after-tax charges:

- *deferred income tax expense relating to federal subsidies for providing post-employment prescription drug benefits of zero and $0.8 million, respectively, as a result of healthcare reform legislation enacted in March 2010,*
- *amortization of basis difference in investment in CENG of $37.0 million and $62.7 million, respectively,*
- *impact of power purchase agreement with CENG of $29.1 million and $54.8 million, respectively, (amount represents the amortization of our "unamortized energy contract asset" less our 50.01% equity in CENG's amortization of its "unamortized energy contract liability"),*
- *loss on early retirement of 2012 Notes of zero and $30.9 million, respectively, and*
- *amortization of credit facility amendment fees in connection with the EDF transaction of $1.9 million and $3.8 million, respectively.*

Our NewEnergy business operating results for the quarter and six months ended June 30, 2010 include the following after-tax charges:

deferred income tax expense relating to federal subsidies for providing post-employment prescription drug benefits of zero and $0.1 million, respectively, as a result of healthcare reform legislation enacted in March 2010, and

amortization of credit facility amendment fees in connection with the EDF transaction of $1.0 million and $2.0 million, respectively.

Our Regulated Electric business operating results for the six months ended June 30, 2010 include an after-tax charge for the deferred income tax expense relating to federal subsidies for providing post-employment prescription drug benefits of $3.1 million as a result of healthcare reform legislation enacted in March 2010.

Our Holding Company and Other businesses operating results for the six months ended June 30, 2010 include an after-tax charge for the deferred income tax expense relating to federal subsidies for providing post-employment prescription drug benefits of $4.8 million as a result of healthcare reform legislation enacted in March 2010.

Total assets declined approximately $1.8 billion during 2010 due primarily to a decrease in cash and cash equivalents as a result of income taxes paid on the transaction with EDF and the retirement of debt.

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Pension and Postretirement Benefits

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

	Quarter Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(In millions)			
Components of net periodic pension benefit cost				
Service cost	**$ 9.1**	$ 14.4	**$ 18.6**	$ 29.6
Interest cost	**19.7**	31.1	**41.4**	58.3
Expected return on plan assets	**(23.2)**	(38.9)	**(49.9)**	(68.5)
Recognized net actuarial loss	**8.7**	11.1	**16.8**	21.7
Amortization of prior service cost	**0.9**	2.5	**1.9**	5.8
Amount capitalized as construction cost	**(2.9)**	(2.8)	**(4.8)**	(5.4)
Net periodic pension benefit cost[1]	**$ 12.3**	$ 17.4	**$ 24.0**	$ 41.5

1 BGE's portion of our net periodic pension benefit cost, excluding amounts capitalized, was $8.5 million for the quarter ended June 30, 2010 and $7.2 million for the quarter ended June 30, 2009. BGE's portion of our net periodic pension benefit cost, excluding amounts capitalized, was $14.8 million for the six months ended June 30, 2010 and $14.4 million for the six months ended June 30, 2009. Net periodic pension benefit costs exclude settlement charges of $1.5 million in the quarter and six months ended June 30, 2010 and $7.7 million in the quarter and six months ended June 30, 2009.

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

	Quarter Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(In millions)			
Components of net periodic postretirement benefit cost				
Service cost	**$ 0.6**	$ 2.0	**$ 1.3**	$ 3.6
Interest cost	**5.0**	6.3	**9.7**	12.1
Amortization of transition obligation	**0.6**	0.6	**1.1**	1.1
Recognized net actuarial (gain) loss	**(0.1)**	0.4	**0.2**	1.1
Amortization of prior service cost	**(0.7)**	(1.0)	**(1.4)**	(1.8)
Amount capitalized as construction cost	**(1.6)**	(1.8)	**(2.9)**	(3.3)
Net periodic postretirement benefit cost[1]	**$ 3.8**	$ 6.5	**$ 8.0**	$ 12.8

1 BGE's portion of our net periodic postretirement benefit cost, excluding amounts capitalized, was $4.6 million for the quarter ended June 30, 2010 and $5.2 million for the quarter ended June 30, 2009. BGE's portion of our net periodic postretirement benefit costs, excluding amounts capitalized, was $9.4 million for the six months ended June 30, 2010 and $9.8 million for the six months ended June 30, 2009.

Our non-qualified pension plans and our postretirement benefit programs are not funded; however, we have trust assets securing certain executive pension benefits. We estimate that we will incur approximately $9.8 million in pension benefit payments for our non-qualified pension plans and approximately $28.0 million for retiree health and life insurance costs in 2010. We contributed $12.2 million to our qualified pension plans in April 2010 and an additional $12.2 million in July 2010.

Healthcare Reform Legislation

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 the six months ended June 30, 2010.

Financing Activities

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.

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Constellation Energy had bank lines of credit under committed credit facilities totaling $4.0 billion at June 30, 2010 for short-term financial needs as follows:

Type of Credit Facility	Amount (In billions)	Expiration Date	Capacity Type
Syndicated Revolver	$ 2.32	July 2012	Letters of credit and cash
Commodity-linked	0.50	August 2014	Letter of credit
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	$ 4.02		

At June 30, 2010, we had approximately $1.3 billion in letters of credit issued including $0.3 billion in letters of credit issued under the commodity-linked credit facility discussed below and no commercial paper outstanding or direct borrowings under these facilities.

The commodity-linked credit facility allows for the issuance of letters of credit 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 as natural gas price levels decrease compared to a reference price that is adjusted periodically.

At June 30, 2010, Constellation Energy had approximately $29 million of short-term notes outstanding with a weighted average effective interest rate of 6.4%.

BGE

BGE has a $600.0 million revolving credit facility expiring in 2011. 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 June 30, 2010, BGE had no commercial paper or direct borrowings outstanding. There were immaterial letters of credit outstanding at June 30, 2010.

Debt

Constellation Energy

As part of our voluntary commitment to reduce our debt by $1 billion with funds received from the EDF transaction, we retired the following debt during the six months ended June 30, 2010, completing this commitment.

7.00% Notes due April 1, 2012

In February 2010, we retired an aggregate principal amount of $486.5 million of our 7.00% Notes due April 1, 2012 pursuant to a cash tender offer, at a premium of approximately 11%. We recorded a loss on this transaction of $50.1 million within "Interest expense" on our Consolidated Statements of Income (Loss).

Tax-Exempt Notes

In March 2010, we repurchased our outstanding $47 million and $65 million variable rate tax-exempt notes. Since these notes are variable rate instruments, there was no gain or loss recorded upon repurchase.

Net Available Liquidity

The following table provides a summary of our, and BGE's, net available liquidity at June 30, 2010.

At June 30, 2010	Constellation Energy	BGE
	(In billions)	
Credit facilities[1]	$ 3.5	$ 0.6
Less: Letters of credit issued[1]	(1.0)	
Less: Cash drawn on credit facilities		
Undrawn facilities	2.5	0.6
Less: Commercial paper outstanding		
Net available facilities	2.5	0.6
Add: Cash and cash equivalents	1.3	0.3
Cash and facility liquidity	3.8	0.9
Add: EDF put arrangement	1.4	
Net available liquidity	$ 5.2	$ 0.9

1 Excludes $0.5 billion commodity-linked credit facility due to its contingent nature and $0.3 billion in letters of credit issued against it.

Other Sources of Liquidity

We have an asset put arrangement with EDF that provides us with an option at any time through December 31, 2010 to sell certain non-nuclear generation assets, at pre-agreed prices, to EDF for aggregate proceeds of no more than $2 billion pre-tax, or approximately $1.4 billion after-tax. The amount of after-tax proceeds will be impacted by the assets actually sold and the related tax impacts at that time.

Exercise of the put arrangement is conditioned upon the receipt of regulatory approvals and third party consents, the absence of any material liens on such assets, and the absence of a material adverse effect, as defined in the Investment Agreement. During the quarter ended June 30, 2010, we received the final expected regulatory approval for one of the assets, which increased the net after-tax liquidity available through the put arrangement to approximately $1.4 billion.

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Credit Facility Compliance and Covenants

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 June 30, 2010, the debt to capitalization ratio as defined in the credit agreements was 29%.

Under our $2.32 billion credit facility, we granted a lien on certain of our generating facilities and pledged our ownership interests in our nuclear business to the lenders upon the completion of the transaction with EDF.

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 June 30, 2010, the debt to capitalization ratio for BGE as defined in this credit agreement was 43%.

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 or exercise the put option with EDF 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.

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.

Income Taxes

We compute the income tax expense (benefit) for each quarter based on the estimated annual effective tax rate for the year. The effective tax rate was 30.9% and 32.6% for the quarter and six months ended June 30, 2010, respectively, compared to 78.3% and 60.4% for the same periods of 2009. The lower effective tax rate for the quarter ended June 30, 2010 reflects the impact of favorable adjustments (primarily related to reductions of uncertain tax positions and higher deductions for qualified production activities). The lower effective tax rate for the six months ended June 30, 2010 reflects the absence in 2010 of the impact of unfavorable nondeductible adjustments in 2009 (primarily related to nondeductible dividends on Series B preferred stock and the write-off of unamortized debt discount on senior notes) in relation to the lower estimated 2009 taxable income (primarily attributable to losses on the divestiture of a majority of our international commodities and our Houston-based gas trading operations).

The BGE effective tax rate was 41.4% and 41.6% for the quarter and six months ended June 30, 2010, respectively, compared to 39.8% and 39.6% for the same periods of 2009. The higher effective tax rate for 2010 is primarily due to the impact of the healthcare reform legislation enacted in the first quarter of 2010, which eliminates the tax exempt status of prescription drug subsidies received under Medicare Part D.

Unrecognized Tax Benefits

The following table summarizes the change in unrecognized tax benefits during 2010 and our total unrecognized tax benefits at June 30, 2010:

At June 30, 2010

	(In millions)
Total unrecognized tax benefits, January 1, 2010	$ 312.5
Increases in tax positions related to the current year	6.7
Increases in tax positions related to prior years	11.1
Reductions in tax positions related to prior years	(42.3)
Reductions in tax positions as a result of a lapse of the applicable statute of limitations	(0.6)
Total unrecognized tax benefits, June 30, 2010[1]	$ 287.4

1 BGE's portion of our total unrecognized tax benefits at June 30, 2010 was $100.1 million.

Increases in tax positions related to the current year and prior years are primarily due to unrecognized tax benefits for repair and depreciation deductions measured at amounts consistent with prior IRS examination results and state income tax accruals.

Reductions in tax positions related to prior years are primarily due to the resolution of the tax treatment of distributions received from our shipping joint venture, merger termination fees, the timing of losses from international coal hedges, and offsetting tax depreciation associated with potential disallowance of repair deductions.

Total unrecognized tax benefits as of June 30, 2010 of $287.4 million include outstanding claims of approximately

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$62.5 million, including $51.6 million in state tax credits, for which no tax benefit was recorded on our Consolidated Balance Sheet because refunds were not received and the claims do not meet the "more-likely-than-not" threshold.

If the total amount of unrecognized tax benefits of $287.4 million were ultimately realized, our income tax expense would decrease by approximately $170 million. However, the $170 million includes state tax refund claims of $51.6 million that have been disallowed by tax authorities and are subject to appeals.

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:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(In millions)			
Interest and penalties recorded as tax expense (benefit)	**$ (10.7)**	$ 1.5	**$ (7.3)**	$ 0.7

BGE's portion of interest and penalties was immaterial for both periods presented.

Accrued interest and penalties recognized in our Consolidated Balance Sheets were $15.8 million, of which BGE's portion was $2.3 million, at June 30, 2010, and $23.1 million, of which BGE's portion was $1.6 million, at December 31, 2009.

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, and BGE's, Consolidated Statements of Income (Loss). The taxes, surcharges, or fees that are included in revenues were as follows:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(In millions)			
Constellation Energy (including BGE)	**$ 30.5**	$ 23.8	**$ 61.5**	$ 54.5
BGE	**19.3**	18.5	**41.2**	40.1

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 June 30, 2010	**Stated Limit**
	(In billions)
Constellation Energy guarantees	$ 9.4
BGE guarantees	0.3

Total guarantees	$	9.7

At June 30, 2010, Constellation Energy had a total of $9.7 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 $9.4 billion as follows:

$8.6 billion on behalf of our Generation and NewEnergy businesses to allow them 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 $2 billion at June 30, 2010, which represents the total amount the parent company could be required to fund based on June 30, 2010 market prices. For those guarantees related to our derivative liabilities, the fair value of the obligation is recorded in our Consolidated Balance Sheets.

$0.6 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 $12.3 million for these guarantees on our Consolidated Balance Sheets.

$0.2 billion to its other nonregulated businesses.

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BGE guaranteed the Trust Preferred Securities of $250.0 million of BGE Capital Trust II.

Commitments and Contingencies

We have made substantial commitments in connection with our Generation, NewEnergy, 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
- long-term service agreements, capital for construction programs, and other.

Our Generation and NewEnergy businesses enter into various long-term 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 2010 and 2018. In addition, our NewEnergy business enters into long-term contracts for the capacity and transmission rights for the delivery of energy to meet our physical obligations to our customers. These contracts expire in various years between 2010 and 2030.

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

Our regulated electric business enters into various long-term contracts for the procurement of electricity. These contracts expire between 2010 and 2012 and represent BGE's estimated requirements to serve residential and small commercial customers as follows:

Contract Duration	*Percentage of Estimated Requirements*
From July 1, 2010 to May 2011	100%
From June 2011 to September 2011	75
From October 2011 to May 2012	50
From June 2012 to September 2012	25

The cost of power under these contracts is recoverable under the Provider of Last Resort agreement reached with the Maryland Public Service Commission (PSC).

Our regulated gas business enters into various long-term contracts for the procurement, transportation, and storage of gas. Our regulated gas business has gas procurement contracts that expire between 2010 and 2011, and transportation and storage contracts that expire between 2010 and 2027. The cost of gas under these contracts is recoverable under BGE's gas cost adjustment clause discussed in *Note 1* of our 2009 Annual Report on Form 10-K.

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

At June 30, 2010, the total amount of commitments was $6.3 billion. These commitments are primarily related to our Generation and NewEnergy businesses.

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 power plants. Our load-serving power sales contracts extend for terms through 2019 and provide for the sale of

energy to electricity distribution utilities and certain retail customers. Our power sales contracts associated with power plants we own extend for terms into 2016 and provide for the sale of all or a portion of the actual output of certain of our power plants. Substantially all long-term contracts were executed at pricing that approximated market rates, including profit margin, at the time of execution.

Contingencies

Litigation

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

Merger with MidAmerican

Beginning September 18, 2008, seven shareholders of Constellation Energy filed lawsuits in the Circuit Court for Baltimore City, Maryland challenging the then-pending merger with MidAmerican. Four similar suits were filed by other shareholders of Constellation Energy in the United States District Court for the District of Maryland.

The lawsuits claim that the merger consideration was inadequate and did not maximize value for shareholders, that the sales process leading up to the merger was flawed, and that unreasonable deal protection devices were agreed to in order to ward off competing bids. The federal lawsuits also assert that the conversion of preferred stock issued to MidAmerican into debt is not permitted under Maryland law.

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The termination of the MidAmerican merger renders moot the claims attempting to enjoin the merger with MidAmerican. One of the federal merger cases was voluntarily dismissed on December 31, 2008, and the other federal merger cases were dismissed as moot on May 27, 2009. Plaintiffs' counsel in six of the seven state merger cases have filed dismissals without prejudice of their MidAmerican merger claims. On April 16, 2010, the seventh merger case was dismissed without prejudice by the Court, thereby concluding these cases.

Securities Class Action

Three federal securities class action lawsuits have been 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 there 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. We are unable at this time to determine the ultimate outcome of the securities class actions or their possible effect on our, or BGE's financial results.

ERISA Actions

In the fall of 2008, multiple class action lawsuits were filed in the United States District Courts for the District of Maryland and the Southern District of New York against Constellation Energy; Mayo A. Shattuck III, Constellation Energy's Chairman of the Board, President and Chief Executive Officer; and others in their roles as fiduciaries of the Constellation Energy Employee Savings Plan. The actions, which have been consolidated into one action in Maryland (the Consolidated Action), allege that the defendants, in violation of various sections of ERISA, breached their fiduciary duties to prudently and loyally manage Constellation Energy Savings Plan's assets by designating Constellation Energy common stock as an investment, by failing to properly provide accurate information about the investment, by failing to avoid conflicts of interest, by failing to properly monitor the investment and by failing to properly monitor other fiduciaries. The plaintiffs seek to compel the defendants to reimburse the plaintiffs and the Constellation Energy Savings Plan for all losses resulting from the defendants' breaches of fiduciary duty, to impose a constructive trust on any unjust enrichment, to award actual damages with pre- and post-judgment interest, to award appropriate equitable relief including injunction and restitution and to award costs and expenses, including attorneys' fees. On October 2, 2009, the defendants moved to dismiss the consolidated complaint in its entirety. We are unable at this time to determine the ultimate outcome of the Consolidated Action or its possible effects on our, or BGE's, financial results.

Mercury

Since September 2002, BGE, Constellation Energy, and several other defendants have been involved in numerous actions filed in the Circuit Court for Baltimore City, Maryland alleging mercury poisoning from several sources, including coal plants formerly owned by BGE. The plants are now owned by a subsidiary of Constellation Energy. In addition to BGE and Constellation Energy, approximately 11 other defendants, consisting of pharmaceutical companies, manufacturers of vaccines, and manufacturers of Thimerosal have been sued. Approximately 70 cases, involving claims related to approximately 132 children, have been filed to date, with each claimant seeking $20 million in compensatory damages, plus punitive damages, from us.

