CONSTELLATION ENERGY GROUP INC
Form 10-Q
November 09, 2006

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 **September 30, 2006**

Commission File Number	Exact name of registrant as specified in its charter	IRS Employer Identification No.
1-12869	**CONSTELLATION ENERGY GROUP, INC.**	**52-1964611**
1-1910	**BALTIMORE GAS AND ELECTRIC COMPANY**	**52-0280210**

MARYLAND
(State of Incorporation of both registrants)

750 E. PRATT STREET,	**BALTIMORE, MARYLAND**	**21202**
	(Address of principal executive offices)	(Zip Code)

410-783-2800
(Registrants telephone number, including area code)

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 x No o

Indicate by check mark whether Constellation Energy Group, Inc. is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act.

(Check one):

Large accelerated filer x Accelerated filer o Non-accelerated filer o

Indicate by check mark whether Baltimore Gas and Electric Company is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act.

(Check one):

Large accelerated filer o Accelerated filer o Non-accelerated filer x

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 x

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 x

Common Stock, without par value 180,007,617 shares outstanding of

Constellation Energy Group, Inc. on October 31, 2006.

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 I FINANCIAL INFORMATION

Item 1 Financial Statements

Constellation Energy Group, Inc. and Subsidiaries

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	**2005**	**2006**	**2005**
	(In millions, except per share amounts)			
Revenues				
Nonregulated revenues	**$ 4,672.1**	$ 4,183.4	**$ 12,428.7**	$ 9,771.0
Regulated electric revenues	**649.9**	626.8	**1,652.6**	1,583.4
Regulated gas revenues	**111.7**	112.2	**671.8**	618.5
Total revenues	**5,433.7**	4,922.4	**14,753.1**	11,972.9
Expenses				
Fuel and purchased energy expenses	**4,096.5**	3,953.2	**11,416.4**	9,218.0
Operating expenses	**519.5**	415.4	**1,622.5**	1,339.3
Workforce reduction costs	**21.7**	3.9	**23.9**	3.9
Merger-related costs	**3.4**		**12.4**	
Depreciation, depletion, and amortization	**140.7**	143.3	**413.8**	407.4
Accretion of asset retirement obligations	**17.1**	15.8	**50.3**	46.2
Taxes other than income taxes	**74.9**	73.8	**222.7**	209.4
Total expenses	**4,873.8**	4,605.4	**13,762.0**	11,224.2
Income from Operations	**559.9**	317.0	**991.1**	748.7
Other Income	**8.7**	16.1	**36.5**	43.0
Fixed Charges				
Interest expense	**83.1**	75.7	**239.3**	230.2
Interest capitalized and allowance for borrowed funds used during construction	**(3.5)**	(2.1)	**(10.1)**	(7.6)
BGE preference stock dividends	**3.3**	3.3	**9.9**	9.9
Total fixed charges	**82.9**	76.9	**239.1**	232.5
Income from Continuing Operations Before Income Taxes	**485.7**	256.2	**788.5**	559.2
Income Tax Expense	**161.3**	72.1	**257.9**	138.7
Income from Continuing Operations	**324.4**	184.1	**530.6**	420.5
Income from discontinued operations, net of income taxes of $4.1, $0.5 and $12.0, respectively		1.4	**0.9**	7.4
Net Income	**$ 324.4**	$ 185.5	**$ 531.5**	$ 427.9
Earnings Applicable to Common Stock	**$ 324.4**	$ 185.5	**$ 531.5**	$ 427.9
Average Shares of Common Stock Outstanding Basic	**179.7**	178.1	**179.1**	177.5
Average Shares of Common Stock Outstanding Diluted	**181.6**	180.5	**180.9**	179.6
Earnings Per Common Share from Continuing Operations Basic	**$ 1.81**	$ 1.03	**$ 2.96**	$ 2.37
Income from discontinued operations		0.01	**0.01**	0.04
Earnings Per Common Share Basic	**$ 1.81**	$ 1.04	**$ 2.97**	$ 2.41
Earnings Per Common Share from Continuing Operations Diluted	**$ 1.79**	$ 1.02	**$ 2.93**	$ 2.34
Income from discontinued operations		0.01	**0.01**	0.04
Earnings Per Common Share Diluted	**$ 1.79**	$ 1.03	**$ 2.94**	$ 2.38
Dividends Declared Per Common Share	**$ 0.3775**	$ 0.335	**$ 1.1325**	$ 1.005

Constellation Energy Group, Inc. and Subsidiaries

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	**2005**	**2006**	**2005**
	(In millions)			
Net Income	**$ 324.4**	$ 185.5	**$ 531.5**	$ 427.9
Other comprehensive income (OCI)				
Reclassification of net loss (gain) on sales of securities from OCI to net income, net of taxes		1.6	**(0.3)**	1.5
Reclassification of net loss (gain) on hedging instruments from OCI to net income, net of taxes	**193.0**	(318.7)	**407.1**	(416.9)

Net unrealized (loss) gain on hedging instruments, net of taxes	**(369.7)**	820.8	**(1,418.7)**	906.9
Net unrealized gain on securities, net of taxes	**16.7**	6.7	**20.0**	15.3
Net unrealized (loss) gain on foreign currency, net of taxes	**(0.3)**	0.7	**0.8**	1.1
Comprehensive Income (Loss)	**$ 164.1**	$ 696.6	**$ (459.6)**	$ 935.8

See Notes to Consolidated Financial Statements.

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Constellation Energy Group, Inc. and Subsidiaries

	September 30, 2006*	***December 31, 2005***
	(In millions)	
Assets		
Current Assets		
Cash and cash equivalents	**$ 320.7**	$ 813.0
Accounts receivable (net of allowance for uncollectibles of **$53.2** and $47.4, respectively)	**2,959.5**	2,727.9
Fuel stocks	**605.7**	489.5
Materials and supplies	**204.2**	197.0
Mark-to-market energy assets	**889.3**	1,339.2
Risk management assets	**231.2**	1,244.3
Unamortized energy contract assets	**40.9**	55.6
Deferred income taxes	**472.0**	
Other	**531.3**	555.3
Total current assets	**6,254.8**	7,421.8
Investments and Other Assets		
Nuclear decommissioning trust funds	**1,170.4**	1,110.7
Investments in qualifying facilities and power projects	**312.5**	306.2
Regulatory assets (net)	**283.4**	154.3
Goodwill	**157.1**	147.1
Mark-to-market energy assets	**814.1**	1,089.3
Risk management assets	**360.3**	626.0
Unamortized energy contract assets	**120.5**	141.2
Other	**340.7**	410.6
Total investments and other assets	**3,559.0**	3,985.4
Property, Plant and Equipment		
Nonregulated property, plant and equipment	**8,928.3**	8,580.8
Regulated property, plant and equipment	**5,673.5**	5,520.5
Nuclear fuel (net of amortization)	**362.8**	302.0
Accumulated depreciation	**(4,579.1)**	(4,336.6)
Net property, plant and equipment	**10,385.5**	10,066.7
Total Assets	**$ 20,199.3**	**$ 21,473.9**

** Unaudited*

See Notes to Consolidated Financial Statements.