The claims against BGE and Constellation Energy have been dismissed in all of the cases either with prejudice based on rulings by the Court or without prejudice based on voluntary dismissals by the plaintiffs' counsel. Plaintiffs may attempt to pursue appeals of the rulings in favor of BGE and Constellation Energy once the cases are finally concluded as to all defendants. We believe that we have

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meritorious defenses and intend to defend the actions vigorously. However, we cannot predict the timing, or outcome, of these cases, 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 488 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 and a small minority have been resolved for amounts that were not material to our financial results.

BGE and Constellation Energy do not know the specific facts necessary to estimate their potential liability for 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.

Until the relevant facts are determined, we are unable to estimate what our, or BGE's, liability might be. Although insurance and hold harmless agreements from contractors who employed the plaintiffs may cover a portion of any awards in the actions, the potential effect on our, or BGE's, financial results could be material.

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 liable 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 clean-up costs will not be known until the investigation is closer to completion, which is expected by late 2010. The completed investigation will provide a range of remediation alternatives to the EPA, and the EPA is expected to select one of the alternatives by the end of the third quarter of 2011. In addition, the allocation of the costs among the potentially responsible parties is not yet known. The clean-up costs we incur could have a material effect on our financial results.

Air Quality

In May 2007, a subsidiary of Constellation Energy entered into a consent decree with the Maryland Department of the Environment to resolve alleged violations of air quality opacity standards at three fossil fuel plants in Maryland. The consent decree requires the subsidiary to pay a $100,000 penalty, provide $100,000 to a supplemental environmental project, and install technology to control emissions from those plants. Our obligations under this consent decree were completed in May 2010.

In January 2009, the EPA issued a notice of violation (NOV) to a subsidiary of Constellation Energy, as well as the other owners and the operator of the Keystone coal-fired power plant in Shelocta, Pennsylvania. We hold an approximately 21% 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 are investigating the allegations and have entered into discussions with the EPA. We believe there are meritorious defenses to the allegations contained in the NOV. However, we cannot predict the outcome of this proceeding and it is not possible to determine our actual liability, if any, at this time.

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

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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. We recorded a liability in our Consolidated Balance Sheets of approximately $10.6 million, 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 $5.9 million of these costs as of June 30, 2010, resulting in a remaining liability at June 30, 2010 of $4.7 million. We estimate that it is reasonably possible that we could incur additional costs of up to approximately $10 million more than the liability that we accrued.

Insurance

We discuss our non-nuclear insurance programs in *Note 12* of our 2009 Annual Report on Form 10-K.

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 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.

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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 are derivatives, for which there are several possible accounting treatments. 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. The permissible accounting treatments include:

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

We discuss our accounting policies for derivatives and hedging activities and their impacts on our financial statements in *Note 1* of our 2009 Annual Report on Form 10-K.

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 and forecasted purchases of fuel and energy for the years 2010 through 2016. We had net unrealized pre-tax losses on these cash-flow hedges recorded in "Accumulated other comprehensive loss" of $744.6 million at June 30, 2010 and $951.3 million at December 31, 2009.

We expect to reclassify $576.7 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 June 30, 2010. However, the actual amount reclassified into earnings could vary from the amounts recorded at June 30, 2010, due to future changes in market prices.

When we determine that a forecasted transaction originally hedged has become probable of not occurring, we 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:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(In millions)			

Pre-tax gains (losses)	**$**	**1.1**	$	(74.6)	**$**	**(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 Comprehensive Income. 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 $7.3 million at June 30, 2010 and $11.3 million at December 31, 2009. We expect to reclassify $0.6 million of pre-tax net gains 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.

Fair Value Hedging

We elect fair value hedge accounting for a limited portion of our derivative contracts including certain interest rate swaps. The objectives for electing fair value hedging in these situations are to manage our exposure and to optimize the mix of our fixed and floating-rate debt.

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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.

We have interest rate swaps qualifying as fair value hedges relating to $400 million of our fixed-rate debt maturing in 2012 and 2015, and converted this notional amount of debt to floating-rate. The fair value of these hedges was an unrealized gain of $44.0 million at June 30, 2010 and $35.8 million at December 31, 2009 and was recorded 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.

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:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(In millions)			
Cash-flow hedges	**$ (37.6)**	$ 23.5	**$ (24.3)**	$ 52.6
Fair value hedges				23.9
Total	**$ (37.6)**	$ 23.5	**$ (24.3)**	$ 76.5

We did not have any fair value hedges for which we have excluded a portion of the change in fair value from our effectiveness assessment.

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 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.

Quantitative Information About Derivatives and Hedging Activities

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 types of market 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 tables, 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 tables we provide a reconciliation of the gross fair value components to the net fair value amounts as presented in the *Fair Value Measurements* note and our Consolidated Balance Sheets.

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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 gas operations, economic hedges of accrual activities, the total return swaps entered into to effect the sale of the international commodities and Houston- based gas trading operations, 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 June 30, 2010	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	$ 1,627.5	$ (2,013.0)	$ 11,159.2	$ (11,800.9)	$ 12,786.7	$ (13,813.9)
Gas contracts	2,095.6	(1,853.1)	4,360.1	(4,110.8)	6,455.7	(5,963.9)
Coal contracts	35.8	(33.5)	348.6	(343.9)	384.4	(377.4)
Other commodity contracts[1]			125.0	(79.7)	125.0	(79.7)
Interest rate contracts	44.0		37.4	(44.8)	81.4	(44.8)
Foreign exchange contracts			6.5	(4.5)	6.5	(4.5)
Total gross fair values	$ 3,802.9	$ (3,899.6)	$ 16,036.8	$ (16,384.6)	$ 19,839.7	$ (20,284.2)
Netting arrangements[5]					(18,850.0)	18,850.0
Cash collateral					(78.6)	179.6
Net fair values					$ 911.1	$ (1,254.6)
Net fair value by balance sheet line item:						
Accounts receivable[2]					$ (197.3)	
Derivative assets current					558.2	
Derivative assets noncurrent					550.2	
Derivative liabilities current						(621.6)
Derivative liabilities noncurrent						(633.0)
Total Derivatives					$ 911.1	$ (1,254.6)

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.

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As of December 31, 2009	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	$ 1,737.3	$ (2,292.1)	$ 11,729.3	$ (12,414.3)	$ 13,466.6	$ (14,706.4)
Gas contracts	1,860.6	(1,380.0)	4,159.1	(3,857.1)	6,019.7	(5,237.1)
Coal contracts	20.1	(40.8)	609.5	(627.2)	629.6	(668.0)
Other commodity contracts[1]	1.4	(0.8)	83.1	(32.1)	84.5	(32.9)
Interest rate contracts	35.8		28.5	(39.9)	64.3	(39.9)
Foreign exchange contracts			13.2	(9.0)	13.2	(9.0)
Total gross fair values	$ 3,655.2	$ (3,713.7)	$ 16,622.7	$ (16,979.6)	$ 20,277.9	$ (20,693.3)
Netting arrangements[5]					(19,261.0)	19,261.0
Cash collateral					(92.6)	125.6
Net fair values					$ 924.3	$ (1,306.7)
Net fair value by balance sheet line item:						
Accounts receivable[2]					$ (348.7)	
Derivative assets current					639.1	
Derivative assets noncurrent					633.9	
Derivative liabilities current						(632.6)
Derivative liabilities noncurrent						(674.1)
Total Derivatives					$ 924.3	$ (1,306.7)

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 tables 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 by contract type and accounting treatment. In order to achieve this objective, we prepare these tables 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 tables 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.

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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* of our 2009 Annual Report on Form 10-K.

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						*Quarter Ended June 30,*	
	Gain (Loss) Recorded in AOCI			**Gain (Loss) Reclassified from AOCI into Earnings**		**Ineffectiveness Gain (Loss) Recorded in Earnings**	
Contract type:	**2010**	**2009**	**Statement of Income (Loss) Line Item**	**2010**	**2009**	**2010**	**2009**
			(In millions)				
Hedges of forecasted sales:			Nonregulated revenues				
Power contracts	$ (80.8)	$ 100.4		$ (1.0)	$ (37.5)	$ (20.5)	$ 21.2
Gas contracts	1.8	7.9		16.2	(0.6)	(2.9)	4.5
Coal contracts							
Other commodity contracts[1]		(7.1)			(0.8)		(2.2)
Interest rate contracts					(0.2)		
Foreign exchange contracts							
Total gains (losses)	$ (79.0)	$ 101.2	Total included in nonregulated revenues	$ 15.2	$ (39.1)	$ (23.4)	$ 23.5
Hedges of forecasted purchases:			Fuel and purchased energy expense				
Power contracts	$ 163.9	$ (112.8)		$ (331.6)	$ (611.9)	$ (3.4)	$ (0.3)
Gas contracts	(2.6)	(21.2)		45.1	66.7	(13.1)	1.9
Coal contracts	32.6	(40.5)		(15.3)	(52.0)	2.3	(1.6)
		(3.7)			(2.7)		

Other commodity contracts[2]								
Foreign exchange contracts								
Total losses	$ 193.9	$ (178.2)	Total included in fuel and purchased energy expense	$ (301.8)	$ (599.9)	$ (14.2)	$	
Hedges of interest rates:			Interest expense					
Interest rate contracts				0.2	(0.1)			
Total gains	$	$	Total included in interest expense	$ 0.2	$ (0.1)	$	$	
Grand total (losses) gains	$ 114.9	$ (77.0)		$ (286.4)	$ (639.1)	$ (37.6)	$ 23.5	

1 Other commodity sale contracts include oil and freight contracts.
2 Other commodity purchase contracts include freight and emission allowances.

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Cash Flow Hedges				*Six Months Ended June 30,*			
	Gain (Loss) Recorded in AOCI			**Gain (Loss) Reclassified from AOCI into Earnings**		**Ineffectiveness Gain (Loss) Recorded in Earnings**	
Contract type:	**2010**	**2009**	**Statement of Income (Loss) Line Item**	**2010**	**2009**	**2010**	**2009**
			(In millions)				
Hedges of forecasted sales:			Nonregulated revenues				
Power contracts	$ 121.7	$ 262.2		$ (60.2)	$ (129.6)	$ 1.3	$ 81.0
Gas contracts	(33.1)	(23.9)		36.4	(22.0)	(4.0)	6.5
Coal contracts		10.0			(229.9)		
Other commodity contracts[1]		6.6		(0.7)	(3.6)		(5.1)
Interest rate contracts		(0.3)			(0.2)		
Foreign exchange contracts		0.3			(0.9)		
Total gains (losses)	$ 88.6	$ 254.9	Total included in nonregulated revenues	$ (24.5)	$ (386.2)	$ (2.7)	$ 82.4
Hedges of forecasted purchases:			Fuel and purchased energy expense				
Power contracts	$ (291.6)	$ (886.8)		$ (534.7)	$ (1,038.4)	$ (12.7)	$ (29.5)
Gas contracts	(76.2)	154.5		123.1	92.7	(13.1)	2.6
Coal contracts	21.8	(125.1)		(27.8)	(65.3)	4.0	(2.9)
Other commodity contracts[2]	(0.2)	(2.1)		(0.3)	23.1	0.2	
Foreign exchange contracts		0.1			0.1		
Total losses	$ (346.2)	$ (859.4)	Total included in fuel and purchased energy expense	$ (439.7)	$ (987.8)	$ (21.6)	$ (29.8)
Hedges of interest rates:			Interest expense				
Interest rate contracts				4.1	(0.2)		
Total gains	$	$	Total included in interest expense	$ 4.1	$ (0.2)	$	$
Grand total (losses) gains	$ (257.6)	$ (604.5)		$ (460.1)	$ (1,374.2)	$ (24.3)	$ 52.6

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 the gains and losses on derivatives designated as fair value hedges and the gains and losses on the hedged item represents the recognition of locked-in gains on terminated interest rate swaps.

Fair Value Hedges	*Quarter Ended June 30,*		*Six Months Ended June 30,*	
	Amount of Gain (Loss) Recognized in	**Amount of Gain (Loss) Recognized in**	**Amount of Gain (Loss) Recognized in**	**Amount of Gain (Loss) Recognized in**

Contract type:	Statement of Income (Loss) Line Item	Income on Derivative 2010	Income on Derivative 2009	Income on Hedged Item 2010	Income on Hedged Item 2009	Income on Derivative 2010	Income on Derivative 2009	Income on Hedged Item 2010	Income on Hedged Item 2009
					(In millions)				
Commodity contracts:									
Gas contracts	Nonregulated revenues	$	$	$	$	$	$ 40.6	$	$ (16.7)
Interest rate contracts	Interest expense	4.2	(20.4)	(4.1)	20.4	17.4	(15.5)	(15.2)	15.5
Total gains (losses)		$ 4.2	$ (20.4)	$ (4.1)	$ 20.4	$ 17.4	$ 25.1	$ (15.2)	$ (1.2)

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The following table presents gains and losses on mark-to-market derivatives. As discussed more fully in *Note 1* to our 2009 Annual Report on Form 10-K, 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		***Quarter Ended June 30,***		***Six Months Ended June 30,***	
		Amount of Gain (Loss) Recorded in Income on Derivative		**Amount of Gain (Loss) Recorded in Income on Derivative**	
Contract type:	**Statement of Income (Loss) Line Item**	**2010**	**2009**	**2010**	**2009**
			(In millions)		
Commodity contracts:					
Power contracts	Nonregulated revenues	$ 40.1	$ 58.4	$ (24.8)	$ 147.0
Gas contracts	Nonregulated revenues	5.0	(116.9)	30.7	(279.5)
Coal contracts	Nonregulated revenues	7.6	52.1	7.7	9.8
Other commodity contracts[1]	Nonregulated revenues	(3.8)	4.3	1.1	0.4
Coal contracts	Fuel and purchased energy expense		(2.2)		(107.7)
Interest rate contracts	Nonregulated revenues	(0.6)	(20.1)	(1.7)	(20.6)
Foreign exchange contracts	Nonregulated revenues	(1.2)	1.9	(2.1)	9.7
Total gains (losses)		$ 47.1	$ (22.5)	$ 10.9	$ (240.9)

1 Other commodity contracts for the quarter ended June 30, 2009 include oil, freight, weather, and emission allowances. For the quarter ended June 30, 2010 and for the six months ended June 30, 2010 and 2009, other commodity contracts also include uranium.

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. We conduct our business activities throughout the United States and internationally. 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. 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. Additionally, 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 are also

using 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. Accordingly, the use of derivative instruments is integral to the conduct of our business, and derivative instruments are an important tool

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through which we are able to manage and mitigate the risks that are inherent in our activities.

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

First, 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, these tables do 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 reduce those risks. They 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.

Additionally, the disclosure of derivative quantities potentially could reveal commercially valuable or otherwise competitively sensitive information that could limit the effectiveness and profitability of our business activities. Therefore, in the tables below, 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.

Finally, the volume information for commodity derivatives represents "delta equivalent" quantities, not gross notional amounts. We make use of different types of commodity derivative instruments such as forwards, futures, options, and swaps, and we believe that the delta equivalent quantity is the most relevant measure of the volume associated with these 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. Therefore, the volume information for commodity derivatives represents the delta equivalent quantity of those contracts, computed on the basis described above. For interest rate contracts and foreign currency contracts we have presented the notional amounts of such contracts in the tables below.

The following tables present the volume of our derivative activities as of June 30, 2010 and December 31, 2009 shown by contractual settlement year.

Quantities[1] Under Derivative Contracts — ***As of June 30, 2010***

Contract Type (Unit)	2010	2011	2012	2013	2014	Thereafter	Total
				(In millions)			
Power (MWh)	24.9	19.7	8.2	2.4	4.0	1.7	60.9
Gas (MMBTU)	39.3	50.3	13.4	39.8	45.3	19.3	207.4
Coal (Tons)	2.3	4.7	1.3	0.1			8.4
Oil (BBL)	0.3		0.1				0.4
Emission Allowances (Tons)	11.2						11.2
Interest Rate Contracts	$ 264.2	$ 204.4	$ 318.7	$ 241.8	$ 60.0	$ 250.0	$ 1,339.1
Foreign Exchange Rate Contracts	$ 31.5	$ 64.5	$ 7.7	$ 16.7	$ 16.8	$ 15.5	$ 152.7

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Quantities[1] Under Derivative Contracts *As of December 31, 2009*

Contract Type (Unit)	2010	2011	2012	2013	2014	Thereafter	Total
				(In millions)			
Power (MWh)	32.7	1.6	3.2	3.2	0.1	0.9	41.7
Gas (MMBTU)	37.3	37.4	22.1	21.0	22.7	21.3	161.8
Coal (Tons)	3.9	3.9	0.2				8.0
Oil (BBL)	0.3						0.3
Emission Allowances (Tons)	7.2						7.2
Interest Rate Contracts	$ 972.3	$ 140.6	$ 440.5	$ 58.2	$ 255.0	$ 200.0	$ 2,066.6
Foreign Exchange Rate Contracts	$ 27.9	$ 72.4	$ 16.7	$ 16.7	$ 16.8	$ 15.5	$ 166.0

1 Amounts in the tables 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 June 30, 2010 and December 31, 2009. Based on contractual provisions, we estimate that if Constellation Energy's senior unsecured debt were downgraded, our total contingent collateral obligation for derivatives in a net liability position was $0.2 billion at both June 30, 2010 and December 31, 2009, which represents 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. These amounts are associated with net derivative liabilities totaling $1.0 billion at both June 30, 2010 and December 31, 2009 after reflecting legally binding master netting agreements and collateral already posted.

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 tables 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 tables. 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.

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Credit-Risk Related Contingent Feature				As of June 30, 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)		
$ 7.7	$ (6.7)	$ 1.0	$ 0.8	$ 0.2

Credit-Risk Related Contingent Feature				As of December 31, 2009
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)		
$ 8.6	$ (7.6)	$ 1.0	$ 0.7	$ 0.2

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 $179.6 million and letters of credit of $601.0 million at June 30, 2010 and $125.6 million and letters of credit of $585.2 million at December 31, 2009.
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* to our 2009 Annual Report on Form 10-K. As of June 30, 2010, we had two counterparties that exceeded 10% of our total credit exposure, including derivative-related positions. We had an approximately 17% exposure related to the power purchase agreement executed in 2009 with CENG, and we had an approximately 11% exposure related to an electric cooperative customer.

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Fair Value Measurements

Recurring Measurements

Our assets and liabilities measured at fair value on a recurring basis consist of the following (BGE's assets and liabilities measured at fair value on a recurring basis are immaterial):

	As of June 30, 2010	
	Assets	**Liabilities**
	(In millions)	
Cash equivalents	$ 1,076.7	$
Equity securities	38.5	
Derivative instruments:		
Classified as derivative assets and liabilities:		
Current	558.2	(621.6)
Noncurrent	550.2	(633.0)
Total classified as derivative assets and liabilities	1,108.4	(1,254.6)
Classified as accounts receivable*	(197.3)	
Total derivative instruments	911.1	(1,254.6)
Total recurring fair value measurements	$ 2,026.3	$ (1,254.6)

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

Cash equivalents represent exchange-traded money market funds which are included in "Cash and cash equivalents" 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 derivative positions, including futures, forwards, swaps, and options. We classify exchange-listed contracts as part of "Accounts Receivable" in our Consolidated Balance Sheets. We classify the remainder of our derivative contracts as "Derivative assets" or "Derivative liabilities" in our Consolidated Balance Sheets.

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 the *Financing Activities* section.

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The table below sets 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 June 30, 2010. Our net derivative assets and liabilities are disaggregated on a gross contract-by-contract basis. 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. Therefore, the objective of this table 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.

At June 30, 2010	Level 1	Level 2	Level 3	Netting and Cash Collateral*	Total Net Fair Value
			(In millions)		
Cash equivalents	$ 1,076.7	$	$	$	$ 1,076.7
Equity securities	38.5				38.5
Derivative assets:					
Power contracts		11,882.0	904.7		
Gas contracts	52.6	6,267.2	135.9		
Coal contracts		342.9	41.5		
Other commodity contracts	7.7	25.0	92.3		
Interest rate contracts		81.4			
Foreign exchange contracts		6.5			
Total derivative assets	60.3	18,605.0	1,174.4	(18,928.6)	911.1
Derivative liabilities:					
Power contracts		(12,583.7)	(1,230.2)		
Gas contracts	(60.6)	(5,882.1)	(21.2)		
Coal contracts		(333.6)	(43.8)		
Other commodity contracts	(7.6)	(17.2)	(54.9)		
Interest rate contracts		(44.8)			
Foreign exchange contracts		(4.5)			
Total derivative liabilities	(68.2)	(18,865.9)	(1,350.1)	19,029.6	(1,254.6)
Net derivative position	(7.9)	(260.9)	(175.7)	101.0	(343.5)
Total	$ 1,107.3	$ (260.9)	$ (175.7)	$ 101.0	$ 771.7

** 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 June 30, 2010, we included $78.6 million of cash collateral held and $179.6 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.

We prepared this table by separating each individual derivative contract that is in the money from each contract that is out of the money. We also did not reflect master netting agreements and collateral for our derivatives. 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. 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 credit risk exposure is reflected in the net derivative asset and derivative liability amounts shown in the Total Net Fair Value column.

Increases and decreases in the gross components presented in each of the levels in this table 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

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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.

Equity securities consist of mutual funds, 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 the quarter and six months ended June 30, 2010, 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 Level 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.

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

	Quarter Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(In millions)			
Balance at beginning of period	**$ (315.2)**	$ (275.1)	**$ (291.5)**	$ 37.0
Realized and unrealized (losses) gains:				
Recorded in income	**58.0**	(99.8)	**(78.7)**	(247.2)
Recorded in other comprehensive income	**(2.8)**	114.6	**73.6**	23.9
Purchases, sales, issuances, and settlements	**7.4**	34.6	**16.6**	36.5
Transfers into Level 3[1]	**93.0**		**208.0**	
Transfers out of Level 3[1]	**(16.1)**		**(103.7)**	
Net transfers into and out of Level 3	**76.9**	49.2	**104.3**	(26.7)
Balance at end of period	**$ (175.7)**	$ (176.5)	**$ (175.7)**	$ (176.5)
Change in unrealized gains recorded in income relating to derivatives still held at end of period	**$ 82.9**	$ 71.0	**$ 8.9**	$ 99.6

1 Effective January 1, 2010, we are required to present separately the amounts transferred into Level 3 from the amounts transferred out of Level 3. For purposes of this reconciliation, we assumed transfers into and out of Level 3 occurred on the last day of the quarter.

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* to our 2009 Annual Report on Form 10-K.

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 June 30, 2010	**Carrying Amount**	**Fair Value**
	(In millions)	
Investments and other assets Constellation Energy	**$ 184.4**	**$ 184.6**
Fixed-rate long-term debt:		
Constellation Energy (including BGE)	**3,707.8**	**4,084.8**
BGE	**2,172.0**	**2,366.9**
Variable-rate long-term debt:		
Constellation Energy (including BGE)	**544.1**	**544.1**
BGE		

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

cash and cash equivalents, net accounts receivable, 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.

Accounting Standards Adopted

Accounting for Variable Interest Entities

In June 2009, the Financial Accounting Standards Board amended the accounting, presentation, and disclosure guidance related to variable interest entities. We adopted this guidance on January 1, 2010 and discuss our adoption in more detail beginning on page 10.

Related Party Transactions

Constellation Energy

CENG

On November 6, 2009, upon the sale of a membership interest in CENG, our nuclear generation and operation business, to EDF, we deconsolidated CENG and began accounting for our 50.01% membership interest in CENG as an equity method investment.

In connection with the closing of the transaction with EDF, we entered into a power purchase agreement (PPA) with CENG with an initial fair value of $0.8 billion under which we will purchase between 85-90% of the output of CENG's nuclear plants that is not sold to third parties under pre-existing PPAs over the five year term of the PPA.

In addition to the PPA, we entered into a power services agency agreement (PSA) and an administrative

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service agreement (ASA). 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 is a one year agreement that is renewable annually under which we will provide administrative support services to CENG for a fee of approximately $66 million for 2010. The fees for administrative support services will be subject to change in future years based on the level of services provided. The charges under this agreement are intended to represent the actual cost of the services provided to CENG from us.

The impact of transactions under these agreements is summarized below:

Agreement	Amount Recognized in Earnings for the Quarter Ended June 30, 2010	Amount Recognized in Earnings for the Six Months Ended June 30, 2010	Income Statement Classification	Accounts Receivable/ (Accounts Payable) at June 30, 2010
		(In millions)		
PPA	$ 222.1	$ 420.6	Fuel and purchased energy expenses	$ (49.6)
PSA	(4.0)	(8.0)	Nonregulated revenues	
ASA	(16.5)	(33.0)	Operating expenses	5.5

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 September 30, 2012.

The cost of BGE's purchased energy from nonregulated subsidiaries of Constellation Energy to meet its standard offer service obligation was as follows:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
		(In millions)		
Purchased energy	**$ 114.6**	$ 142.5	**$ 238.6**	$ 346.8

In addition, Constellation Energy charges BGE for the costs of certain corporate functions. These costs are comprised of direct charges as well as costs that are allocated 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. Under the Maryland PSC's October 30, 2009 order approving the transaction with EDF, we are limited to allocating no more than 31% of these costs to BGE.

The following table presents all of the costs Constellation Energy charged to BGE in each period, both directly-charged and allocated.

	Quarter Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
		(In millions)		
Charges to BGE	**$ 42.3**	$ 35.5	**$ 78.5**	$ 65.1

Other nonregulated affiliates of BGE also charge BGE for the costs of certain services provided.

BGE Balance Sheet

Throughout 2009, 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. Under this arrangement, BGE had invested $314.7 million at December 31, 2009.

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.

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Item 2. Management's Discussion

Management's Discussion and Analysis of Financial Condition and Results of Operations

Introduction and Overview

Constellation Energy Group, Inc. (Constellation Energy) is an energy company that includes a generation business (Generation), a customer supply business (NewEnergy), and Baltimore Gas and Electric Company (BGE). We describe our operating segments in the *Notes to Consolidated Financial Statements* on page 14.

This Quarterly Report on Form 10-Q is a combined report of Constellation Energy and BGE. References in this report to "we" and "our" are to Constellation Energy and its subsidiaries, collectively. References in this report to the "regulated business(es)" are to BGE. We discuss our business and strategy in more detail in *Item 1 Business* section of our 2009 Annual Report on Form 10-K and we discuss the risks affecting our business in *Item 1A. Risk Factors* section of our 2009 Annual Report on Form 10-K.

Our 2009 Annual Report on Form 10-K includes a detailed discussion of various items impacting our business, our results of operations, and our financial condition. These include:

- *Introduction and Overview* section which provides a description of our business,
- *Strategy* section,
- *Business Environment* section, including how recent events, regulation, weather, and other factors affect our business, and
- *Critical Accounting Policies* section.

Critical accounting policies are the accounting policies that are most important to the portrayal of our financial condition and results of operations and that require management's most difficult, subjective, or complex judgment. Our critical accounting policies include derivative accounting and the evaluation of assets for impairment and other than temporary decline in value.

In this discussion and analysis, we explain the general financial condition and the results of operations for Constellation Energy and BGE including:

- factors which affect our businesses,
- our earnings and costs in the periods presented,
- changes in earnings and costs between periods,
- sources of earnings,
- impact of these factors on our overall financial condition,
- expected future expenditures for capital projects,
- expected sources of cash for future capital expenditures, and
- our net available liquidity and collateral requirements.

As you read this discussion and analysis, refer to our Consolidated Statements of Income (Loss) on page 2, which present the results of our operations for the quarters and six months ended June 30, 2010 and 2009. We analyze and explain the differences between periods in the specific line items of the Consolidated Statements of Income (Loss).

We have organized our discussion and analysis as follows:

We describe changes to our business environment during the year.

We highlight significant events that occurred in 2010 that are important to understanding our results of operations and financial condition.

We then review our results of operations beginning with an overview of our total company results, followed by a more detailed review of those results by operating segment. As of January 1, 2010, we changed our reportable segments and have recast prior period information to conform with the current presentation.

We review our financial condition, addressing our sources and uses of cash, capital resources, commitments, and liquidity.

We conclude with a discussion of our exposure to various market risks.

Business Environment

Various factors affect our financial results. We discuss these various factors in the *Forward Looking Statements* section on page 69 and in *Item 1A. Risk Factors* section of our 2009 Annual Report on Form 10-K. We discuss our market risks in the *Risk Management* section beginning on page 63.

The volatility of the financial, credit and global energy markets impacts our liquidity and collateral requirements as well as our credit risk. We discuss our liquidity and collateral requirements in the *Financial Condition* section and our customer (counterparty) credit and other risks in more detail in the *Risk Management* section.

In this section, we discuss in more detail events which have impacted our business during 2010.

Regulation Maryland

In May 2010, BGE filed an application for a $46.9 million and a $42.4 million increase in our electric and gas base rates, respectively, with the Maryland Public Service Commission (Maryland PSC). While BGE demonstrated the need for a $110.8 million increase in electric base rates, distribution revenues awarded to BGE in the case are

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subject to a 5% cap pursuant to the terms of the 2008 settlement agreement with the State of Maryland as well as the Maryland PSC's order approving the EDF transaction. In the application, we requested an 8.99% rate of return with an 11.65% return on equity. The Maryland PSC is currently reviewing our application and is expected to issue a ruling in December 2010. We cannot provide assurance that the Maryland PSC will approve the base rate increases requested, or if it does, that it will grant BGE the full amounts requested.

In June 2010, the Maryland PSC issued an order rejecting BGE's smart grid initiative proposal as originally filed. In July 2010, BGE filed an application for a rehearing of an amended smart grid proposal. We discuss the status of BGE's smart grid proposal in more detail in the Capital Requirements section on page 62.

Federal Regulation

Financial Regulatory Reform

The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) was enacted in July 2010. While the Dodd-Frank Act is focused primarily on the regulation and oversight of financial institutions, it also provides for a new regulatory regime for derivatives, including mandatory clearing of certain swaps, exchange trading, margin requirements, and other transparency requirements. The Dodd-Frank Act, however, also preserves the ability of end users in our industry to hedge their risks, which we believe results in the new derivatives requirements not being applicable to us for most of our activities. However, there will be several key rulemakings to implement the derivatives requirements, which, depending on the final scope of the regulations, could attempt to impose significant obligations on us nonetheless. Final regulations may address collateral requirements and exchange margin cash postings, which if applicable to us despite being an end user of derivatives, could have the effect of increasing our collateral requirements or the amount of exchange margin cash postings in lieu of letters of credit currently issued on over-the-counter contracts. These regulations could also result in additional transactional and compliance costs to the extent they apply to us, and could impact market liquidity.

In addition to new regulation over derivatives, the Dodd-Frank Act amends the Sarbanes-Oxley Act to permanently exempt nonaccelerated filers, including BGE, from the requirement to obtain an audit report on internal control over financial reporting.

Environmental Matters

Air Quality

Federal

National Ambient Air Quality Standards (NAAQS)

In January 2010, the U.S. Environmental Protection Agency (EPA) proposed rules to adopt NAAQS for ozone that are stricter than the NAAQS adopted in March 2008, based on the EPA's reevaluation of scientific evidence about ozone and ozone's effects on humans and the environment. In June 2010, the EPA adopted a stricter NAAQS for sulfur dioxide (SO_2). We are unable to determine the impact that complying with the stricter NAAQS for ozone or sulfur dioxide will have on our financial results until the states in which our generating facilities are located adopt plans to meet the new standards. However, costs associated with compliance with these plans could be material.

In July 2010, the EPA proposed regulations to replace the regional cap-and-trade program under the Clean Air Interstate Rule (CAIR) with a program that would require each of 31 eastern states and the District of Columbia to reduce SO_2 and nitrogen oxide (NO_X) emissions. Depending on the scope of any final regulations that may be adopted by the EPA and any plans that may be adopted by the states in which our plants are located, additional regulation could result in additional compliance requirements and costs that could be material.

State

The State of Maryland has adopted opacity regulations consistent with its commitment to resolve long-standing industry concerns about the prior regulations' continuous compliance requirements and is in the process of obtaining the EPA's approval of Maryland's state implementation plan (SIP) for these regulations. While EPA approval of Maryland's SIP is being obtained, the opacity regulations are being implemented in a manner that will enable our plants to remain in compliance. We anticipate that the regulations under the EPA-approved SIP will be consistent with the regulations as currently implemented.

Water Quality

Water Intake Regulations

In March 2010, the New York Department of Environmental Conservation issued a draft policy designating closed-cycle cooling as the best technology available for cooling water intake structures for minimizing adverse environmental impacts. At this time we cannot predict whether this policy will be adopted. However, if the policy is adopted and CENG is required to retrofit its two nuclear generating facilities in New York to implement this technology, our share of the compliance costs could be material.

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Hazardous and Solid Waste

In May 2010, the EPA proposed rules to regulate coal combustion by-products, such as fly ash, either as a special hazardous waste or as a nonhazardous waste. Depending on the scope of any final rules that are adopted, additional federal regulation has the potential to result in additional compliance requirements and costs that could be material.

Accounting Standards Adopted

We discuss recently adopted accounting standards in the *Accounting Standards Adopted* section of the *Notes to Consolidated Financial Statements* on page 37.

Events of 2010

Acquisitions

Criterion Wind Project

In April 2010, we completed the acquisition of the Criterion wind project in Garrett County, Maryland.

Texas Combined Cycle Generation Facilities

In May 2010, we acquired 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.

We discuss these transactions in more detail beginning on page 12 in *Notes to Consolidated Financial Statements.*

Hillabee Energy Center

In June 2010, the Hillabee Energy Center, a 740 MW gas-fired combined cycle power generation facility located in Alabama began commercial dispatch. We had acquired this facility in 2008.

Divestiture

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.

In August 2010, we completed the sale of our interests in the Mammoth Lakes geothermal generating facility.

We discuss these transactions in more detail on page 13 in *Notes to Consolidated Financial Statements.*

Redemption of Notes

In February 2010, we retired certain of our 7.00% Notes due April 1, 2012 as part of a cash tender offer launched in January 2010 and in March 2010 we repurchased certain tax exempt notes. We discuss these transactions in more detail on page 17 in *Notes to Consolidated Financial Statements*.

Healthcare Reform Legislation

In March 2010, the Patient Protection and Affordable Care Act and the Healthcare and Education Reconciliation Act of 2010 (Reconciliation Act) were signed into law. We discuss the impact of these new laws on our earnings for the six months ended June 30, 2010 in more detail on page 16 in *Notes to Consolidated Financial Statements*.

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Results of Operations for the Quarter and Six Months Ended June 30, 2010 Compared with the Same Periods of 2009

In this section, we discuss our earnings and the factors affecting them. We begin with a general overview, then separately discuss earnings for our operating segments. Significant changes in other (expense) income, fixed charges, and income taxes are discussed, as necessary, in the aggregate for all segments in the *Consolidated Nonoperating Income and Expenses* section on page 57.