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Constellation Energy Group, Inc. and Subsidiaries

	*September 30, 2006**	*December 31, 2005*
	(In millions)	
Liabilities and Equity		
Current Liabilities		
Short-term borrowings	**$ 185.0**	$ 0.7
Current portion of long-term debt	**1,186.1**	491.3
Accounts payable and accrued liabilities	**1,719.9**	1,667.9
Customer deposits and collateral	**419.8**	458.9
Mark-to-market energy liabilities	**822.9**	1,348.7
Risk management liabilities	**1,120.7**	483.5
Unamortized energy contract liabilities	**412.7**	489.5
Deferred income taxes		151.4
Accrued expenses and other	**738.4**	780.4
Total current liabilities	**6,605.5**	5,872.3
Deferred Credits and Other Liabilities		
Deferred income taxes	**1,268.7**	1,180.8
Asset retirement obligations	**956.2**	908.0
Mark-to-market energy liabilities	**467.8**	912.3
Risk management liabilities	**840.6**	1,035.5
Unamortized energy contract liabilities	**1,022.3**	1,118.7
Net pension liability	**421.8**	401.4
Postretirement and postemployment benefits	**395.3**	382.6
Deferred investment tax credits	**58.9**	64.1
Other	**104.8**	101.0
Total deferred credits and other liabilities	**5,536.4**	6,104.4
Long-term Debt		
Long-term debt of Constellation Energy	**3,051.5**	3,049.1
Long-term debt of nonregulated businesses	**329.0**	357.5
First refunding mortgage bonds of BGE	**244.5**	342.8
Other long-term debt of BGE	**824.5**	861.5
6.20% deferrable interest subordinated debentures due October 15, 2043 to BGE wholly owned BGE Capital Trust II relating to trust preferred securities	**257.7**	257.7
Unamortized discount and premium	**(5.2)**	(8.0)
Current portion of long-term debt	**(1,186.1)**	(491.3)
Total long-term debt	**3,515.9**	4,369.3
Minority Interests	**21.9**	22.4
BGE Preference Stock Not Subject to Mandatory Redemption	**190.0**	190.0
Common Shareholders Equity		
Common stock	**2,698.8**	2,620.8
Retained earnings	**3,137.4**	2,810.2
Accumulated other comprehensive loss	**(1,506.6)**	(515.5)
Total common shareholders equity	**4,329.6**	4,915.5
Commitments, Guarantees, and Contingencies (see Notes)		
Total Liabilities and Equity	**$ 20,199.3**	$ 21,473.9

** Unaudited*

See Notes to Consolidated Financial Statements.

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Constellation Energy Group, Inc. and Subsidiaries

Nine Months Ended September 30,	**2006**	**2005**
	(In millions)	
Cash Flows From Operating Activities		
Net income	**$ 531.5**	$ 427.9
Adjustments to reconcile to net cash provided by operating activities		
(Gain) loss on sales of discontinued operations	**(0.9)**	2.4
Depreciation, depletion, and amortization	**417.1**	494.9
Accretion of asset retirement obligations	**50.3**	46.2
Deferred income taxes	**73.8**	7.5
Investment tax credit adjustments	**(5.2)**	(5.4)
Deferred fuel costs	**(164.7)**	12.1
Pension and postemployment benefits	**35.5**	4.0
Workforce reduction costs	**23.9**	3.9
Merger-related costs	**12.4**	
Equity in earnings of affiliates less than dividends received	**12.9**	28.3
Proceeds from derivative power sales contracts classified as financing activities under SFAS No. 149	**(38.9)**	(47.4)
Changes in		
Accounts receivable	**(367.7)**	(719.8)
Mark-to-market energy assets and liabilities	**(241.5)**	(98.6)
Risk management assets and liabilities	**(2.0)**	(51.5)
Materials, supplies, and fuel stocks	**(267.9)**	(126.0)
Other current assets	**53.9**	(186.1)
Accounts payable and accrued liabilities	**30.9**	646.2
Other current liabilities	**32.9**	665.9
Other	**(23.2)**	(5.2)
Net cash provided by operating activities	**163.1**	1,099.3
Cash Flows From Investing Activities		
Investments in property, plant and equipment	**(668.0)**	(476.9)
Acquisitions, net of cash acquired	**(133.5)**	(238.1)
Investments in nuclear decommissioning trust fund securities	**(275.0)**	(258.7)
Proceeds from nuclear decommissioning trust fund securities	**266.2**	245.5
Sales of investments and other assets	**43.5**	1.9
Contract and portfolio acquisitions	**(2.3)**	(23.7)
Proceeds from sale of discontinued operations		217.6
Issuances of loans receivable	**(65.4)**	(82.8)
Other investments	**33.8**	(28.5)
Net cash used in investing activities	**(800.7)**	(643.7)
Cash Flows From Financing Activities		
Net issuance of short-term borrowings	**184.3**	10.0
Proceeds from issuance of		
Common stock	**56.2**	66.5
Long-term debt	**122.0**	
Repayment of long-term debt	**(285.8)**	(338.4)
Common stock dividends paid	**(195.7)**	(169.1)
Proceeds from contract and portfolio acquisitions contracts	**221.3**	403.3
Proceeds from derivative power sales contracts classified as financing activities under SFAS No. 149	**38.9**	47.4
Other	**4.1**	(41.8)
Net cash provided by (used in) financing activities	**145.3**	(22.1)
Net (Decrease) Increase in Cash and Cash Equivalents	**(492.3)**	433.5
Cash and Cash Equivalents at Beginning of Period	**813.0**	706.3
Cash and Cash Equivalents at End of Period	**$ 320.7**	$ 1,139.8 *

**Includes $4.8 million related to Assets held for sale at September 30, 2005*

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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Baltimore Gas and Electric Company and Subsidiaries