Overview

Results

	Quarter Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(In millions, after-tax)			
Generation	**$ 15.3**	$ 62.1	**$ 42.4**	$ 103.6
NewEnergy	**50.8**	(46.1)	**154.9**	(292.4)
Regulated electric	**20.9**	22.1	**48.1**	67.5
Regulated gas	**(3.9)**	(6.2)	**33.3**	33.4
Other nonregulated	**0.7**	(3.6)	**(3.6)**	(3.5)
Net Income (Loss)	**$ 83.8**	$ 28.3	**$ 275.1**	$ (91.4)
Net Income (Loss) attributable to common stock	**$ 72.6**	$ 8.1	**$ 264.1**	$ (115.4)
Change from prior year	**$ 64.5**		**$ 379.5**	

Our total net income (loss) attributable to common stock for the quarter and six months ended June 30, 2010 was favorable compared to net income (loss) attributable to common stock for the same periods of 2009 by $64.5 million and $379.5 million, respectively, primarily due to the following:

	Quarter Ended June 30,	Six Months Ended June 30,
	2010 vs. 2009	
	(In millions, after-tax)	
Generation gross margin	$ (140)	$ (272)
NewEnergy gross margin	(16)	97
Generation operating expenses, primarily labor and benefit costs due to the deconsolidation of CENG	95	195
Gain on NewEnergy international coal contract assignments[1]	10	48
Generation accretion of asset retirement obligations due to deconsolidation of CENG	11	21
NewEnergy hedge ineffectiveness	(41)	(47)
Regulated businesses	1	(16)
Other nonregulated businesses	1	2
Total change in *Other Items included in Operations* per table below	137	312
All other changes	7	40
Total Change	$ 65	$ 380

1 Subsequent to June 30, 2010, we assigned an international freight contract incurring an approximately $42 million after-tax loss. This transaction will be recorded in the third quarter of 2010.

Other Items Included in Operations (after-tax)[1]:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(In millions, after-tax)			
Deferred income tax expense relating to federal subsidies for providing post-employment prescription drug benefits	**$**	$	**$ (8.8)**	$
Loss on early retirement of 2012 Notes			**(30.9)**	
Amortization of basis difference in CENG	**(37.0)**		**(62.7)**	
Impact of power purchase agreement with CENG[2]	**(29.1)**		**(54.8)**	
International commodities operation and gas trading operation[3]		(123.8)		(308.0)
Impairment losses and other costs		(65.4)		(76.6)
Impairment of nuclear decommissioning trust assets		(6.1)		(29.8)
Merger termination and strategic alternatives costs		(4.0)		(46.3)
Workforce reduction costs		(1.1)		(5.3)
Credit facility amendment fees	**(2.9)**	(5.2)	**(5.8)**	(8.9)
Total Other Items	**$ (69.0)**	$ (205.6)	**$ (163.0)**	$ (474.9)
Change from prior year	**$ 136.6**		**$ 311.9**	

1 Amounts for the quarter ended June 30, 2009 include income tax adjustments relating to activity during the quarter ended March 31, 2009 based on updated estimates of our 2009 annual effective tax rate.

2 The net impact to the Company of the power purchase agreement with CENG was $47.7 million and $89.9 million pre-tax for the quarter and six months ended June 30, 2010. This amount represents the amortization of our "Unamortized energy contract asset" less our 50.01% equity in CENG's amortization of its "Unamortized energy contract liability."

3 These amounts include the net losses on the sales of the international commodities operation, gas trading operation, certain other trading operations, and a uranium market participant, the reclassification of losses on previously designated cash-flow hedges from Accumulated Other Comprehensive Loss because the forecasted transactions are probable of not occurring, and earnings that are no longer part of our core business. The impairment losses and other costs and workforce reduction costs line items also include amounts related to the operations we divested.

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In the following sections, we discuss our earnings by business segment in greater detail.

Generation Business

Background

We define our Generation business in the *Notes to Consolidated Financial Statements* on page 14.

We present the results of this business based on the assumption that we have hedged 100% of generation output and fuel for generation. The assumption is based on executing hedges at prevailing market prices with the NewEnergy business. Taking into account previously executed hedges at the end of each fiscal year, we ensure that the Generation business is fully hedged by the NewEnergy business for the next year. Therefore, all commodity price risk is managed by and presented in the results of our NewEnergy business as discussed below. Generally, changes in the results of our Generation business during the period are due to changes in the level of output from the generating assets.

Results

	Quarter Ended June 30,		Six Months Ended June 30,	
	2010	**2009**	**2010**	**2009**
		(In millions)		
Revenues	**$ 550.3**	$ 682.5	**$ 1,130.2**	$ 1,468.0
Fuel and purchased energy expenses	**(343.8)**	(166.5)	**(670.4)**	(388.4)
Gross margin	**206.5**	516.0	**459.8**	1,079.6
Operating expenses	**(90.0)**	(259.7)	**(184.6)**	(541.3)
Merger termination and strategic alternatives costs		(2.9)		(29.3)
Depreciation, depletion, and amortization	**(31.6)**	(45.9)	**(59.7)**	(91.0)
Accretion of asset retirement obligations	**(0.4)**	(18.1)	**(0.8)**	(36.0)
Taxes other than income taxes	**(5.6)**	(18.5)	**(11.0)**	(36.7)
Net gain (loss) on divestitures			**2.9**	
Equity investment losses:				
CENG	**(21.3)**		**(40.6)**	
UNE	**(6.8)**		**(12.9)**	
Other	**(5.4)**		**(0.7)**	
Income from Operations	**$ 45.4**	$ 170.9	**$ 152.4**	$ 345.3
Net Income	**$ 15.3**	$ 62.1	**$ 42.4**	$ 103.6
Net Income attributable to common stock	**$ 15.3**	$ 62.1	**$ 42.4**	$ 103.6
Other Items Included in Operations (after-tax)[1]:				
Deferred income tax expense relating to federal subsidies for providing post-employment prescription drug benefits	**$**	$	**$ (0.8)**	$
Loss on early retirement of 2012 Notes			**(30.9)**	
Amortization of basis difference in CENG	**(37.0)**		**(62.7)**	
Impact of power purchase agreement with CENG[2]	**(29.1)**		**(54.8)**	
Impairment of nuclear decommissioning trust assets		(6.1)		(29.9)
Merger termination and strategic alternatives costs		(2.9)		(29.3)
Credit facility amendment fees	**(1.9)**	(3.1)	**(3.8)**	(5.4)
Total Other Items	**$ (68.0)**	$ (12.1)	**$ (153.0)**	$ (64.6)

Above amounts include intercompany transactions eliminated in our Consolidated Financial Statements. The Information by Operating Segment section within the Notes to Consolidated Financial Statements on page 15 provides a reconciliation of operating results by segment to our Consolidated Financial Statements.

1 Amounts for the quarter ended June 30, 2009 include income tax adjustments relating to activity during the quarter ended March 31, 2009 based on updated estimates of our 2009 annual effective tax rate.

2 The net impact to the Company of the power purchase agreement with CENG was $47.7 million and $89.9 million pre-tax for the quarter and six months ended June 30, 2010. This amount represents the amortization of our "Unamortized energy contract asset" less our 50.01% equity in CENG's amortization of its "Unamortized energy contract liability."

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Effects of Transaction with EDF on Consolidated Statement of Income (Loss)

Prior to November 6, 2009, Constellation Energy Nuclear Group, LLC (CENG), our nuclear generation and operation business, was a 100% owned consolidated subsidiary. On November 6, 2009, we completed the sale of a 49.99% membership interest in CENG to EDF Group and affiliates (EDF), and we deconsolidated CENG. Specifically, we removed the assets and liabilities of CENG and recorded an investment in CENG at fair value on our Consolidated Balance Sheets, and recorded the proceeds received on our Consolidated Statements of Cash Flows. After November 6, 2009, we record equity investment earnings from CENG on our Consolidated Statements of Income (Loss). We discuss our transaction with EDF in more detail in *Note 2* to our 2009 Annual Report on Form 10-K.

Revenues

Our Generation revenues decreased $132.2 million and $337.8 million in the quarter and six months ended June 30, 2010 compared to the same periods of 2009, primarily due to the following:

	Quarter Ended June 30, 2010 vs. 2009	Six Months Ended June 30, 2010 vs. 2009
	(In millions)	
Decrease in volume of output from nuclear generating assets due to the deconsolidation of CENG	**$ (104)**	$ (263)
Decrease due to higher outages at our fossil plants	**(16)**	(77)
All other	**(12)**	2
Total decrease in Generation revenues	**$ (132)**	$ (338)

Fuel and Purchased Energy Expenses

Our Generation fuel and purchased energy expenses increased $177.3 million and $282.0 million in the quarter and six months ended June 30, 2010 compared to the same periods of 2009, primarily due to the following:

	Quarter Ended June 30, 2010 vs. 2009	Six Months Ended June 30, 2010 vs. 2009
	(In millions)	
Increase in purchased energy costs due to power purchase agreement with CENG compared with nuclear fuel costs in 2009	**$ 177**	$ 337
Increase in fuel costs due to higher coal prices	**24**	24
Decrease due to higher outages at our fossil plants	**(16)**	(56)
All other	**(8)**	(23)
Total increase in Generation fuel and purchased energy expenses	**$ 177**	$ 282

Operating Expenses

Our Generation business operating expenses decreased $169.7 million for the quarter ended June 30, 2010 as compared to the same period for 2009 due to lower labor and benefit costs of $126.1 million and lower non-labor operating expenses of $43.6 million, the majority of which results from the absence of costs in 2010 due to the deconsolidation of CENG in 2009.

Our Generation business operating expenses decreased $356.7 million for the six months ended June 30, 2010 as compared to the same period for 2009 due to lower labor and benefit costs of $272.3 million and lower non-labor operating expenses of $84.4 million, the majority of which results from the absence of costs in 2010 due to the deconsolidation of CENG in 2009.

Depreciation, Depletion and Amortization Expense

Our Generation business incurred lower depreciation, depletion and amortization expenses of $14.3 million during the quarter ended June 30, 2010 compared to the same period of 2009 primarily due to a decrease of $27.6 million in depreciation on the nuclear generating facilities resulting from the deconsolidation of CENG in 2009, partially offset by an increase of $13.3 million in depreciation on our other generating facilities primarily related to environmental additions at our Brandon Shores

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coal-fired generating plant that went into service in the fourth quarter of 2009.

Our Generation business incurred lower depreciation, depletion and amortization expenses of $31.3 million during the six months ended June 30, 2010 compared to the same period of 2009 primarily due to a decrease of $54.4 million in depreciation on the nuclear generating facilities resulting from the deconsolidation of CENG in 2009, partially offset by an increase of $23.1 million in depreciation on our other generating facilities primarily related to environmental additions at our Brandon Shores coal-fired generating plant that went into service in the fourth quarter of 2009.

Accretion of Asset Retirement Obligations

Our Generation business incurred lower accretion of asset retirement obligations of $17.7 million and $35.2 million during the quarter and six months ended June 30, 2010, respectively, compared to the same periods of 2009 primarily as a result of the deconsolidation of CENG. The majority of our asset retirement obligations in 2009 related to the nuclear generating facilities owned by CENG.

Taxes Other Than Income Taxes

Taxes other than income taxes decreased $12.9 million and $25.7 million during the quarter and six months ended June 30, 2010, respectively, compared to the same periods of 2009 primarily due to a reduction in property taxes as a result of the deconsolidation of CENG, which included the removal of five nuclear generating facilities from our total assets.

Equity Investment Losses

During the fourth quarter of 2009, after the formation of the CENG joint venture, we separately presented all of our equity investment losses. Prior to the fourth quarter of 2009, our equity investment losses were recorded in "Nonregulated revenues" on our Consolidated Statements of Income (Loss).

CENG is involved in discussions with certain tax jurisdictions in New York State with respect to agreements covering property tax payments on the Nine Mile Point nuclear generating facility. These discussions may result in an increase in future property tax expenses for CENG, which in turn would reduce our equity investment earnings in CENG based on our 50.01% ownership interest. We are unable to determine the outcome of these discussions at this time.

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NewEnergy Business

Background

We define our NewEnergy business in the *Notes to Consolidated Financial Statements* on page 14.

Our NewEnergy business focuses on delivery of physical, customer-oriented energy products and services to energy producers and consumers, manages the risk and optimizes the value of our owned generation assets and NewEnergy activities, and uses our portfolio management and trading capabilities both to manage risk and to deploy risk capital. Our NewEnergy business actively transacts in energy and energy-related commodities in order to manage our portfolio of energy purchases and sales to customers through structured transactions.

We record NewEnergy revenues and expenses in our financial results in different periods depending upon the accounting treatment that we believe provides the most transparent presentation of the economics of the underlying transactions in our business. We discuss our revenue recognition policies in the *Critical Accounting Policies* section and *Note 1* of our 2009 Annual Report on Form 10-K.

As part of managing our total portfolio risk, we use economic value at risk. We view economic value at risk as the most comprehensive measure of our exposure to changing commodity prices. This metric measures the risk in our total portfolio, encompassing all aspects of our NewEnergy business. We also use daily value at risk and stop loss limits and liquidity guidelines to restrict the level of risk in our portfolio. We discuss the impact of our economic value at risk and value at risk in more detail in the *Mark-to-Market* and *Risk Management* sections.

Results

	Quarter Ended June 30,		Six Months Ended June 30,	
	2010	**2009**	**2010**	**2009**
		(In millions)		
Revenues	**$ 2,390.8**	$ 2,978.1	**$ 4,741.7**	$ 5,992.9
Fuel and purchased energy expenses	**(2,085.3)**	(2,577.3)	**(4,064.7)**	(5,538.1)
Gross margin	**305.5**	400.8	**677.0**	454.8
Operating expenses	**(190.6)**	(194.7)	**(359.1)**	(383.3)
Merger termination and strategic alternatives costs		(1.1)		(17.0)
Impairment losses and other costs		(60.5)		(89.1)
Workforce reduction costs		(0.4)		(11.2)
Depreciation, depletion, and amortization	**(20.9)**	(21.0)	**(42.6)**	(41.2)
Accretion of asset retirement obligations		(0.1)	**(0.1)**	(0.1)
Taxes other than income taxes	**(13.7)**	(8.3)	**(26.6)**	(19.5)
Net gain (loss) on divestitures	**0.2**	(129.6)	**2.2**	(464.1)
Income (Loss) from Operations	**$ 80.5**	$ (14.9)	**$ 250.8**	$ (570.7)
Net Income (Loss)	**$ 50.8**	$ (46.1)	**$ 154.9**	$ (292.4)
Net Income (Loss) attributable to common stock	**$ 42.9**	$ (62.9)	**$ 150.5**	$ (309.7)
Other Items Included in Operations (after-tax)[1]:				
Deferred income tax expense relating to federal subsidies for providing post-employment prescription drug benefits	**$**	$	**$ (0.1)**	$
International commodities operation and gas trading operation[2]		(123.8)		(308.0)
Impairment losses and other costs		(62.1)		(73.4)
Merger termination and strategic alternatives costs		(1.1)		(17.0)
Workforce reduction costs		(1.1)		(5.3)
Credit facility amendment fees	**(1.0)**	(2.1)	**(2.0)**	(3.5)
Total Other Items	**$ (1.0)**	$ (190.2)	**$ (2.1)**	$ (407.2)

Above amounts include intercompany transactions eliminated in our Consolidated Financial Statements. The Information by Operating Segment section within the Notes to Consolidated Financial Statements on page 15 provides a reconciliation of operating results by segment to our Consolidated Financial Statements.

1 Amounts for the quarter ended June 30, 2009 include income tax adjustments relating to activity during the quarter ended March 31, 2009 based on updated estimates of our 2009 annual effective tax rate.

2 These amounts include the net losses on the sales of the international commodities operation, gas trading operation, certain other trading operations, and a uranium market participant, the reclassification of losses on previously designated cash-flow hedges from Accumulated Other Comprehensive Loss because the forecasted transactions are probable of not occurring, and earnings that are no longer part of our core business. The impairment losses and other costs and workforce reduction costs line items also include amounts related to the operations we divested.

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Revenues

Our NewEnergy revenues decreased $587.3 million and $1,251.2 million in the quarter and six months ended June 30, 2010 compared to the same periods of 2009, primarily due to the following:

	Quarter Ended June 30, 2010 vs. 2009	Six Months Ended June 30, 2010 vs. 2009
	(In millions)	
Realization of lower volumes of wholesale load sales	$ (436)	$ (939)
Decrease in volume and contract prices related to our domestic coal operation	(145)	(260)
Decrease due to the absence of revenues at our international coal and freight operations, which we divested in 2009	(117)	(128)
Change in wholesale mark-to-market revenues due to more favorable changes in power and gas prices	80	114
Absence of gain on sale of in-the-money wholesale load contract in 2009	(106)	(106)
Realization of higher volumes of retail load sales	105	80
All other	32	(12)
Total decrease in NewEnergy revenues	$ (587)	$ (1,251)

Fuel and Purchased Energy Expenses

Our NewEnergy fuel and purchased energy expenses decreased $492.0 million and $1,473.4 million in the quarter and six months ended June 30, 2010 compared to the same periods of 2009, primarily due to the following:

	Quarter Ended June 30, 2010 vs. 2009	Six Months Ended June 30, 2010 vs. 2009
	(In millions)	
Realization of lower volumes of wholesale power purchases	**$ (227)**	$ (775)
Decrease due to the absence of costs at our international coal and freight operations, which we divested in 2009	**(150)**	(278)
Decrease in volume and contract prices related to our domestic coal operation	**(117)**	(233)
Decrease in wholesale mark-to-market expenses due to the absence of losses on international coal purchase contracts, which we divested in 2009		(108)
Realization of lower volumes primarily due to the absence of costs at our gas trading operations, which we divested in 2009		(56)
All other	**2**	(23)
Total decrease in NewEnergy fuel and purchased energy expenses	**$ (492)**	$ (1,473)

Mark-to-Market

Mark-to-market results include net gains and losses from origination, risk management and trading activities for which we use the mark-to-market method of accounting. We discuss these activities and the mark-to-market method of accounting in more detail in the *Critical Accounting Policies* section of our 2009 Annual Report on Form 10-K.