	Three Months Ended September 30,		*Nine Months Ended September 30,*	
	2006	**2005**	**2006**	**2005**
			(In millions)	
Revenues				
Electric revenues	**$ 649.9**	$ 626.8	**$ 1,652.6**	$ 1,583.4
Gas revenues	**114.6**	115.9	**678.4**	626.9
Total revenues	**764.5**	742.7	**2,331.0**	2,210.3
Expenses				
Operating expenses				
Electricity purchased for resale	**391.1**	362.5	**933.8**	849.0
Gas purchased for resale	**66.4**	72.1	**448.6**	422.5
Operations and maintenance	**123.9**	112.7	**364.2**	332.5
Merger-related costs	**0.8**		**3.3**	
Depreciation and amortization	**57.2**	58.6	**172.1**	176.6
Taxes other than income taxes	**42.1**	41.9	**126.4**	126.7
Total expenses	**681.5**	647.8	**2,048.4**	1,907.3
Income from Operations	**83.0**	94.9	**282.6**	303.0
Other Income	**3.9**	1.2	**4.9**	4.7
Fixed Charges				
Interest expense	**24.8**	23.9	**73.3**	71.4
Allowance for borrowed funds used during construction	**(0.5)**	(0.6)	**(1.4)**	(1.6)
Total fixed charges	**24.3**	23.3	**71.9**	69.8
Income Before Income Taxes	**62.6**	72.8	**215.6**	237.9
Income Taxes	**23.7**	27.1	**83.3**	91.0
Net Income	**38.9**	45.7	**132.3**	146.9
Preference Stock Dividends	**3.3**	3.3	**9.9**	9.9
Earnings Applicable to Common Stock	**$ 35.6**	$ 42.4	**$ 122.4**	$ 137.0

See Notes to Consolidated Financial Statements.

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Baltimore Gas and Electric Company and Subsidiaries

	September 30, 2006*	***December 31, 2005***
	(In millions)	
Assets		
Current Assets		
Cash and cash equivalents	**$ 14.9**	$ 15.1
Accounts receivable (net of allowance for uncollectibles of **$15.4** and $13.0, respectively)	**310.7**	480.5
Accounts receivable, affiliated companies	**30.9**	1.8
Fuel stocks	**115.0**	102.7
Materials and supplies	**42.2**	40.1
Prepaid taxes other than income taxes	**28.0**	45.7
Other	**36.1**	6.5
Total current assets	**577.8**	692.4
Investments and Other Assets		
Regulatory assets (net)	**283.4**	154.3
Receivable, affiliated company	**160.0**	154.7
Other	**121.5**	144.0
Total investments and other assets	**564.9**	453.0
Utility Plant		
Plant in service		
Electric	**4,000.8**	3,891.1
Gas	**1,136.0**	1,116.7
Common	**434.0**	416.0
Total plant in service	**5,570.8**	5,423.8
Accumulated depreciation	**(1,972.5)**	(1,923.8)
Net plant in service	**3,598.3**	3,500.0
Construction work in progress	**99.8**	93.9
Plant held for future use	**2.9**	2.8
Net utility plant	**3,701.0**	3,596.7
Total Assets	**$ 4,843.7**	$ 4,742.1

** Unaudited*

See Notes to Consolidated Financial Statements.

Baltimore Gas and Electric Company and Subsidiaries

	September 30, 2006*	***December 31, 2005***
	(In millions)	
Liabilities and Equity		
Current Liabilities		
Current portion of long-term debt	**$ 565.9**	$ 469.6
Accounts payable and accrued liabilities	**164.8**	169.7
Accounts payable and accrued liabilities, affiliated companies	**134.1**	152.8
Borrowing from cash pool, affiliated company	**147.3**	3.2
Customer deposits	**70.4**	65.1
Accrued taxes	**19.2**	35.5
Accrued expenses and other	**86.0**	79.6
Total current liabilities	**1,187.7**	975.5
Deferred Credits and Other Liabilities		
Deferred income taxes	**669.0**	608.9
Postretirement and postemployment benefits	**278.1**	277.7
Deferred investment tax credits	**13.9**	15.1
Other	**17.7**	19.0
Total deferred credits and other liabilities	**978.7**	920.7
Long-term Debt		
First refunding mortgage bonds of BGE	**244.5**	342.8
Other long-term debt of BGE	**824.5**	861.5
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
Long-term debt of nonregulated business	**25.0**	25.0
Unamortized discount and premium	**(1.8)**	(2.3)
Current portion of long-term debt	**(565.9)**	(469.6)
Total long-term debt	**784.0**	1,015.1
Minority Interest	**18.2**	18.3
Preference Stock Not Subject to Mandatory Redemption	**190.0**	190.0
Common Shareholder s Equity		
Common stock	**912.2**	912.2
Retained earnings	**772.2**	709.6
Accumulated other comprehensive income	**0.7**	0.7
Total common shareholder s equity	**1,685.1**	1,622.5
Commitments, Guarantees, and Contingencies (see Notes)		
Total Liabilities and Equity	**$ 4,843.7**	$ 4,742.1

* *Unaudited*

See Notes to Consolidated Financial Statements.

Baltimore Gas and Electric Company and Subsidiaries

Nine Months Ended September 30,	2006	2005
	(In millions)	
Cash Flows From Operating Activities		
Net income	**$ 132.3**	$ 146.9
Adjustments to reconcile to net cash provided by operating activities		
Depreciation and amortization	**180.1**	187.5
Deferred income taxes	**59.0**	(6.4)
Investment tax credit adjustments	**(1.2)**	(1.3)
Deferred fuel costs	**(164.7)**	12.1
Pension and postemployment benefits	**(2.5)**	(5.2)
Merger-related costs	**3.3**	
Allowance for equity funds used during construction	**(2.6)**	(2.8)
Changes in		
Accounts receivable	**169.8**	22.1
Receivables, affiliated companies	**(29.1)**	(33.0)
Materials, supplies, and fuel stocks	**(14.4)**	(22.9)
Other current assets	**(11.7)**	(20.9)
Accounts payable and accrued liabilities	**(8.3)**	(3.0)
Accounts payable and accrued liabilities, affiliated companies	**(18.7)**	(20.1)
Other current liabilities	**(3.7)**	9.5
Other	**(12.0)**	(23.1)
Net cash provided by operating activities	**275.6**	239.4
Cash Flows From Investing Activities		
Utility construction expenditures (excluding equity portion of allowance for funds used during construction)	**(225.2)**	(199.2)
Change in cash pool at parent	**144.1**	10.8
Other	**10.3**	(14.5)
Net cash used in investing activities	**(70.8)**	(202.9)
Cash Flows From Financing Activities		
Distribution to parent	**(59.8)**	
Repayment of long-term debt	**(135.3)**	(23.5)
Preference stock dividends paid	**(9.9)**	(9.9)
Net cash used in financing activities	**(205.0)**	(33.4)
Net (Decrease) Increase in Cash and Cash Equivalents	**(0.2)**	3.1
Cash and Cash Equivalents at Beginning of Period	**15.1**	8.2
Cash and Cash Equivalents at End of Period	**$ 14.9**	$ 11.3

See Notes to Consolidated Financial Statements.