The nature of our operations and the use of mark-to-market accounting for certain activities create fluctuations in mark-to-market earnings. We cannot predict these fluctuations, but the impact on our earnings could be material. We discuss our market risk in more detail in the *Risk Management* section beginning on page 63. The

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primary factors that cause fluctuations in our mark-to-market results are:

- changes in the level and volatility of forward commodity prices and interest rates,
- counterparty creditworthiness,
- the number and size of our open derivative positions, and
- the number, size, and profitability of new transactions, including termination or restructuring of existing contracts.

The primary components of mark-to-market results are origination gains and gains and losses from risk management and trading activities.

Origination gains arise primarily from contracts that our NewEnergy business structures to meet the risk management needs of our customers or relate to our trading activities. Transactions that result in origination gains may be unique and provide the potential for individually significant revenues and gains from a single transaction. We did not record any origination gains during the quarters and six months ended June 30, 2010 and 2009.

Risk management and trading mark-to-market represents both realized and unrealized gains and losses from changes in the value of our portfolio, including the effects of changes in valuation adjustments. In addition to our fundamental risk management and trading activities, we also use non-trading derivative contracts subject to mark-to-market accounting to manage our exposure to changes in market prices, while in general the underlying physical transactions related to these activities are accounted for on an accrual basis.

We discuss the changes in mark-to-market results below. We show the relationship between our mark-to-market results and the change in our net mark-to-market energy asset later in this section.

Mark-to-market results were as follows:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2010	**2009**	**2010**	**2009**
		(In millions)		
Unrealized mark-to-market results				
Origination gains	**$**	$	**$**	$
Risk management and trading mark-to-market				
Unrealized changes in fair value	**47.1**	(22.5)	**10.9**	(217.0)
Changes in valuation techniques				
Reclassification of settled contracts to realized	**(26.7)**	158.8	**(216.8)**	(157.9)
Total risk management and trading mark-to-market	**20.4**	136.3	**(205.9)**	(374.9)
Total unrealized mark-to-market*	**20.4**	136.3	**(205.9)**	(374.9)
Realized mark-to-market	**26.7**	(158.8)	**216.8**	157.9
Total mark-to-market results**	**$ 47.1**	$ (22.5)	**$ 10.9**	$ (217.0)

** Total unrealized mark-to-market is the sum of origination gains and total risk management and trading mark-to-market.*

*** Includes gains (losses) on hedge ineffectiveness for fair value hedges recorded in gross margin.*

Total mark-to-market results increased $69.6 million during the quarter ended June 30, 2010 compared to the same period of 2009 primarily due to unrealized changes in fair value due to:

$46 million of higher results on open positions primarily due to the absence of losses in our power and transmission risk management activities in the PJM, New England, and New York regions as a result of a more favorable price environment and completion of our activities to reduce risk and improve liquidity,

$9 million of higher results in our domestic coal portfolio due to the absence of losses that resulted from a less favorable price environment in the second quarter of 2009,

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$9 million of higher results due to the absence of losses in our international coal and freight operations which were divested in 2009, and

$6 million of higher results related to our emissions trading activities primarily as a result of declining prices due to an uncertain regulatory environment.

Total mark-to-market results increased $227.9 million during the six months ended June 30, 2010 compared to the same period of 2009 due to unrealized changes in fair value primarily due to:

$218 million of higher results on open positions primarily due to the absence of losses in our power and transmission risk management activities in the PJM, New England, and New York regions as a result of a more favorable price environment and completion of our activities to reduce risk and improve liquidity,

$16 million of higher results in our domestic coal portfolio due to the absence of losses that resulted from a less favorable price environment in 2009, and

$4 million of higher results related to our emissions trading activities primarily as a result of lower write-downs of our emissions allowance inventory.

These increases were partially offset by the following:

$6 million of lower results due to the absence of our international coal and freight operations as a result of its divestiture in 2009, and

$4 million of lower gains due to the absence of our wholesale natural gas risk management and trading operation primarily as a result of the divestiture of our natural gas trading operation in 2009.

Derivative Assets and Liabilities

Derivative assets and liabilities, excluding $197.3 million and $348.7 million of exchange-traded derivatives classified as accounts receivable at June 30, 2010 and December 31, 2009, respectively, consisted of the following:

	June 30, 2010	**December 31, 2009**
	(In millions)	
Current Assets	**$ 558.2**	$ 639.1
Noncurrent Assets	**550.2**	633.9
Total Assets	**1,108.4**	1,273.0
Current Liabilities	**621.6**	632.6
Noncurrent Liabilities	**633.0**	674.1
Total Liabilities	**1,254.6**	1,306.7
Net Derivative Position	**$ (146.2)**	$ (33.7)
Composition of net derivative position:		
Hedges	**$ (669.3)**	$ (591.0)
Mark-to-market	**422.1**	524.3
Net cash collateral included in derivative balances	**101.0**	33.0

Net Derivative Position	**$ (146.2)**	$ (33.7)

Derivative balances above include noncurrent assets related to our Generation business of $44.0 million and $35.8 million at June 30, 2010 and December 31, 2009, respectively. Derivative balances related to our Generation business consist of interest rate contracts accounted for as fair value hedges. We discuss our derivative assets and liabilities in further detail in the Notes to Consolidated Financial Statements.

As discussed in the *Critical Accounting Policies* section of our 2009 Annual Report on Form 10-K, our "Derivative assets and liabilities" include contracts accounted for as hedges and those accounted for on a mark-to-market basis. These amounts are presented in our Consolidated Balance Sheets after the impact of legally binding master netting agreements. Due to the impacts of commodity prices, the number of open positions, master netting arrangements, and offsetting risk positions on the presentation of our derivative assets and liabilities in our Consolidated Balance Sheets, we believe an evaluation of the net position is the most relevant measure, and is discussed in more detail below.

The increase in our net derivative liability subject to hedge accounting since December 31, 2009 of $78.3 million was due primarily to $395 million of increases on our out-of-the-money cash-flow hedge positions primarily related to decreases in power and natural gas prices during 2010, partially offset by $317 million of

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realization of out-of-the-money cash-flow hedges of wholesale and retail load obligations.

The following are the primary sources of the change in our net derivative asset subject to mark-to-market accounting during the quarter and six months ended June 30, 2010:

	Quarter Ended June 30, 2010	Six Months Ended June 30, 2010
	(in millions)	
Fair value beginning of period	$ 604.8	$ 524.3
Changes in fair value recorded in earnings		
Origination gains	$	$
Unrealized changes in fair value	47.1	10.9
Changes in valuation techniques		
Reclassification of settled contracts to realized	(26.7)	(216.8)
Total changes in fair value	20.4	(205.9)
Changes in value of exchange-listed futures and options	(179.1)	(7.0)
Net change in premiums on options	(51.9)	51.1
Contracts acquired		
Dedesignated contracts and other changes in fair value	27.9	59.6
Fair value at end of period	$ 422.1	$ 422.1

Changes in our net derivative asset that affected earnings were as follows:

Origination gains represent the initial unrealized fair value at the time these contracts are executed to the extent permitted by applicable accounting rules.

Unrealized changes in fair value represent unrealized changes in commodity prices, the volatility of options on commodities, the time value of options, and other valuation adjustments.

Changes in valuation techniques represent improvements in estimation techniques, including modeling and other statistical enhancements used to value our portfolio to more accurately reflect the economic value of our contracts.

Reclassification of settled contracts to realized represents the portion of previously unrealized amounts settled during the period and recorded as realized revenues.

The net derivative asset also changed due to the following items recorded in accounts other than in our Consolidated Statements of Income (Loss):

Changes in value of exchange-listed futures and options are adjustments to remove unrealized revenue from exchange-traded contracts that are included in risk management revenues. The fair value of these contracts is recorded in "Accounts receivable" rather than "Derivative assets" in our Consolidated Balance Sheets because these amounts are settled through our margin account with a third-party broker.

Net changes in premiums on options reflects the accounting for premiums on options purchased as an increase in the net derivative asset and premiums on options sold as a decrease in the net derivative asset.

Contracts acquired represents the initial fair value of acquired derivative contracts recorded in "Derivative assets and liabilities" in our Consolidated Balance Sheets.

Dedesignated contracts and other changes in fair value represent transfers of derivative contracts from cash flow hedges to mark-to-market treatment and those derivative contracts that did not meet the qualifications of cash flow hedge accounting.

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The settlement terms of the portion of our net derivative asset subject to mark-to-market accounting and sources of fair value based on the fair value hierarchy are as follows as of June 30, 2010:

	Settlement Term							
	2010	2011	2012	2013	2014	2015	Thereafter	Fair Value
	(In millions)							
Level 1	$ (2.0)	$	$	$	$	$	$	$ (2.0)
Level 2	138.2	385.6	143.0	(3.9)	2.3	1.1	1.3	667.6
Level 3	55.8	(110.8)	(188.6)	(18.6)	8.8	9.2	0.7	(243.5)
Total net derivative asset (liability) subject to mark-to-market accounting	$ 192.0	$ 274.8	$ (45.6)	$ (22.5)	$ 11.1	$ 10.3	$ 2.0	$ 422.1

Management uses its best estimates to determine the fair value of commodity and derivative contracts it holds and sells. These estimates consider various factors including closing exchange and over-the-counter price quotations, time value, volatility factors, and credit exposure. Additionally, because the depth and liquidity of the power markets varies substantially between regions and time periods, the prices used to determine fair value could be affected significantly by the volume of transactions executed. Future market prices and actual quantities will vary from those used in recording mark-to-market energy assets and liabilities, and it is possible that such variations could be material.

We manage our mark-to-market risk on a portfolio basis based upon the delivery period of our contracts and the individual components of the risks within each contract. Accordingly, we manage the energy purchase and sale obligations under our contracts in separate components based upon the commodity (e.g., electricity or gas), the product (e.g., electricity for delivery during peak or off-peak hours), the delivery location (e.g., by region), the risk profile (e.g., forward or option), and the delivery period (e.g., by month and year).

The electricity, fuel, and other energy contracts we hold have varying terms to maturity, ranging from contracts for delivery the next hour to contracts with terms of ten years or more. Because an active, liquid electricity futures market comparable to that for other commodities has not developed, many contracts are direct contracts between market participants and are not exchange-traded or financially settling contracts that can be readily offset in their entirety through an exchange or other market mechanism. Consequently, we and other market participants generally realize the value of these contracts as cash flows become due or payable under the terms of the contracts rather than through selling or liquidating the contracts themselves.

In order to realize the entire value of a long-term contract in a single transaction, we would need to sell or assign the entire contract. If we were to sell or assign any of our long-term contracts in their entirety, we may not realize the entire value reflected in the preceding table. However, based upon the nature of our operations, we expect to realize the value of these contracts, as well as any contracts we may enter into in the future to manage our risk, over time as the contracts and related hedges settle in accordance with their terms. Generally, we do not expect to realize the value of these contracts and related hedges by selling or assigning the contracts themselves in total.

Operating Expenses

Our NewEnergy business operating expenses decreased $4.1 million during the quarter ended June 30, 2010 as compared to the same period of 2009 primarily due to lower labor and benefit costs of $4.6 million related to the divestiture of our international commodities and gas trading operations in 2009 partially offset by higher non-labor operating expenses of $0.5 million.

Our NewEnergy business operating expenses decreased $24.2 million during the six months ended June 30, 2010 as compared to the same period of 2009 primarily due to lower labor and benefit costs of $18.4 million related to the divestiture of our international commodities and gas trading operations in 2009 and lower non-labor operating expenses of $5.8 million.

Taxes Other Than Income Taxes

Taxes other than income taxes increased $5.4 million during the quarter ended June 30, 2010 compared to the same period of 2009 primarily due to higher gross receipts taxes related to an increase in retail revenues, primarily in Pennsylvania.

Taxes other than income taxes increased $7.1 million during the six months ended June 30, 2010 compared to

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the same period of 2009 primarily due to $5.6 million of higher gross receipts taxes related to an increase in retail revenues, primarily in Pennsylvania, and $1.5 million of higher production taxes related to our upstream gas producing properties.

Net Gain (Loss) on Divestitures

The table below summarizes the net gain (loss) on divestitures for our NewEnergy business:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(In millions)			
Majority of our international commodities operation	$	$	$	$ (334.5)
Houston-based gas trading operation		(102.4)		(102.4)
Uranium market participant		(27.2)		(27.2)
Portfolio of contracts in our retail gas operations			2.0	
Other	0.2		0.2	
Total net gain (loss) on divestiture	$ 0.2	$ (129.6)	$ 2.2	$ (464.1)

We discuss the 2009 divestitures in more detail in *Note 2* of our 2009 Annual Report on Form 10-K.

Regulated Electric Business

Our regulated electric business is discussed in detail in *Item 1. Business Electric Business* section of our 2009 Annual Report on Form 10-K.

Results

	Quarter Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(In millions)			
Revenues	$ 651.1	$ 655.7	$ 1,402.4	$ 1,462.5
Electricity purchased for resale expenses	(401.4)	(402.5)	(875.0)	(927.7)
Operations and maintenance expenses	(107.4)	(103.9)	(221.2)	(195.0)
Depreciation and amortization	(49.6)	(55.0)	(106.0)	(110.5)
Taxes other than income taxes	(36.9)	(36.0)	(74.1)	(73.3)
Income from Operations	$ 55.8	$ 58.3	$ 126.1	$ 156.0
Net Income	$ 20.9	$ 22.1	$ 48.1	$ 67.5
Net Income attributable to common stock	$ 18.4	$ 19.5	$ 43.0	$ 62.4
Other Items Included in Operations (after-tax):				
Deferred income tax expense relating to federal subsidies for providing post-employment prescription drug benefits	$	$	$ (3.1)	$

Above amounts include intercompany transactions eliminated in our Consolidated Financial Statements. The Information by Operating Segment section within the Notes to Consolidated Financial Statements on page 15 provides a reconciliation of operating results by segment to our Consolidated Financial Statements.

Net income attributable to common stock from the regulated electric business decreased $19.4 million during the six months ended June 30, 2010 compared to the same period in 2009, primarily due to increased operations and maintenance expenses of $15.9 million after-tax and a decrease in revenues less electricity purchased for resale expenses of $4.5 million after-tax.

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Electric Revenues

The changes in electric revenues during the quarter and six months ended June 30, 2010 compared to the same periods of 2009 were caused by:

	Quarter Ended June 30, 2010 vs. 2009	Six Months Ended June 30, 2010 vs. 2009
	(In millions)	
Distribution volumes	$ 11.6	$ 10.3
Smart Energy Savers Program[SM] surcharges	(5.3)	(6.6)
Revenue decoupling	(11.1)	(11.1)
Standard offer service	0.5	(51.9)
Rate stabilization recovery	2.3	1.4
Financing credits	(0.1)	(0.2)
Senate Bill 1 credits	(3.4)	(3.4)
Total change in electric revenues from electric system sales	(5.5)	(61.5)
Other	0.9	1.4
Total change in electric revenues	$ (4.6)	$ (60.1)

Distribution Volumes

Distribution volumes are the amount of electricity that BGE delivers to customers in its service territory.

The percentage changes in our electric distribution volumes, by type of customer, in 2010 compared to 2009 were:

	Quarter Ended June 30, 2010 vs. 2009	Six Months Ended June 30, 2010 vs. 2009
Residential	15.4%	6.9%
Commercial	4.6	2.7
Industrial	(5.3)	(3.6)

During the quarter ended June 30, 2010 compared to the same period of 2009, we distributed more electricity to residential customers due to warmer weather, increased usage per customer, and an increased number of customers. We distributed more electricity to commercial customers due to increased usage per customer and an increased number of customers. We distributed less electricity to industrial customers primarily due to decreased usage per customer partially offset by an increased number of customers.

During the six months ended June 30, 2010 compared to the same period of 2009, we distributed more electricity to residential customers due to warmer weather, increased usage per customer, and an increased number of customers. We distributed more electricity to commercial customers due to increased usage per customer and an increased number of customers. We distributed less electricity to industrial customers primarily due to decreased usage per customer partially offset by an increased number of customers.

Smart Energy Savers Program[SM] Surcharges

Beginning in 2009, the Maryland PSC approved customer surcharges through which BGE recovers costs associated with certain programs designed to help BGE manage peak demand and encourage customer energy conservation.

Revenue Decoupling

The Maryland PSC has allowed us to record a monthly adjustment to our electric distribution revenues from residential and small commercial customers since 2008 and for the majority of our large commercial and industrial customers since February 2009 to eliminate the effect of abnormal weather and usage patterns per customer on our electric distribution volumes, thereby recovering a specified dollar amount of distribution revenues per customer, by customer class, regardless of changes in consumption levels. This means BGE recognizes revenues at

Maryland PSC-approved levels per customer, regardless of what actual distribution volumes were for a billing period. Therefore, while these revenues are affected by customer growth, they will not be affected by actual weather or usage conditions. We then bill or credit impacted customers in subsequent months for the difference between approved revenue levels under revenue decoupling and actual customer billings.

Standard Offer Service

BGE provides standard offer service for customers that do not select an alternative supplier. We discuss the provisions of Senate Bill 1 related to residential electric rates in the *Item 7. Management's Discussion and Analysis Business Environment Regulation Maryland Senate Bills 1 and 400* section of our 2009 Annual Report on Form 10-K.

Standard offer service revenues decreased during the six months ended June 30, 2010 compared to the same period of 2009 mostly due to a decrease in the standard offer service rates and lower standard offer service volumes.

Rate Stabilization Recovery

In late June 2007, BGE began recovering amounts deferred during the first rate deferral period that ended on May 31, 2007. The recovery of the first rate stabilization plan will

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occur over approximately ten years. In April 2008, BGE began recovering amounts deferred during the second rate deferral period that ended on December 31, 2007. The recovery of the second rate deferral occurred over a 21-month period that began April 1, 2008 and ended on December 31, 2009.

Financing Credits

Concurrent with the recovery of the deferred amounts related to the first rate deferral period, we are providing credits to residential customers to compensate them primarily for income tax benefits associated with the financing of the deferred amounts with rate stabilization bonds.

Senate Bill 1 Credits

As a result of Senate Bill 1, beginning January 1, 2007, we were required to provide to residential electric customers a credit equal to the amount collected from all BGE electric customers for the decommissioning of Calvert Cliffs and to suspend collection of the residential return component of the administrative charge collected through residential standard offer service rates through May 31, 2007. Under an order issued by the Maryland PSC in May 2007, as of June 1, 2007, we were required to reinstate collection of the residential return component of the administration charge in rates and to provide all residential electric customers a credit for the residential return component of the administrative charge. Under the 2008 Maryland settlement agreement, BGE was allowed to resume collection of the residential return portion of the administrative charge from June 1, 2008 through May 31, 2010 without having to rebate it to residential customers.

The decrease in revenues during the quarter and six months ended June 30, 2010 compared to the same period in 2009 is primarily due to the reinstatement of the credit for the residential return component of the administrative charge on June 1, 2010, partially offset by higher distribution volumes.

Electricity Purchased for Resale Expenses

Electricity purchased for resale expenses include the cost of electricity purchased for resale to our standard offer service customers. These costs do not include the cost of electricity purchased by delivery service only customers. The following table summarizes our regulated electricity purchased for resale expenses:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2010	**2009**	**2010**	**2009**
	(In millions)			
Actual costs	**$ 387.8**	$ 392.0	**$ 845.9**	$ 901.4
Recovery under rate stabilization plan	**13.6**	10.5	**29.1**	26.3
Electricity purchased for resale expenses	**$ 401.4**	$ 402.5	**$ 875.0**	$ 927.7

Actual Costs

BGE's actual costs for electricity purchased for resale decreased $4.2 million during the quarter ended June 30, 2010 compared to the same period of 2009, primarily due to lower contract prices to purchase electricity for our customers partially offset by higher volumes.

BGE's actual costs for electricity purchased for resale decreased $55.5 million during the six months ended June 30, 2010 compared to the same period of 2009, primarily due to lower contract prices to purchase electricity for our customers and lower volumes.

Recovery Under Rate Stabilization Plan

In late June 2007, we began recovering previously deferred amounts from customers. We recovered $13.6 million and $29.1 million during the quarter and six months ended June 30, 2010 in deferred electricity purchased for resale expenses. These collections secure the payment of principal and interest and other ongoing costs associated with rate stabilization bonds issued by a subsidiary of BGE in June 2007.

Electric Operations and Maintenance Expenses

Regulated operations and maintenance expenses increased $26.2 million in the six months ended June 30, 2010 compared to the same period in 2009, primarily due to increased distribution service restoration expenses of $18.5 million, $10.7 million of higher labor and benefit costs, and the impact of inflation on other costs of $5.0 million, partially offset by decreased uncollectible accounts receivable expense of $16.6 million.

Electric Depreciation and Amortization

Regulated electric depreciation and amortization expense decreased $5.4 million during the quarter ended June 30, 2010, compared to the same period in 2009, primarily due to decreased amortization of $7.2 million of deferred

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conservation costs due to a regulatory change in the deferral period associated with these costs, partially offset by a $1.5 million increase in property, plant and equipment depreciation.

Regulated electric depreciation and amortization expense decreased $4.5 million during the six months ended June 30, 2010, compared to the same period in 2009, primarily due to decreased amortization of $11.6 million of deferred conservation costs due to a regulatory change in the deferral period associated with these costs, partially offset by a $3.8 million increase in property, plant and equipment depreciation and increased amortization of $2.1 million of deferred costs associated with various demand response programs.

Regulated Gas Business

Our regulated gas business is discussed in detail in *Item 1. Business Gas Business* section of our 2009 Annual Report on Form 10-K.

Results

	Quarter Ended June 30,		Six Months Ended June 30,	
	2010	**2009**	**2010**	**2009**
		(In millions)		
Revenues	**$ 100.4**	$ 111.7	**$ 418.4**	$ 498.6
Gas purchased for resale expenses	**(42.1)**	(51.6)	**(236.6)**	(309.7)
Operations and maintenance expenses	**(39.1)**	(45.0)	**(74.3)**	(80.9)
Depreciation and amortization	**(11.0)**	(10.7)	**(22.3)**	(22.1)
Taxes other than income taxes	**(8.1)**	(8.5)	**(18.5)**	(18.9)
Income (Loss) from operations	**$ 0.1**	$ (4.1)	**$ 66.7**	$ 67.0
Net (Loss) Income	**$ (3.9)**	$ (6.2)	**$ 33.3**	$ 33.4
Net (Loss) Income attributable to common stock	**$ (4.7)**	$ (6.9)	**$ 31.8**	$ 31.9

Above amounts include intercompany transactions eliminated in our Consolidated Financial Statements. The Information by Operating Segment section within the Notes to Consolidated Financial Statements on page 15 provides a reconciliation of operating results by segment to our Consolidated Financial Statements.

Gas Revenues

The changes in gas revenues during the quarter and six months ended June 30, 2010 compared to the same periods of 2009 were caused by:

	Quarter Ended June 30, 2010 vs. 2009	Six Months Ended June 30, 2010 vs. 2009
	(In millions)	
Distribution volumes	$ (2.0)	$ (4.7)
Conservation surcharge	(0.2)	(0.6)
Gas revenue decoupling	1.8	4.4
Gas cost adjustments	(2.3)	(76.2)
Total change in gas revenues from gas system sales	(2.7)	(77.1)
Off-system sales	(9.1)	(4.9)
Other	0.5	1.8
Total change in gas revenues	$ (11.3)	$ (80.2)

Distribution Volumes

The percentage changes in our distribution volumes, by type of customer, during the quarter and six months ended June 30, 2010 compared to the same periods of 2009 were:

	Quarter Ended June 30, 2010 vs. 2009	Six Months Ended June 30, 2010 vs. 2009
Residential	(10.6)%	(3.2)%
Commercial	(16.5)	(12.0)
Industrial	8.7	13.5

During the quarter ended June 30, 2010 compared to the same period in 2009, we distributed less gas to residential customers, mostly due to warmer weather, partially offset by increased usage per customer and an increased number of customers. We distributed less gas to commercial customers compared to the same period of 2009, mostly due to decreased usage per customer and warmer weather. We distributed more gas to industrial customers mostly due to increased usage by customers and an increased number of customers.

During the six months ended June 30, 2010 compared to the same period in 2009, we distributed less gas to residential customers, mostly due to warmer weather, partially offset by increased usage per customer and an increased number of customers. We distributed less gas to commercial customers, mostly due to decreased usage per customer and warmer weather, partially offset by an increased number of customers. We distributed more gas to

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industrial customers, mostly due to increased usage per customer.

Conservation Surcharge

Beginning February 2009, the Maryland PSC approved a customer surcharge through which BGE recovers costs associated with certain programs designed to help BGE encourage customer conservation.

Gas Revenue Decoupling

The Maryland PSC allows us to record a monthly adjustment to our gas distribution revenues to eliminate the effect of abnormal weather and usage patterns per customer on our gas distribution volumes, thereby recovering a specified dollar amount of distribution revenues per customer, by customer class, regardless of changes in consumption levels. This means BGE recognizes revenues at Maryland PSC-approved levels per customer, regardless of what actual distribution volumes were for a billing period. Therefore, while these revenues are affected by customer growth, they will not be affected by actual weather or usage conditions. We then bill or credit impacted customers in subsequent months for the difference between approved revenue levels under revenue decoupling and actual customer billings.

Gas Cost Adjustments

We charge our gas customers for the natural gas they purchase from us using gas cost adjustment clauses set by the Maryland PSC as described in *Note 1* of our 2009 Annual Report on Form 10-K. However, under the market-based rates mechanism approved by the Maryland PSC, our actual cost of gas is compared to a market index (a measure of the market price of gas in a given period). The difference between our actual cost and the market index is shared equally between shareholders and customers.

Customers who do not purchase gas from BGE are not subject to the gas cost adjustment clauses because we are not selling gas to them. However, these customers are charged base rates to recover the costs BGE incurs to deliver their gas through our distribution system, and are included in the gas distribution volume revenues.

Gas cost adjustment revenues decreased $2.3 million during the quarter ended June 30, 2010, compared to the same period of 2009, mostly because we sold less gas, partially offset by higher rates.

Gas cost adjustment revenues decreased $76.2 million during the six months ended June 30, 2010, compared to the same period of 2009, because we sold less gas at lower rates.

Off-System Gas Sales

Off-system gas sales are low-margin direct sales of gas to wholesale suppliers of natural gas. Off-system gas sales, which occur after we have satisfied our customers' demand, are not subject to gas cost adjustments. The Maryland PSC approved an arrangement for part of the margin from off-system sales to benefit customers (through reduced costs) and the remainder to be retained by BGE (which benefits shareholders). Changes in off-system sales do not significantly impact earnings.

Revenues from off-system gas sales decreased during the quarter and six months ended June 30, 2010 compared to the same periods of 2009, primarily due to lower volumes, partially offset by higher prices.

Gas Purchased For Resale Expenses

Gas purchased for resale expenses include the cost of gas purchased for resale to our customers and for off-system sales. These costs do not include the cost of gas purchased by delivery service only customers.

Gas costs decreased $9.5 million during the quarter ended June 30, 2010 compared to the same period of 2009 because we purchased less gas, partially offset by higher prices.

Gas costs decreased $73.1 million during the six months ended June 30, 2010 compared to the same period of 2009 because we purchased less gas at lower prices.

Gas Operations and Maintenance Expenses

Regulated gas operation and maintenance expenses decreased $5.9 million in the quarter ended June 30, 2010 compared to the same period in 2009, primarily due to decreased uncollectible accounts receivable expense of $6.8 million, partially offset by $2.2 million of higher labor and benefit costs.

Regulated gas operation and maintenance expenses decreased $6.6 million during the six months ended June 30, 2010 compared to the same period in 2009, primarily due to decreased uncollectible accounts receivable expense of $12.5 million, partially offset by higher labor and benefit costs of $4.0 million, and the impact of inflation on other costs of $1.9 million.

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Holding Company and Other Nonregulated Businesses

Results

	Quarter Ended June 30,		Six Months Ended June 30,	
	2010	**2009**	**2010**	**2009**
		(In millions)		
Revenues	**$ 0.1**	$ 3.0	**$ 0.1**	$ 5.5
Operating expense	**13.4**	14.0	**29.1**	29.2
Impairment losses and other costs		(6.7)		(6.7)
Depreciation and amortization	**(12.2)**	(16.3)	**(26.1)**	(32.7)
Taxes other than income taxes	**(1.3)**	(1.1)	**(2.2)**	(1.9)
Net gain on divestitures	**0.1**		**0.1**	
Income (Loss) from Operations	**$ 0.1**	$ (7.1)	**$ 1.0**	$ (6.6)
Net Income (Loss)	**$ 0.7**	$ (3.6)	**$ (3.6)**	$ (3.5)
Net Income (Loss) attributable to common stock	**$ 0.7**	$ (3.7)	**$ (3.6)**	$ (3.6)
Other Items Included in Operations (after-tax):				
Deferred income tax expense relating to federal subsidies for providing post-employment prescription drug benefits	**$**	$	**$ (4.8)**	$
Impairment losses and other costs		(3.2)		(3.2)
Total Other Items	**$**	$ (3.2)	**$ (4.8)**	$ (3.2)

Above amounts include intercompany transactions eliminated in our Consolidated Financial Statements. The Information by Operating Segment section within the Notes to Consolidated Financial Statements on page 15 provides a reconciliation of operating results by segment to our Consolidated Financial Statements.

Net income attributable to common stock for the quarter ended June 30, 2010 exceeded net loss attributable to common stock for the same period in 2009 by $4.4 million primarily due to the absence in 2010 of an impairment loss as a result of a write-off in 2009 of an uncollectible advance to an affiliate of $3.2 million after-tax.

Consolidated Nonoperating Income and Expenses

Other Expenses

Other expenses decreased $40.1 million during the six months ended June 30, 2010 compared to the same period of 2009 mostly due to the absence in 2010 of $62.4 million of other-than-temporary impairment charges related to nuclear decommissioning trust fund assets recorded in 2009.

Fixed Charges

Our fixed charges decreased during the quarter and six months ended June 30, 2010 compared to the same periods of 2009 primarily due to lower level of interest expense due to repayments of debt made in 2009. For the six months ended June 30, 2010, the decrease was partially offset by a $50.1 million loss recognized in February 2010 on the retirement of $486.5 million of our 7.00% Notes due April 1, 2012. We discuss this transaction in the *Notes to Consolidated Financial Statements* on page 17.

Fixed charges at BGE decreased during the six months ended June 30, 2010 compared to the same period of 2009 primarily due to lower level of interest expense due to repayments of debt made in 2009.

Income Taxes

Income tax expense decreased $65.3 million during the quarter ended June 30, 2010 compared to the same period of 2009 mostly due to a higher effective tax rate in 2009. The higher effective tax rate for 2009 reflected the impact of unfavorable nondeductible adjustments (primarily related to nondeductible dividends on Series B preferred stock and the write-off of the unamortized debt discount on senior notes) in relation to the lower estimated 2009 taxable income (primarily attributable to losses on the divestiture of a majority of our international commodities and our Houston-based gas trading operations).

In the six months ended June 30, 2010, we had income tax expense of $133.1 million and, in the same period of 2009, we had income tax benefits of $139.4 million. The $272.5 million change is primarily due to higher income before income taxes in 2010 compared to a loss before income taxes in 2009. Additionally, a higher effective tax rate in 2009 decreased income tax expense because it produced a higher income tax benefit when applied to the loss before income taxes.

BGE's income tax expense decreased $8.2 million during the six months ended June 30, 2010 compared to the same period of 2009 mostly due to a decrease in income before income taxes.

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Financial Condition

Cash Flows

The following table summarizes our cash flows for the six months ended June 30, 2010 and 2009.

	2010 Segment Cash Flows Six Months Ended June 30, 2010				Consolidated Cash Flows Six Months Ended June 30,	
	Generation	NewEnergy	Regulated	Eliminations, Holding Company and Other	2010	2009
	(In millions)					
Operating Activities						
Net income (loss)	$ 42.4	$ 154.9	$ 81.4	$ (3.6)	$ 275.1	$ (91.4)
Non-cash merger termination and strategic alternatives costs						37.2
Derivative contracts classified as financing activities[1]		79.8			79.8	785.3
Other non-cash adjustments to net income (loss)	250.6	(108.8)	223.5	30.9	396.2	948.6
Changes in working capital						
Derivative assets and liabilities, excluding collateral	(1.9)	229.9	(0.7)		227.3	185.2
Net collateral and margin		(76.0)	2.6		(73.4)	1,094.9
Accrued taxes	(1,129.1)	356.6	(43.4)	(10.3)	(826.2)	(7.1)
Other changes	(144.3)	(3.8)	(47.9)	(44.9)	(240.9)	224.6
Defined benefit obligations[2]					(5.3)	(263.9)
Other	41.6	(93.4)	(40.6)	53.2	(39.2)	51.0
Net cash (used in) provided by operating activities	(940.7)	539.2	174.9	25.3	(206.6)	2,964.4
Investing activities						
Investments in property, plant and equipment	(180.1)	(49.0)	(190.3)	(5.6)	(425.0)	(809.1)
Asset and business acquisitions, net of cash acquired	(372.9)				(372.9)	
Change in cash pool[3]	1,107.3	(336.6)	314.7	(1,085.4)		
Contributions to nuclear decommissioning trust funds						(18.7)
Proceeds from sale of investments and other assets		0.1		21.1	21.2	80.9
Proceeds from investment tax credits and grants related to renewable energy investments	17.5	4.0			21.5	
Contract and portfolio acquisitions	(1.0)	(28.0)			(29.0)	(2,153.7)
(Increase) decrease in restricted funds		(31.3)	0.8	0.5	(30.0)	1,004.4
Other investments	(1.4)	0.9		(0.2)	(0.7)	(1.8)
Net cash used in investing activities	569.4	(439.9)	125.2	(1,069.6)	(814.9)	(1,898.0)
Cash flows from operating activities plus cash flows from investing activities	$ (371.3)	$ 99.3	$ 300.1	$ (1,044.3)	(1,021.5)	1,066.4
Financing Activities[2]						

Net repayment of debt	(646.0)	(1,587.1)
Proceeds from issuance of common stock	8.8	13.6
Debt issuance costs	(0.7)	(62.8)
Common stock dividends paid	(92.6)	(133.7)
BGE preference stock dividends paid	(6.6)	(6.6)
Proceeds from contract and portfolio acquisitions	2.3	2,243.1
Derivative contracts classified as financing activities[1]	(79.8)	(785.3)
Other	(0.7)	11.8
Net cash used in financing activities	(815.3)	(307.0)
Net (decrease) increase in cash and cash equivalents	$ (1,836.8)	$ 759.4

1 All ongoing cash flows from derivative contracts deemed to contain a financing element at inception must be reclassified from operating activities to financing activities.

2 Items are not allocated to the business segments because they are managed for the company as a whole.

3 As part of the ring-fencing measures required by the Maryland PSC in its 2009 order approving the transaction with EDF, BGE ceased participation in the cash pool on January 7, 2010. We discuss this ring-fencing measure in Notes to Consolidated Financial Statements.