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.

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.

Subsequent Events

Termination of Merger Agreement with FPL Group, Inc.

On October 24, 2006, Constellation Energy and FPL Group, Inc. (FPL Group) agreed to terminate the Agreement and Plan of Merger the parties had entered into on December 18, 2005.

Gas-Fired Plants

In October 2006, we announced an agreement to sell the following natural gas-fired plants owned by our merchant energy business for $1.635 billion:

Facility	Capacity (MW)	Unit Type	Location
High Desert	830	Combined Cycle	California
Rio Nogales	800	Combined Cycle	Texas
Holland	665	Combined Cycle	Illinois
University Park	300	Peaking	Illinois
Big Sandy	300	Peaking	West Virginia
Wolf Hills	250	Peaking	Virginia

We expect the transaction to close by the end of 2006 or the first quarter of 2007. We estimate that we will recognize a pre-tax gain of approximately $250 million and we expect to receive approximately $1.5 billion in cash after tax payments on the gain. We expect to apply the proceeds from the sale to reduce debt and invest in our business or repurchase equity.

In October 2006, we designated these plants as held for sale and we reclassified the assets associated with these gas-fired plants to Assets held for sale and the liabilities to Liabilities associated with assets held for sale in our Consolidated Balance Sheets, we ceased recording depreciation expense, and discontinued hedge accounting for these facilities. The assets and liabilities associated with these gas-fired plants will be removed from our Consolidated Balance Sheets at closing.

Variable Interest Entities

We have a significant interest in the following variable interest entities (VIE) for which we are not the primary beneficiary:

VIE	Nature of Involvement	Date of Involvement
Power projects and fuel supply entities	Equity investment and guarantees	Prior to 2003
Power contract monetization entities	Power sale agreements, loans, and guarantees	March 2005
Oil and gas fields	Equity investment	May 2006
Retail power supply	Power sale agreement	September 2006

We discuss the nature of our involvement with the power contract monetization VIEs in detail in *Note 4* to our 2005 Annual Report on Form 10-K.

The following is summary information available as of September 30, 2006 about the VIEs in which we have a significant interest, but are not the primary beneficiary:

	Power Contract Monetization VIEs	**All Other VIEs**	**Total**
		(In millions)	
Total assets	$ 833.6	$ 396.3	$ 1,229.9
Total liabilities	652.3	167.6	819.9
Our ownership interest		54.5	54.5
Other ownership interests	181.3	174.2	355.5
Our maximum exposure to loss	68.9	102.7	171.6

The maximum exposure to loss represents 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 guarantees associated with these entities. Our maximum exposure to loss as of September 30, 2006 consists of the following:

- outstanding receivables, loans, and letters of credit totaling $104.5 million,
- the carrying amount of our investment totaling $54.4 million, and
- debt and performance guarantees totaling $12.7 million.

We assess the risk of a loss equal to our maximum exposure to be remote.

Merger-Related Costs

We incurred costs during the quarter ended September 30, 2006 related to the proposed merger with FPL Group. The merger was terminated on October 24, 2006. These costs totaled $3.4 million pre-tax for the quarter ended September 30, 2006 and $12.4 million pre-tax for the nine months ended September 30, 2006. Through September 30, 2006, we have recognized a cumulative total of $29.4 million pre-tax of merger costs. Currently, we estimate our total pre-tax merger-related costs will be approximately $35 million.

Workforce Reduction Costs

In March 2006, we approved a restructuring of the workforce at our Ginna nuclear facility. In connection with this restructuring, 32 employees were terminated. During the quarter ended March 31, 2006, we recognized costs of $2.2 million pre-tax related to recording a liability for severance and other benefits under our existing benefit programs.

The following table summarizes the status of the involuntary severance liability for Ginna at September 30, 2006:

	(In millions)
Initial severance liability balance	$ 2.2
Amounts recorded as pension and postretirement liabilities	(0.3)
Net cash severance liability	1.9
Cash severance payments	(1.0)
Other	
Severance liability balance for Ginna at September 30, 2006	$ 0.9

In July 2006, we announced a planned restructuring of the workforce at our Nine Mile Point nuclear facility. We recognized costs during the quarter ended September 30, 2006 of $15.1 million pre-tax related to the elimination of 126 positions associated with this restructuring. We also initiated a restructuring of the workforce at our Calvert Cliffs nuclear facility during the third quarter of 2006 and we recognized costs of $3.1 million pre-tax related to the elimination of 32 positions associated with this restructuring.

In addition, as a result of the Nine Mile Point restructuring, we incurred a pre-tax settlement charge of $3.5 million in accordance with Statement of Financial Accounting Standards (SFAS) No. 88, *Employers Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits*. We discuss the settlement charges that we recorded during 2006 in the *Pension and Postretirement Benefits* section on page 16.

Discontinued Operations

In the fourth quarter of 2005, we completed the sale of Constellation Power International Investments, Ltd. We recognized an after-tax gain of $0.9 million for the nine months ended September 30, 2006 due to the resolution of an outstanding contingency related to the sale. We discuss the details of the outstanding contingency in *Note 2* of our 2005 Annual Report on Form 10-K.

Earnings Per Share

Basic earnings per common share (EPS) is computed by dividing earnings applicable 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 September 30,		Nine Months Ended September 30,	
	2006	**2005**	**2006**	**2005**
	(In millions)			
Non-dilutive stock options	**2.0**		**2.0**	
Dilutive common stock equivalent shares	**1.9**	2.4	**1.8**	2.1

Stock-Based Compensation

Under our long-term incentive plans, we granted stock options, performance-based units, performance and service-based restricted stock, and equity to officers, key employees, and members of the Board of Directors.

We adopted the provisions of SFAS No. 123 Revised (SFAS No. 123R), *Share-Based Payment*, on October 1, 2005, as described in more detail in *Note 1* of our 2005 Annual Report on Form 10-K. Under SFAS No. 123R, we recognize compensation cost ratably or in tranches (depending if the award has cliff or graded vesting) over the period during which an employee is required to provide service in exchange for the award, which is typically a one to five-year period. We use a forfeiture assumption to estimate the number of awards that are expected to vest during the service period, and we ultimately true-up the estimated expense to the actual expense associated with vested awards. We estimate the fair value of stock option awards on the date of grant using the Black-Scholes option-pricing model, and we re-measure the fair value of liability awards each reporting period.

The following table illustrates the pro-forma effect on net income and earnings per share for all outstanding stock options and stock awards during the quarter and nine months ended September 30, 2005, when the fair value provisions of SFAS No. 123R were not in effect. We do not capitalize any portion of our stock-based compensation.

	Quarter Ended September 30, 2005	Nine Months Ended September 30, 2005
	(In millions, except per share amounts)	
Net income, as reported	$ 185.5	$ 427.9
Add: Stock-based compensation expense determined under intrinsic value method and included in reported net income, net of related tax effects	7.8	17.8
Deduct: Stock-based compensation expense determined under fair value based method for all awards, net of related tax effects	(10.1)	(24.5)
Pro-forma net income	$ 183.2	$ 421.2
Earnings per share:		
Basic as reported	$ 1.04	$ 2.41
Basic pro forma	$ 1.03	$ 2.37
Diluted as reported	$ 1.03	$ 2.38
Diluted pro forma	$ 1.01	$ 2.34

Accretion of Asset Retirement Obligations

SFAS No. 143, *Accounting for Asset Retirement Obligations,* provides the accounting requirements for recognizing an estimated liability for legal obligations associated with the retirement of tangible long-lived assets. Financial Accounting Standards Board (FASB) Interpretation (FIN) 47, *Accounting for Conditional Asset Retirement Obligations an interpretation of FASB Statement No. 143,* clarifies that obligations that are conditional upon a future event are subject to the provisions of SFAS No. 143.

We measure asset retirement obligations at fair value when incurred and capitalize a corresponding amount as part of the book value of the related long-lived assets. The increase in the capitalized cost is included in determining depreciation expense over the estimated useful life of these assets. Since the fair value of the asset retirement obligations is determined using a present value approach, accretion of the liability due to the passage of time is recognized each period to Accretion of asset retirement obligations in our Consolidated Statements of Income until the settlement of the liability. We record a gain or loss when the liability is settled after retirement.

The change in our Asset retirement obligations liability during 2006 was as follows:

	(In millions)
Liability at January 1, 2006	$ 908.0
Accretion expense	50.3
Liabilities incurred	0.4
Liabilities settled	(0.1)
Revisions to expected future cash flows	(2.4)
Other	
Liability at September 30, 2006	$ 956.2

Acquisitions

Gas Properties

In the first quarter of 2006, we acquired working interests in gas and oil producing properties for approximately $100 million in cash. We purchased leases, producing wells, and related equipment. We have included the results of operations in our merchant energy business segment since the date of acquisition.

Cogenex

In April 2005, we acquired Cogenex Corporation from Alliant Energy Corporation. We include Cogenex with our other nonregulated businesses and have included their results in our consolidated financial statements since the date of acquisition. Cogenex is a North American energy services firm providing consulting and technology solutions to industrial, institutional, and governmental customers. We acquired 100% ownership of Cogenex for $34.9 million. We acquired cash of $14.4 million as part of the purchase.

Our final purchase price allocation for the net assets acquired is as follows:

At April 1, 2005	*(In millions)*
Cash	$ 14.4
Other Current Assets	12.4
Total Current Assets	26.8
Net Property, Plant and Equipment	
Other Assets	34.9
Total Assets Acquired	61.7
Current Liabilities	(8.0)
Deferred Credits and Other Liabilities	(18.8)
Net Assets Acquired	$ 34.9

We believe that the pro-forma impact of the Cogenex acquisition would not have been material to our results of operations in 2005.

Information by Operating Segment

Our reportable operating segments are Merchant Energy, Regulated Electric, and Regulated Gas:

♦ Our merchant energy business is nonregulated and includes:

full requirements load-serving sales of energy, capacity, and ancillary services to utilities and commercial, industrial, and governmental customers,

structured transactions and risk management services for various customers (including hedging of output from generating facilities and fuel costs),

deployment of risk capital through portfolio management and trading activities,

gas retail energy products and services to commercial, industrial, and governmental customers,

fossil, nuclear, and interests in hydroelectric generating facilities and qualifying facilities, fuel processing facilities, and power projects in the United States,

products and services to upstream (exploration and production) and downstream (transportation and storage) wholesale natural gas customers,

coal sourcing services for the variable or fixed supply needs of North American and international power generators, and

generation operations and maintenance services.♦ 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 remaining nonregulated businesses:

♦ design, construct, and operate heating, cooling, and cogeneration facilities for commercial, industrial, and municipal customers throughout North America, and

♦ provide home improvements, service electric and gas appliances, service heating, air conditioning, plumbing, electrical, and indoor air quality systems, and provide natural gas marketing to residential customers in Central Maryland.

In addition, we own several investments that we do not consider to be core operations. These include financial investments and real estate projects.

Our Merchant Energy, Regulated Electric, and Regulated Gas reportable segments are strategic businesses based principally upon regulations, products, and services that require different technology 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 on the next page.

	Reportable Segments					
	Merchant Energy Business	**Regulated Electric Business**	**Regulated Gas Business**	**Other Nonregulated Businesses**	**Eliminations**	**Consolidated**
			(In millions)			
For the three months ended September 30,						
2006						
Unaffiliated revenues	**$ 4,626.6**	**$ 649.9**	**$ 111.7**	**$ 45.5**	**$**	**$ 5,433.7**
Intersegment revenues	**422.4**		**2.9**		**(425.3)**	
Total revenues	**5,049.0**	**649.9**	**114.6**	**45.5**	**(425.3)**	**5,433.7**
Net income (loss)	**284.8**	**42.8**	**(7.3)**	**4.1**		**324.4**
2005						
Unaffiliated revenues	$ 4,134.2	$ 626.8	$ 112.2	$ 49.2	$	$ 4,922.4
Intersegment revenues	263.0		3.7	0.1	(266.8)	
Total revenues	4,397.2	626.8	115.9	49.3	(266.8)	4,922.4
(Loss) income from discontinued operations	(0.2)			1.6		1.4
Net income (loss)	141.5	51.1	(8.6)	1.5		185.5
For the nine months ended September 30,						
2006						
Unaffiliated revenues	**$ 12,259.5**	**$ 1,652.6**	**$ 671.8**	**$ 169.2**	**$**	**$ 14,753.1**
Intersegment revenues	**862.1**		**6.6**	**0.1**	**(868.8)**	
Total revenues	**13,121.6**	**1,652.6**	**678.4**	**169.3**	**(868.8)**	**14,753.1**
Income from discontinued operations				**0.9**		**0.9**
Net income	**400.1**	**96.3**	**26.3**	**8.8**		**531.5**
2005						
Unaffiliated revenues	$ 9,627.2	$ 1,583.4	$ 618.5	$ 143.8	$	$ 11,972.9
Intersegment revenues	685.2		8.4	0.6	(694.2)	
Total revenues	10,312.4	1,583.4	626.9	144.4	(694.2)	11,972.9
Income from discontinued operations	2.9			4.5		7.4
Net income	285.8	120.0	17.3	4.8		427.9