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Cash Flows from Operating Activities

In the six months ended June 30, 2010, cash used in operating activities was $0.2 billion, primarily driven by $0.2 billion of cash inflows from our regulated business and $0.4 billion of cash inflows from our competitive businesses, offset by $0.8 billion in income tax payments in our competitive businesses, most of which related to the federal taxes associated with the EDF transaction, which closed in the fourth quarter of 2009.

In the six months ended June 30, 2009, the company generated $3.0 billion in cash from operating activities, primarily due to:

- $1.5 billion in working capital including $1.1 billion for net collateral and margin and $0.3 billion for materials, supplies, and fuel stocks, and
- $0.8 billion of derivative contracts deemed to contain a financing element at inception that must be classified as financing activities rather than operating activities related to the divestiture of our Houston-based gas trading business.

Partially offsetting these cash inflows was $0.3 billion of contributions to our defined benefit pension plans.

The $3.2 billion decrease in operating cash flows for the six months ended June 30, 2010 compared to the same period of 2009 is primarily due to:

- $1.0 billion higher income taxes paid,
- $0.1 billion of lower operating cash flows from our regulated businesses, primarily due to the residential customer rate credit in the first quarter of 2010 and higher distribution service restoration expenses associated with 2010 storms,
- $0.7 billion lower derivative contract settlements reclassified as financing activities in 2010, and
- $1.2 billion lower net collateral and margin returned in 2010 as compared to 2009 as follows:

	June 30,	
	2010	**2009**
	(In millions)	
Net collateral and margin held (posted), January 1,	**$ 77.2**	$ (1,445.6)
Return of collateral held associated with nonderivative contracts	**(9.2)**	(5.4)
Net return of collateral posted associated with nonderivative contracts	**2.9**	320.9
Return of initial and variation margin posted on exchange-traded transactions recorded in accounts receivable	**0.9**	407.7
Additional fair value net cash collateral (posted) held (netted against derivative assets / liabilities)*	**(68.0)**	371.7
Change in net collateral and margin (posted) held	**(73.4)**	1,094.9
Net collateral and margin held (posted), June 30,	**$ 3.8**	$ (350.7)

** We discuss our netting of fair value collateral with our derivative assets / liabilities in more detail in Note 13 to Consolidated Financial Statements of our 2009 Annual Report on Form 10-K.*

We discuss all forms of collateral in terms of their impact on our business in the *Collateral* section.

Partially offsetting these decreases in operating cash flows was $0.3 billion of lower contributions to our defined benefit pension plans.

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Cash Flows from Investing Activities

Cash used in investing activities for the six months ended June 30, 2010 was $0.8 billion, compared to $1.9 billion used in the six months ended June 30, 2009. The $1.1 billion decrease from the prior year was due to:

- $2.1 billion lower outflows associated with contract and portfolio acquisitions as a result of the structure of the divestiture of a majority of our international commodities operation in March 2009, and
- $0.4 billion of lower investments in property, plant, and equipment, primarily related to environmental additions at our Brandon Shores coal-fired generating plant that went into service in the fourth quarter of 2009 and the absence of nuclear capital spending in 2010 due to the deconsolidation of CENG in 2009.

These decreases were offset by:

- $1.0 billion of lower restricted funds activity in 2010. In January 2009, our restricted funds decreased by $1.0 billion, primarily due to the release of restricted funds for the repayment of $1 billion of 14% Senior Notes to MidAmerican.
- $0.4 billion increase in cash used for asset and business acquisitions. We discuss our acquisitions in the *Notes to Consolidated Financial Statements*.

Cash Flows from Financing Activities

Cash used in financing activities was $0.8 billion in the six months ended June 30, 2010, compared to cash used in financing activities of $0.3 billion in the six months ended June 30, 2009. The $0.5 billion increase in cash used in financing activities was primarily due to $2.2 billion of lower proceeds from contract and portfolio acquisitions related to the structure of the divestiture of the majority of our international commodities operation in March 2009, partially offset by the following:

- $0.7 billion lower cash outflows associated with derivative contracts deemed to contain a financing element at inception that must be classified as financing activities rather than operating activities in the six months ended June 30, 2010 compared to the same period in 2009. These contracts primarily related to transactions associated with the divestiture of our Houston-based gas trading operation. During March 2009, we executed transactions at prices that differed from market prices. As a result, for cash flows associated with the out-of-the money derivative transactions executed, we recorded the ongoing cash flows related to these contracts as financing cash flows in March 2009, and
- $0.9 billion lower net debt repayments in the six months ended June 30, 2010 compared to the same period in 2009. In the six months ended June 30, 2009, we repaid $1.0 billion of 14% Senior Notes and $0.5 billion in short term borrowings on our credit facilities. In the six months ended June 30, 2010, we retired $0.5 billion 7.00% Notes due April 1, 2012 pursuant to a cash tender offer and repurchased outstanding tax exempt notes totaling $0.1 billion.

Available Sources of Funding

In addition to cash generated from operations, we rely upon access to capital for our capital expenditure programs and for the liquidity required to operate and support our commercial businesses. Our liquidity requirements are funded by credit facilities and cash. We fund our short-term working capital needs with existing cash and with our credit facilities, many of which support direct cash borrowings and the issuance of commercial paper. We also use our credit facilities to support the issuance of letters of credit, primarily for our NewEnergy business.

The primary drivers of our use of liquidity have been our capital expenditure requirements and collateral requirements associated with hedging our generating assets and hedging our NewEnergy business in both power and gas. In order to reduce these collateral requirements, we have modified the structure of certain transactions, terminated others, and entered into new contracts that either do not have a collateral requirement or allow the posting of alternative forms of collateral. Significant changes in the prices of commodities, depending on hedging strategies we have employed, could require us to post additional letters of credit, thereby reducing the overall amount available under our credit facilities, or to post additional cash, thereby reducing our available cash balance. Additional regulation of the derivatives markets could also require us to post additional cash collateral. We discuss the recently enacted financial reform legislation in more detail on page 40.

We discuss our, and BGE's, credit facilities in detail beginning on page 16 of the *Notes to the Consolidated Financial Statements*.

Net Available Liquidity

Constellation Energy's and BGE's net available liquidity at June 30, 2010 was $5.2 billion and $0.9 billion, respectively. We discuss net available liquidity in more detail in the *Notes to Consolidated Financial Statements* on page 17.

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Collateral

Constellation Energy's collateral requirements generally arise from the needs of its NewEnergy business as a result of its participation in certain organized markets, such as Independent System Operators (ISOs) or financial exchanges, as well as from its margining on over-the-counter (OTC) contracts.

To support NewEnergy's wholesale and retail power obligations and our limited trading activities, Constellation Energy posts collateral to ISOs. Forward hedging of our Generation and NewEnergy businesses creates the need to transact with exchanges such as New York Mercantile Exchange and Intercontinental Exchange. We post initial margin based on exchange rules, as well as variation margin related to the change in value of the net open position with the exchange.

In addition to the collateral posted to ISOs and exchanges, we post collateral with certain OTC counterparties. These collateral amounts may be fixed or may vary with price levels.

There are certain inherent asymmetries relating to the use of collateral that create liquidity requirements for our Generation and NewEnergy businesses. These asymmetries arise from our actions to be economically hedged, as well as market conditions or conventions for conducting business that result in some transactions being collateralized while others are not, including:

In our NewEnergy business, we generally do not receive collateral under contractual obligations to supply power or gas to our customers but we hedge these transactions through purchases of power and gas that generally require us to post collateral. By entering into a gas supply agreement with the buyer of our gas trading operation, we have reduced our collateral requirements to support our retail gas operation. We also intend to further align our load obligations by buying generation assets in regions where we do not have a significant generation presence and entering into longer-tenor agreements with merchant generators, further reducing our dependence on exchange-traded products, thereby lowering our collateral requirements.

In our Generation business, we may have to post collateral on our power sale or fuel purchase contracts.

Finally, collateral types may asymmetrically impact our liquidity. In margining with OTC counterparties, we may post letter of credit (LC) collateral for an out-of-the money counterparty. However, we may receive LC collateral when we are in-the-money with a counterparty. Posting LCs reduces our liquidity while the receipt of LC collateral does not increase our liquidity.

Customers of our NewEnergy business rely on the creditworthiness of Constellation Energy. In this regard, we have certain agreements that contain provisions that would require us to post additional collateral upon a credit rating downgrade in the senior unsecured debt of Constellation Energy. Based on contractual provisions at June 30, 2010, we estimate that if Constellation Energy's senior unsecured debt were downgraded to one level below the investment grade threshold we would have the following additional collateral obligations:

Credit Ratings Downgraded to[1]	Level Below Current Rating	Additional Obligations[2]
	(In billions)	
Below investment grade	1	$ 1.2

1 If there are split ratings among the independent credit-rating agencies, the lowest credit rating is used to determine our incremental collateral obligations.

2 Includes $0.2 billion related to derivative contracts as discussed in Notes to Consolidated Financial Statements beginning on page 32.

Based on market conditions and contractual obligations at the time of a downgrade, we could be required to post additional collateral in an amount that could exceed the obligation amounts specified above, which could be material. We discuss our credit facilities in the *Notes to Consolidated Financial Statements* beginning on page 16.

Capital Resources

Our estimated annual cash requirement amounts for the years 2010 and 2011 are shown in the table below.

We will continue to have cash requirements for:

- working capital needs,
- payments of interest, distributions, and dividends,
- capital expenditures, and
- the retirement of debt.

Capital requirements for 2010, 2011, and 2012 include estimates of spending for existing and anticipated projects. We continuously review and modify those estimates. Actual requirements may vary from the estimates included in the table below because of a number of factors including:

- regulation, legislation, and competition,
- BGE load requirements,
- environmental protection standards,
- the type and number of projects selected for construction or acquisition,
- the effect of market conditions on those projects,

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- the cost and availability of capital,
- potential capital contributions to CENG and UNE,
- the availability of cash from operations, and
- business decisions to invest in capital projects.

Our estimates are also subject to additional factors.

Please see the *Forward Looking Statements* section on page 69 and *Risk Factors* section in our 2009 Annual Report on Form 10-K. We discuss the potential impact of environmental legislation and regulation in more detail in *Business Environment* section beginning on page 39 and *Item 1. Business Environmental Matters* section of our 2009 Annual Report on Form 10-K.

Calendar Year Estimates	**2010**	**2011**
	(In billions)	
Generation and Other Capital Requirements:		
Major Environmental	$ 0.1	$
Maintenance	0.1	0.1
Growth	0.1	
Total Generation and Other Capital Requirements	0.3	0.1
NewEnergy Capital Requirements:		
Maintenance	0.1	0.1
Growth	0.1	0.1
Total NewEnergy Capital Requirements	0.2	0.2
Regulated Capital Requirements:		
Electric/Gas Distribution	0.4	0.4
Electric Transmission	0.1	0.1
Smart Energy Savers^{SM} Initiatives	0.1	0.2
Total Regulated Capital Requirements	0.6	0.7
Total Capital Requirements	$ 1.1	$ 1.0

Eligible capital projects are shown net of anticipated investment tax credits or grants.

As of the date of this report, we estimate our 2012 capital requirements will be approximately $0.9 billion.

Capital Requirements

Generation and NewEnergy Businesses

Our Generation and NewEnergy businesses' capital requirements consist of its continuing requirements, including expenditures for:

- maintenance and growth to generating plants,
- costs of complying with the Environmental Protection Agency (EPA), Maryland, and Pennsylvania environmental regulations and legislation, and

enhancements to our information technology infrastructure.

Regulated Electric and Gas

Regulated electric and gas construction expenditures primarily include new business construction needs and improvements to existing facilities, including projects to improve reliability and support demand response and conservation initiatives.

In July 2009, BGE filed with the Maryland PSC a proposal for a comprehensive smart grid initiative. The proposal includes the planned installation of 2 million residential and commercial electric and gas smart meters. We expect the total cost of the program to be approximately $480 million. The United States Department of Energy (DOE) selected BGE as a recipient of $200 million in federal funding for our smart grid initiative. This grant allows BGE to be reimbursed for smart grid expenditures up to $200 million, substantially reducing the total cost of this initiative. In June 2010, the Maryland PSC issued an order rejecting BGE's proposal as originally filed, but invited BGE to resubmit its request addressing the Maryland PSC's concerns. In July 2010, BGE filed an application for a rehearing of an amended smart grid initiative proposal which addressed the various issues raised in the Maryland PSC's June order. The PSC has agreed to an expedited hearing schedule and is expected to issue an order during the third quarter of 2010. The DOE has stated that a delay in the Maryland PSC's approval beyond mid-August 2010 could result in the grant being redirected to another applicant. We cannot predict the outcome of the DOE's decision, the Maryland PSC proceedings or the possible effect on our, or BGE's, financial results at this time.

Funding for Capital Requirements

We discuss our funding for capital requirements in our 2009 Annual Report on Form 10-K.

Contractual Payment Obligations and Committed Amounts

We enter into various agreements that result in contractual payment obligations in connection with our business activities. These obligations primarily relate to our financing arrangements (such as long-term debt, preference stock, and operating leases), purchases of capacity and energy to support the growth in our nonregulated business activities, and purchases of fuel and transportation to satisfy the fuel requirements of our power generating facilities.

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We detail our contractual payment obligations at June 30, 2010 in the following table:

	Payments				
	2010	2011-2012	2013-2014	There-after	Total
	(In millions)				
Contractual Payment Obligations					
Long-term debt:[1]					
Nonregulated					
Principal	$	$ 256.3	$ 20.0	$ 1,803.6	$ 2,079.9
Interest	58.7	236.6	231.8	2,765.6	3,292.7
Total	58.7	492.9	251.8	4,569.2	5,372.6
BGE					
Principal	28.4	254.2	537.0	1,352.4	2,172.0
Interest	64.9	247.2	194.9	1,253.4	1,760.4
Total	93.3	501.4	731.9	2,605.8	3,932.4
BGE preference stock				190.0	190.0
Operating leases[2]					
Operating leases, gross	123.3	396.5	331.8	335.9	1,187.5
Sublease rentals	(33.0)	(100.8)	(55.1)	(112.7)	(301.6)
Operating leases, net	90.3	295.7	276.7	223.2	885.9
Purchase obligations:[3]					
Purchased capacity and energy[4]	112.9	541.7	127.4	328.3	1,110.3
Purchased energy from CENG	271.5	1,383.0	2,028.9		3,683.4
Fuel and transportation	331.5	564.4	232.7	221.7	1,350.3
Other	76.7	71.2	13.4	6.7	168.0
Other noncurrent liabilities:					
Uncertain tax positions liability		143.8	67.7	18.3	229.8
Pension benefits[5]	26.1	217.5	203.7		447.3
Postretirement and postemployment benefits[6]	17.8	72.9	82.8	199.1	372.6
Total contractual payment obligations	$ 1,078.8	$ 4,284.5	$ 4,017.0	$ 8,362.3	$ 17,742.6

1 Amounts in long-term debt reflect the original maturity date. Investors may require us to repay $95.0 million early through remarketing features. Interest on variable rate debt is included based on the forward curve for interest rates.

2 Our operating lease commitments include future payment obligations under certain power purchase agreements as discussed further in Note 11 of our 2009 Annual Report on Form 10-K.

3 Contracts to purchase goods or services that specify all significant terms. Amounts related to certain purchase obligations are based on future purchase expectations, which may differ from actual purchases.

4 Our contractual obligations for purchased capacity and energy are shown on a gross basis for certain transactions, including both the fixed payment portions of tolling contracts and estimated variable payments under unit-contingent power purchase agreements.

5 Amounts related to pension benefits reflect our current 5-year forecast of contributions for our qualified pension plans and participant payments for our nonqualified pension plans. Refer to Note 7 of our 2009 Annual Report on Form 10-K for more detail on our pension plans.

6 Amounts related to postretirement and postemployment benefits are for unfunded plans and reflect present value amounts consistent with the determination of the related liabilities recorded in our Consolidated Balance Sheets.

Off-Balance Sheet Arrangements

We discuss our off-balance sheet arrangements in our 2009 Annual Report on Form 10-K.

At June 30, 2010, Constellation Energy had a total face amount of $9.7 billion in guarantees outstanding, of which $8.6 billion related to our Generation and NewEnergy businesses. These amounts do not represent incremental consolidated Constellation Energy obligations; rather, they primarily represent parental guarantees of certain subsidiary obligations to third parties in order to allow our subsidiaries 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 $2 billion at June 30, 2010, which represents the total amount the parent company could be required to fund based on June 30, 2010 market prices. For those guarantees related to our derivative liabilities, the fair value of the obligation is recorded in our Consolidated Balance Sheets. We believe it is unlikely that we would be required to perform or incur any losses associated with guarantees of our subsidiaries' obligations.

We discuss our other guarantees in the *Notes to Consolidated Financial Statements* beginning on page 19.

Risk Management

Market Risk

Economic Value at Risk (EVaR)

EVaR measures the potential pre-tax loss in the fair value of the Generation and NewEnergy businesses due to changes in market risk factors. EVaR is a one-day value-at-risk measure calculated at a 95% confidence level assuming a standard normal distribution of prices over the most recent rolling 3-month period. EVaR includes all positions over a forward rolling 60-month time horizon that expose us to market price risk, regardless of accounting treatment and business line.

Positions included in EVaR are comprised of all positions, regardless of accounting treatment, that create market risk including:

- derivative and nonderivative commodity contracts associated with our Generation and NewEnergy businesses,
- physical assets, such as our owned and contractually-controlled generating plants, and
- our share of investments in generating plants.

We include the positions related to physical assets to provide a more complete presentation of our commodity market risk exposures. EVaR includes illiquid products and positions for which there is limited price discovery. Modeling the positions in our Generation and NewEnergy businesses involves a number of assumptions, and includes

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projections of generation, emission rates and costs, customer load growth, load response to weather, and customer response to competitive supply. Changes in our forecast or management estimates will affect the fair value of these positions in a manner not captured by EVaR.