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Regulatory Assets (net) Rate Stabilization Deferral

During the second quarter of 2006, the Maryland legislature approved Senate Bill 1, which imposes a rate stabilization measure that caps rate increases by BGE for residential customers at 15% from July 1, 2006 to May 31, 2007. As a result, BGE is recording a regulatory asset on its Consolidated Balance Sheets equal to the difference between the costs to purchase power and the revenues collected from customers, as well as related carrying charges from July 1, 2006 to May 31, 2007. During the third quarter of 2006, BGE deferred $176.0 million of purchased power costs and carrying charges as a regulatory asset related to the rate stabilization plan. BGE will amortize the regulatory asset to earnings over a period not to exceed ten years once collection from customers begins.

Pension and Postretirement Benefits

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

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2006	**2005**	**2006**	**2005**
	(In millions)			
Components of net periodic pension benefit cost				
Service cost	**$ 11.9**	$ 11.0	**$ 36.5**	$ 33.5
Interest cost	**22.0**	20.7	**66.5**	62.6
Expected return on plan assets	**(23.6)**	(25.3)	**(72.1)**	(74.8)
Amortization of unrecognized prior service cost	**1.4**	1.4	**4.2**	4.3
Recognized net actuarial loss	**9.2**	6.5	**28.0**	18.6
Amount capitalized as construction cost	**(3.1)**	(1.7)	**(9.8)**	(5.4)
Net periodic pension benefit cost (1)	**$ 17.8**	$ 12.6	**$ 53.3**	$ 38.8

(1) The amounts shown above do not reflect a settlement charge of $7.6 million recorded in the third quarter of 2006 related to one of our qualified pension plans and $3.9 million in the third quarter of 2005. Net periodic pension benefit cost excludes a reduction in termination benefits of $0.4 million in 2005. BGE s portion of our net periodic pension benefit cost was $8.9 million for the quarter ended September 30, 2006 and $5.6 million for the quarter ended September 30, 2005. BGE s portion of our net periodic pension benefit cost was $27.1 million for the nine months ended September 30, 2006 and $16.1 million for the nine months ended September 30, 2005.

In the third quarter of 2006, we recorded a pre-tax settlement charge of $7.6 million in our Consolidated Statements of Income for one of our qualified plans under SFAS No. 88, of which $3.5 million related to our Nine Mile Point workforce restructuring. We discuss our workforce restructurings in the *Workforce Reduction Costs* section on page 12. This charge reflects the recognition of the portion of deferred actuarial gains and losses associated with employees who elected to receive their pension benefit in the form of a lump-sum payment. In accordance with SFAS No. 88, a settlement charge must be recognized at the point in time when lump-sum payments exceed annual pension plan service and interest cost, which occurred in July 2006. We expect to record approximately $7 million pre-tax of additional settlement charges during the remainder of 2006 as employees continue to receive lump-sum payments from this plan.

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

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2006	**2005**	**2006**	**2005**
	(In millions)			
Components of net periodic postretirement benefit cost				
Service cost	**$ 1.9**	$ 2.0	**$ 6.1**	$ 5.7
Interest cost	**6.0**	6.0	**18.8**	17.8
Amortization of transition obligation	**0.6**	0.6	**1.7**	1.6
Amortization of unrecognized prior service cost	**(0.9)**	(0.9)	**(2.8)**	(2.6)
Recognized net actuarial loss	**1.6**	1.7	**5.2**	4.8
Amount capitalized as construction cost	**(2.0)**	(2.0)	**(6.3)**	(5.9)
Net periodic postretirement benefit cost (1)	**$ 7.2**	$ 7.4	**$ 22.7**	$ 21.4

(1) BGE s portion of our net periodic postretirement benefit cost was $6.0 million for the quarter ended September 30, 2006 and $6.8 million for the quarter ended September 30, 2005. BGE s portion of our net periodic postretirement benefit costs was $18.7 million for the nine months ended September 30, 2006 and $18.8 million for the nine months ended September 30, 2005.

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 $3 million in pension benefit payments for our non-qualified pension plans and approximately $26 million for retiree health and life insurance benefit payments during 2006. We contributed $52 million to our qualified pension plans in March 2006, even though there was no IRS required minimum contribution in 2006.

Financing Activities

At September 30, 2006, we had $185.0 million of commercial paper outstanding, and at November 3, 2006 we had no commercial paper outstanding.

Constellation Energy had committed bank lines of credit under four credit facilities of $3.6 billion at September 30, 2006. We discuss these facilities in more detail in *Note 8* of our 2005 Annual Report on Form 10-K. These facilities can issue letters of credit up to $3.6 billion. Letters of credit issued under all of our facilities totaled $1.8 billion at September 30, 2006.

In October 2006, we activated a $1.0 billion 364-day credit facility expiring in October 2007. We can borrow up to $1.0 billion directly from the banks or use the facility to issue letters of credit up to $500.0 million.

In May 2006, we issued $122.0 million of tax-exempt variable rate notes to refinance tax-exempt pollution control loans. We used $75.0 million of the net proceeds to refinance a 6.00% pollution control revenue refunding loan in June 2006 and in July 2006 we used the remaining $47.0 million of proceeds to refinance a 5.55% pollution control revenue refunding loan. As discussed in *Note 9* of our 2005 Annual Report on Form 10-K, at December 31, 2005, BGE remained contingently liable for an outstanding balance of $269.8 million of tax-exempt debt that was transferred to our merchant energy business. As a result of refinancing $122.0 million of this tax-exempt debt, BGE is only contingently liable for $147.8 million.

In October 2006, BGE issued $300.0 million of 5.90% Senior Unsecured Notes, due October 1, 2016 and $400.0 million of 6.35% Senior Unsecured Notes, due October 1, 2036. We expect to use the proceeds from these issuances for general corporate purposes, including refinancing the following long-term debt of BGE:

- ♦ $300.0 million of 5.25% Notes, due December 15, 2006,
- ♦ $122.0 million of 7.5% First Refunding Mortgage Bonds, due January 15, 2007, and
- ♦ $10.0 million of 6.70% Medium-term Notes, Series D, due December 1, 2006.

Additionally, under our employee benefit plans and shareholder investment plans we issued $56.2 million of common stock during the nine months ended September 30, 2006.

Income Taxes

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

	Quarter Ended September 30, 2006	2005	Nine Months Ended September 30, 2006	2005
	(In millions)			
Income from continuing operations before income taxes (excluding BGE preference stock dividends)	**$ 489.0**	$ 259.5	**$ 798.4**	$ 569.1
Statutory federal income tax rate	**35 %**	35 %	**35 %**	35 %
Income taxes computed at statutory federal rate	**171.1**	90.8	**279.4**	199.2
(Decreases) increases in income taxes due to:				
Synthetic fuel tax credits	**(15.2)**	(28.1)	**(91.2)**	(80.1)
Estimated tax credit phase-out	**6.4**		**48.0**	
Phase-out true-up from prior periods	**(19.0)**		**(11.5)**	
State income taxes, net of federal tax benefit	**19.0**	10.8	**33.1**	24.0
Other	**(1.0)**	(1.4)	**0.1**	(4.4)
Total income taxes	**$ 161.3**	$ 72.1	**$ 257.9**	$ 138.7
Effective tax rate	**33.0 %**	27.8 %	**32.3 %**	24.4 %

Synthetic fuel tax credits are net of our expectation of a 42% phase-out in 2006 based on forward market prices and volatilities at September 30, 2006. We recorded the effect of this phase-out estimate as a reduction in tax credits of $6.4 million during the quarter ended September 30, 2006, and we also recorded a $19.0 million increase in tax credits to reflect the effect of the change in estimate of the tax credit phase-out of 68% associated with the first six months of 2006 production to our estimate at September 30, 2006 of 42%.

Based on forward market prices and volatilities as of October 26, 2006, we estimate a 36% tax credit phase-out for the year 2006. The expected amount of synthetic fuel tax credits phased-out may change materially from period to period as a result of continued changes in oil prices.

Commitments, Guarantees, and Contingencies

We have made substantial commitments in connection with our merchant energy, 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 merchant energy business enters 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 2006 and 2020. In addition, our merchant energy business enters into long-term contracts for the capacity and transmission rights for the physical delivery of energy to meet our obligations to our customers. These contracts expire in various years between 2006 and 2019.

Our merchant energy business also has 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 2007 and 2009. Our regulated gas business has gas supply, transportation, and storage contracts that expire between 2006 and 2028. As discussed in *Note 1* of our 2005 Annual Report on Form 10-K, the costs under these contracts are fully recoverable by our regulated businesses.

Our other nonregulated businesses have committed to gas purchases, as well as to contribute additional capital for construction programs and joint ventures in which they have an interest.

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

At September 30, 2006, the total amount of commitments was $7,686.6 million. These commitments are primarily related to our merchant energy business.

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 2017 and provide for the sale of energy to electricity distribution utilities and certain retail customers. Our power sales contracts associated with our power plants extend for terms into 2014 and provide for the sale of all or a portion of the actual output of certain of our power plants. All long-term contracts were executed at pricing that approximated market rates, including profit margin, at the time of execution.

Guarantees

The terms of our guarantees are as follows:

	Expiration				
	2006	2007-2008	2009-2010	Thereafter	Total
	(In millions)				
Competitive supply	$ 3,873.6	$ 3,254.5	$ 342.4	$ 2,263.9	$ 9,734.4
Other	0.6	15.2	1.4	1,289.8	1,307.0
Total	$ 3,874.2	$ 3,269.7	$ 343.8	$ 3,553.7	$ 11,041.4

At September 30, 2006, we had a total of $11,041.4 million in guarantees outstanding related to loans, credit facilities, and contractual performance of certain of our subsidiaries as described below. These guarantees do not represent our incremental obligations, and we do not expect to fund the full amount under these guarantees.

♦ Constellation Energy guaranteed $9,734.4 million on behalf of our subsidiaries for competitive supply activities. These guarantees are put into place in order to allow our subsidiaries the flexibility needed to conduct business with counterparties without having to post other forms of collateral. While the face amount of these guarantees is $9,734.4 million, our calculated fair value of obligations covered by these guarantees was $3,114.9 million at September 30, 2006. If the parent company was required to fund these subsidiary obligations, the total amount based on September 30, 2006 market prices would be $3,114.9 million. The recorded fair value of obligations in our Consolidated Balance Sheets for guarantees was $1,234.9 million at September 30, 2006.

♦ Constellation Energy guaranteed $945.0 million primarily on behalf of our nuclear generating facilities mostly due to nuclear insurance and for credit support to ensure these plants have funds to meet expenses and obligations to safely operate and maintain the plants.

♦ Constellation Energy guaranteed $62.6 million on behalf of our other nonregulated businesses primarily for loans and performance bonds of which $25.0 million was recorded in our Consolidated Balance Sheets at September 30, 2006.

♦ Our merchant energy business guaranteed $29.2 million for loans and other performance guarantees related to certain power projects in which we have an investment.

♦ Our other nonregulated businesses guaranteed $6.9 million for performance bonds.

♦ BGE guaranteed two-thirds of certain debt of Safe Harbor Water Power Corporation, an unconsolidated investment. At September 30, 2006, Safe Harbor Water Power Corporation had outstanding debt of $20.0 million. The maximum amount of BGE s guarantee is $13.3 million.

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

The total fair value of the obligations for our guarantees recorded in our Consolidated Balance Sheets at September 30, 2006 was $1.3 billion and not the $11.0 billion of total guarantees. We assess the risk of loss from these guarantees to be minimal.

Environmental Matters

Solid and Hazardous Waste

The Environmental Protection Agency (EPA) and several state agencies have notified us that we are considered a potentially responsible party with respect to the clean-up of certain environmentally contaminated sites. We cannot estimate the final clean-up costs for all of these sites, but the current estimated costs for, and current status of, each site is described in more detail below.