EVaR reflects the risk of loss due to market prices under normal market conditions. An inherent limitation of our value-at-risk measures is the reliance on historical prices. A sudden shift in market conditions can cause the future behavior of market prices to differ materially from the past. We use stress tests and scenario analysis to better understand extreme events as a complement to EVaR. This includes exposure to unlikely but plausible events in abnormal markets, sensitivity to changes in management projections of customer demand or forecasted generation output, and price sensitivity to illiquid points and regional basis spreads.

EVaR is monitored daily and is subject to regional and overall guidelines for the NewEnergy business. We place guidelines on the risk associated with illiquid delivery locations and regional basis within our NewEnergy business. Additionally, we monitor generation plant hedge ratios relative to guidelines specified by management. Stress tests and scenario analysis are conducted regularly and the results, trends, and explanations are reviewed by senior management and risk committees.

The EVaR amounts below represent the potential pre-tax change in the fair values of our Generation and NewEnergy businesses positions over a one-day holding period.

EVaR	**Quarter Ended June 30, 2010**
	(In millions)
95% Confidence Level, One-Day Holding Period	
Quarter end	$ 57.2
Average	54.8
High	63.3
Low	43.5

Value at Risk (VaR)

VaR measures the potential pre-tax loss in the fair value of the mark-to-market energy contracts due to changes in market risk factors. VaR is calculated assuming a standard normal distribution of prices over the most recent rolling 3-month period. VaR includes all positions subject to mark-to-market accounting, including contracts that hedge the economics of NewEnergy nonderivative power and fuel contracts, which do not receive hedge accounting treatment, and contracts designated for trading. Thus, the positions for which we monitor VaR are included within, and are not incremental, to the positions subject to EVaR.

VaR and EVaR have similar limitations. VaR may include some products and positions for which there is limited price discovery or market depth. The modeling of option positions included in VaR involves a number of assumptions and approximations. An inherent limitation of our VaR measures is the reliance on historical prices. A sudden shift in market conditions can cause the future behavior of market prices to differ materially from that of the past.

The VaR amounts below represent the potential pre-tax loss in the fair value of our Generation and NewEnergy businesses positions subject to mark-to-market accounting, including both trading and non-trading activities, over one and ten-day holding periods.

Total Mark-to-Market VaR	**Quarter Ended June 30, 2010**
	(In millions)
99% Confidence Level, One-Day Holding Period	
Quarter end	$ 7.2
Average	6.2
High	10.0
Low	4.8
95% Confidence Level, One-Day Holding Period	
Quarter end	5.5
Average	4.7

High	7.6
Low	3.6
95% Confidence Level, Ten-Day Holding Period	
Quarter end	17.3
Average	15.0
High	24.1
Low	11.5

Wholesale Credit Risk

We measure wholesale credit risk as the replacement cost for open energy commodity and derivative transactions (both mark-to-market and accrual) adjusted for amounts owed to or due from counterparties for settled transactions. The replacement cost of open positions represents unrealized gains, net of any unrealized losses, where we have a legally enforceable right of setoff. We monitor and manage our credit risk through credit policies and procedures, which include an established credit approval process, daily monitoring of counterparty credit limits, the use of credit mitigation measures such as margin, collateral, or prepayment arrangements, and the use of master netting agreements.

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As of June 30, 2010 and December 31, 2009, counterparties in our credit portfolio had the following public credit ratings:

	June 30, 2010	December 31, 2009
Rating		
Investment Grade[1]	**45%**	43%
Non-Investment Grade	**2**	2
Not Rated	**53**	55

1 Includes counterparties with an investment grade rating by at least one of the major credit rating agencies. If split rating exists, the lower rating is used.

Our exposure to "Not Rated" counterparties was $1.4 billion at June 30, 2010 compared to $1.5 billion at December 31, 2009. This decrease was mostly driven by a reduction in our CENG credit concentration exposure, which is not externally rated and a decrease in our portfolio's credit exposure to unrated natural gas customers, international coal customers, and freight customers that do not have public credit ratings as a result of the divestiture of these operations in 2009.

Many of our not rated counterparties (including CENG) are considered investment grade equivalent based on our internal credit ratings. We utilize internal credit ratings to evaluate the creditworthiness of our wholesale customers, including those companies that do not have public credit ratings. Based on internal credit ratings, approximately $1.2 billion or 83% of the exposure to not rated counterparties was rated investment grade equivalent at June 30, 2010 and approximately $1.2 billion or 81% was rated investment grade equivalent at December 31, 2009.

The following table provides the breakdown of the credit quality of our wholesale credit portfolio based on our internal credit ratings:

	June 30, 2010	December 31, 2009
Investment Grade Equivalent	**89%**	88%
Non-Investment Grade	**11**	12

Our total exposure, net of collateral, to counterparties across our entire wholesale portfolio is $2.7 billion as of June 30, 2010. The top ten counterparties account for approximately 54% of our total exposure with approximately 4% of that exposure being non-investment grade.

If a counterparty were to default on its contractual obligations and we were to liquidate transactions with that entity, our potential credit loss would include all forward and settlement exposure plus any additional costs related to termination and replacement of the positions. This would include contracts accounted for using the mark-to-market, hedge, and accrual accounting methods, the amount owed or due from settled transactions, less any collateral held from the counterparty. In addition, if a counterparty were to default under an accrual contract that is currently favorable to us, we may recognize a material adverse impact on our results in the future delivery period to the extent that we are required to replace the contract that is in default with another contract at current market prices. To reduce our credit risk with counterparties, we attempt to enter into agreements that allow us to obtain collateral on a contingent basis, seek third-party guarantees of the counterparty's obligation, and enter into netting agreements that allow us to offset receivables and payables with forward exposure across many transactions.

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 June 30, 2010, two counterparties, CENG and a large power cooperative, comprise exposure concentrations of 17% and 11%, respectively. 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.

Due to volatility in the prices of energy commodities and derivatives, the market value of contractual positions with individual counterparties could exceed established credit limits or collateral provided by those counterparties. If such a counterparty were then to fail to perform its obligations under its contract (for example, fail to deliver the power we had contracted for), we could incur a loss that could have a material impact on our financial results.

If a counterparty were to default and we were to liquidate all contracts with that entity, our credit loss would include the loss in value of derivative contracts recorded at fair value, the amount owed for settled transactions, and additional payments, if any, that we would have to make to settle unrealized losses on accrual contracts. In addition, if a counterparty were to default under an accrual contract that is currently favorable to us, we may recognize a material adverse impact in our results in the future delivery period to the extent that we are required to replace the contract that is in default with another contract at current market prices. These potential losses would be limited to the extent that the

in-the-money amount exceeded any credit mitigants such as cash, letters of credit, or parental guarantees supporting the counterparty obligation.

We also enter into various wholesale transactions through ISOs. These ISOs are exposed to counterparty credit risks. Any losses relating to counterparty defaults impacting the ISOs are allocated to and borne by all other market participants in the ISO. These ISOs have established credit policies and practices to mitigate the exposure of counterparty credit risks. As a market participant, we continuously assess our exposure to the credit risks of each ISO.

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BGE is exposed to wholesale credit risk of its suppliers for electricity and gas to serve its retail customers. BGE may receive performance assurance collateral to mitigate electricity suppliers' credit risks in certain circumstances. Performance assurance collateral is designed to protect BGE's potential exposure over the term of the supply contracts and will fluctuate to reflect changes in market prices. In addition to the collateral provisions, there are supplier "step-up" provisions, where other suppliers can step in if the early termination of a full-requirements service agreement with a supplier should occur, as well as specific mechanisms for BGE to otherwise replace defaulted supplier contracts. All costs incurred by BGE to replace the supply contract are to be recovered from the defaulting supplier or from customers through rates.

Interest Rate Risk, Retail Credit Risk, Foreign Currency Risk, Security Price Risk, and Operational Risk

We discuss our exposure to interest rate risk, retail credit risk, foreign currency risk, security price risk and operational risk in the *Risk Management* section of our 2009 Annual Report on Form 10-K.

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Item 3. Quantitative and Qualitative Disclosures About Market Risk

We discuss the following information related to our market risk:

- hedging activities in the *Notes to Consolidated Financial Statements* beginning on page 23,
- activities of our Generation and NewEnergy businesses in their respective section of *Management's Discussion and Analysis* beginning on page 43,
- evaluation of commodity and credit risk in the *Risk Management* section of *Management's Discussion and Analysis* beginning on page 63, and
- changes to our business environment in the *Business Environment* section of *Management's Discussion and Analysis* beginning on page 39.

Items 4 and 4(T). Controls and Procedures

A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within Constellation Energy or BGE have been detected. These inherent limitations include errors by personnel in executing controls due to faulty judgment or simple mistakes, which could occur in situations such as when personnel performing controls are new to a job function or when inadequate resources are applied to a process. Additionally, controls can be circumvented by the individual acts of some persons or by collusion of two or more people.

The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no absolute assurance that any design will succeed in achieving its stated goals under all potential future conditions; over time, controls may become inadequate because of changes in conditions or personnel, or the degree of compliance with the policies or procedures may deteriorate. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected.

Evaluation of Disclosure Controls and Procedures

The principal executive officer and principal financial officer of Constellation Energy have each evaluated the effectiveness of the disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")) as of the end of the fiscal quarter covered by this quarterly report (the "Evaluation Date"). Based on such evaluation, such officers have concluded that, as of the Evaluation Date, Constellation Energy's disclosure controls and procedures are effective in providing reasonable assurance that information required to be disclosed in the reports that Constellation Energy files and submits under the Exchange Act is recorded, processed, summarized, and reported when required and is accumulated and communicated to management, as appropriate, to allow timely decisions regarding required disclosure.

The principal executive officer and principal financial officer of BGE have each evaluated the effectiveness of the disclosure controls and procedures as of the Evaluation Date. Based on such evaluation, such officers have concluded that, as of the Evaluation Date, BGE's disclosure controls and procedures are effective in providing reasonable assurance that information required to be disclosed in the reports that BGE files and submits under the Exchange Act is recorded, processed, summarized, and reported when required and is accumulated and communicated to management, as appropriate, to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

During the quarter ended June 30, 2010, there has been no change in either Constellation Energy's or BGE's internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) that has materially affected, or is reasonably likely to materially affect, either Constellation Energy's or BGE's internal control over financial reporting.

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PART II. OTHER INFORMATION

Item 1. Legal Proceedings

We discuss our Legal Proceedings in the *Notes to Consolidated Financial Statements* beginning on page 20.

Item 2. Issuer Purchases of Equity Securities

The following table discloses purchases of shares of our common stock made by us or on our behalf for the periods shown below.

Period	Total Number of Shares Purchased[1]	Average Price Paid for Shares	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Dollar Amounts of Shares that May Yet Be Purchased Under the Plans and Programs (at month end)
April 1 April 30, 2010	3,539	$ 35.43		
May 1 May 31, 2010	121	38.50		
June 1 June 30, 2010	2,817	34.31		
Total	6,477	$ 35.00		

1 Represents shares surrendered by employees to satisfy tax withholding obligations on vested restricted stock and restricted stock units.

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Item 5. Other Information

Forward Looking Statements

We make statements in this report that are considered forward looking statements within the meaning of the Securities Exchange Act of 1934. Sometimes these statements will contain words such as "believes," "anticipates," "expects," "intends," "plans," and other similar words. We also disclose non-historical information that represents management's expectations, which are based on numerous assumptions. These statements and projections are not guarantees of our future performance and are subject to risks, uncertainties, and other important factors that could cause our actual performance or achievements to be materially different from those we project. These risks, uncertainties, and factors include, but are not limited to:

- the timing and extent of changes in commodity prices and volatilities for energy and energy-related products including coal, natural gas, oil, electricity, nuclear fuel, and emission allowances, and the impact of such changes on our liquidity requirements,

- the liquidity and competitiveness of wholesale and retail markets for energy commodities,

- the conditions of the capital markets, interest rates, foreign exchange rates, availability of credit facilities to support business requirements, liquidity, and general economic conditions, as well as Constellation Energy Group's (Constellation Energy) and Baltimore Gas and Electric's (BGE) ability to maintain their current credit ratings,

- the effectiveness of Constellation Energy's and BGE's risk management policies and procedures and the ability and willingness of our counterparties to satisfy their financial and performance commitments,

- losses on the sale or write-down of assets due to impairment events or changes in management intent with regard to either holding or selling certain assets,

- the ability to successfully identify, finance, and complete acquisitions and sales of businesses and assets, including generating facilities and new nuclear generation development projects,

- the effect of weather and general economic and business conditions on energy supply, demand, prices, and customers' and counterparties' ability to perform their obligations or make payments,

- the ability to attract and retain customers in our NewEnergy business and to adequately forecast their energy usage,

- the timing and extent of deregulation of, and competition in, the energy markets, and the rules and regulations adopted in those markets,

- regulatory or legislative developments federally, in Maryland, or in other states that affect energy deregulation, the price of energy, transmission or distribution rates and revenues, demand for energy, or increases in costs, including costs related to safety, or environmental compliance,

- the ability of our regulated and nonregulated businesses to comply with complex and/or changing market rules and regulations,

- the ability of BGE to recover all its costs associated with providing customers service,

- operational factors affecting our generating facilities, BGE's transmission and distribution facilities, or our other commercial operations, including weather-related damages, unscheduled outages or repairs, unanticipated changes in fuel costs or availability, unavailability of coal or gas transportation or electric transmission services, workforce issues, terrorism, acts of war, catastrophic events, and other events beyond our control,

- the impact of industry consolidation,

- the impact of increased energy conservation and use of renewable energy,

the actual outcome of uncertainties associated with assumptions and estimates requiring judgment when managing our business, applying critical accounting policies and preparing financial statements, including factors that are estimated in determining the fair value of energy contracts, such as the ability to obtain market prices and, in the absence of verifiable market prices, the appropriateness of models and model inputs (including, but not limited to, estimated contractual load obligations, unit availability, forward commodity prices, interest rates, correlation and volatility factors),

changes in accounting principles or practices, and

cost and other effects of legal and administrative proceedings and other events that may not be covered by insurance, including environmental liabilities and liabilities associated with catastrophic events.

Given these uncertainties, you should not place undue reliance on these forward looking statements. Please see the other sections of this report and our other periodic reports filed with the Securities and Exchange Commission (SEC) for more information on these factors. These forward looking statements represent our estimates and assumptions only as of the date of this report.

Changes may occur after that date, and neither Constellation Energy nor BGE assumes responsibility to update these forward looking statements.

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Item 6. Exhibits

Exhibit No. 10(a)*+	Amended and Restated 2007 Long-Term Incentive Plan. (Designated as Exhibit No. 10.1 to the Current Report on Form 8-K dated June 4, 2010, File No. 1-12869.)
Exhibit No. 10(b)+	Benefits Restoration Plan, amended and restated effective June 1, 2010.
Exhibit No. 12(a)	Constellation Energy Group, Inc. Computation of Ratio of Earnings to Fixed Charges.
Exhibit No. 12(b)	Baltimore Gas and Electric Company Computation of Ratio of Earnings to Fixed Charges and Computation of Ratio of Earnings to Combined Fixed Charges and Preferred and Preference Dividend Requirements.
Exhibit No. 31(a)	Certification of Chairman of the Board, President, and Chief Executive Officer of Constellation Energy Group, Inc. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
Exhibit No. 31(b)	Certification of Senior Vice President and Chief Financial Officer of Constellation Energy Group, Inc. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
Exhibit No. 31(c)	Certification of President and Chief Executive Officer of Baltimore Gas and Electric Company pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
Exhibit No. 31(d)	Certification of Senior Vice President and Chief Financial Officer of Baltimore Gas and Electric Company pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
Exhibit No. 32(a)	Certification of Chairman of the Board, President, and Chief Executive Officer of Constellation Energy Group, Inc. pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
Exhibit No. 32(b)	Certification of Senior Vice President and Chief Financial Officer of Constellation Energy Group, Inc. pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
Exhibit No. 32(c)	Certification of President and Chief Executive Officer of Baltimore Gas and Electric Company pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
Exhibit No. 32(d)	Certification of Senior Vice President and Chief Financial Officer of Baltimore Gas and Electric Company pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
Exhibit No. 101.INS	XBRL Instance Document
Exhibit No. 101.SCH	XBRL Taxonomy Extension Schema Document
Exhibit No. 101.PRE	XBRL Taxonomy Presentation Linkbase Document
Exhibit No. 101.LAB	XBRL Taxonomy Label Linkbase Document
Exhibit No. 101.CAL	XBRL Taxonomy Calculation Linkbase Document
Exhibit No. 101.DEF	XBRL Taxonomy Definition Linkbase Document

* Incorporated by reference.

\+ Management contract or compensatory plan or arrangement.

In accordance with Rule 402 of Regulation S-T, the XBRL related information in Exhibit 101 to this Quarterly Report on Form 10-Q shall not be deemed to be "filed" for purposes of Section 18 of the Exchange Act, or otherwise subject to the liability of that section, and shall not be incorporated by reference into any registration statement or other document filed under the Securities Act or the Exchange Act, except as shall be expressly set forth by specific reference in such filing.

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SIGNATURE

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 thereunto duly authorized.

CONSTELLATION ENERGY GROUP, INC

(Registrant)

Date: August 6, 2010

/s/ JONATHAN W. THAYER

Jonathan W. Thayer,
Senior Vice President of Constellation Energy Group, Inc. and as Principal Financial Officer

BALTIMORE GAS AND ELECTRIC COMPANY

(Registrant)

Date: August 6, 2010

/s/ KEVIN W. HADLOCK

Kevin W. Hadlock,
Senior Vice President of Baltimore Gas and Electric Company and as Principal Financial Officer