<u>Metal Bank</u>

In 1997, the EPA, under the Comprehensive Environmental Response, Compensation and Liability Act (Superfund), issued a Record of Decision (ROD) for the proposed clean-up at the Metal Bank of America site, a metal reclaimer in Philadelphia. We had previously recorded a liability in our Consolidated Balance Sheets for BGE s 15.47% share of probable clean-up costs. The EPA and potentially responsible parties, including BGE, filed cost recovery claims against Metal Bank of America for an equitable share of expected site remediation costs. In March 2006, all claims were settled. Under the terms of the settlement, the potentially responsible parties will remediate the site and the costs of the clean-up will be paid from funds held in trust for that purpose. BGE is not required to contribute to the trust and we do not believe the potentially responsible parties will incur clean-up costs in excess of the amount held by the trust; therefore, in March 2006, we reversed the previously recorded liability.

<u>68th Street Dump</u>

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 fully indemnified by a wholly-owned affiliate of Constellation Energy for costs related to this settlement, as well as any clean-up costs. The clean-up costs will not be known until the investigation is complete. However, those costs could have a material effect on our financial results.

<u>Kane and Lombard</u>

The EPA issued its ROD for the Kane and Lombard Drum site located in Baltimore, Maryland on September 30, 2003, which specified the clean-up plan for the site, consisting of enhanced reductive dechlorination, a soil management plan, and institutional controls. An EPA order requiring cleanup of the site by 18 parties, including Constellation Energy, is expected to become effective by the end of 2006. The EPA estimates that total clean-up costs will be approximately $7 million. Our share of site-related costs will be 11.1% of the total. We recorded a liability in our Consolidated Balance Sheets for our share of the clean-up costs that we believe is probable.

<u>Spring Gardens</u>

In December 1996, BGE signed a consent order with the Maryland Department of the Environment that requires it to implement remedial action plans for contamination at and around the Spring Gardens site, located in Baltimore, Maryland. The Spring Gardens site was once used to manufacture gas from coal and oil. Based on the remedial action plans, BGE estimates its probable clean-up costs will total $47 million. BGE has recorded these costs as a liability in its Consolidated Balance Sheets and has deferred these costs, net of accumulated amortization and amounts it recovered from insurance companies, as a regulatory asset. Based on the results of studies at this site, it is reasonably possible that additional costs could exceed the amount BGE has recognized by approximately $14 million. Through September 30, 2006, BGE has spent approximately $40 million for remediation at this site.

BGE also has investigated other small sites where gas was manufactured in the past. We do not expect the clean-up costs of the remaining smaller sites to have a material effect on our financial results.

Air Quality

In late July 2005, we received two Notices of Violation (NOVs) from the Placer County Air Pollution Control District, Placer County California (District) alleging that the Rio Bravo Rocklin facility located in Lincoln, California had violated certain District air emission regulations. We have a combined 50% ownership interest in the partnership which owns the Rio Bravo Rocklin facility. The NOVs allege a total of 38 violations between January 2003 and March 2005 of either the facility s air permit or federal, state, and county air emission standards related to nitrogen oxide, carbon monoxide, and particulate emissions, as well as violations of certain monitoring and reporting requirements during that time period. The maximum civil penalties for the alleged violations range from $10,000 to $40,000 per violation. Management of the Rio Bravo Rocklin facility is currently discussing the allegations in the NOVs with District representatives; and therefore, it is not possible to determine the actual liability, if any, of the partnership that owns the Rio Bravo Rocklin facility.

Litigation

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

Western Power Markets

City of Tacoma v. AEP, et al., The City of Tacoma, on June 7, 2004, in the U.S. District Court, Western District of Washington, filed a complaint against over 60 companies, including Constellation Energy Commodities Group, Inc. (CCG). The complaint alleges that the defendants engaged in manipulation of electricity markets resulting in prices for power in the western power markets that were substantially above what market prices would have been in the absence of the alleged unlawful contracts, combinations and conspiracy in violation of Section 1 of the Sherman Act. The complaint further alleges that the total amount of damages is unknown, but is estimated to exceed $175 million. On February 11, 2005, the Court granted the defendants motion to dismiss the action based on the Court s lack of jurisdiction over the claims in question. The plaintiff has appealed the dismissal of the action to the Ninth Circuit Court of Appeals. We believe that we have meritorious defenses to this action and intend to defend against it vigorously. However, we cannot predict the timing, or outcome, of this case, or its possible effect on our financial results.

Mercury

Beginning in 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.

In rulings applicable to all but six of the cases, involving claims related to approximately 50 children, the Circuit Court for Baltimore City dismissed with prejudice all claims against BGE and Constellation Energy. 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 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 has been involved in several actions concerning asbestos. The actions are based upon the theory of premises liability, alleging that BGE knew of and exposed individuals to an asbestos hazard. BGE and numerous other parties are defendants in these cases.

Approximately 522 individuals who were never employees of BGE 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 in these actions. To date, most asbestos claims against us 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. The remaining claims are currently pending in state courts in Maryland and Pennsylvania.

BGE does not know the specific facts necessary to estimate its potential liability for these claims. The specific facts BGE does not know include:

- the identity of BGE s 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.

Revenue Sufficiency Guarantee Costs

In April 2006, the Federal Energy Regulatory Commission (FERC) issued an order requiring the Midwest Independent System Operator (MISO) to retroactively re-allocate revenue sufficiency guarantee costs (RSGs) for the period April 2005 to present based on the FERC s finding that MISO violated its tariff and incorrectly allocated RSGs among market participants. The re-allocation of RSGs would result in some participants recognizing additional expense and others receiving refunds.

In May 2006, the MISO filed a motion with FERC seeking a stay of the FERC order. The motion was granted by FERC delaying the implementation of the original order until after the issuance of an order on rehearing. In May 2006, we and other market participants filed requests for rehearing with FERC.

In October 2006, FERC issued an order on rehearing that reversed the original retroactive re-allocation of RSGs. Based on this order we estimate the impact of the RSG re-allocation, if any, to be immaterial to our financial results. However, the order may be appealed and we cannot predict the ultimate timing or outcome of any appeal.

Insurance

We discuss our nuclear and non-nuclear insurance programs in *Note 12* of our 2005 Annual Report on Form 10-K.

SFAS No. 133 Hedging Activities

We are exposed to market risk, including changes in interest rates and the impact of market fluctuations in the price and transportation costs of electricity, natural gas, and other commodities. We discuss our market risk in more detail in our 2005 Annual Report on Form 10-K.

Interest Rates

We use interest rate swaps to manage our interest rate exposures associated with new debt issuances and to optimize the mix of fixed and floating-rate debt. The swaps used to manage our exposure prior to the issuance of new debt are designated as cash-flow hedges under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, *as amended*, with the effective portion of gains and losses, net of associated deferred income tax effects, recorded in Accumulated other comprehensive income in our Consolidated Balance Sheets, in anticipation of planned financing transactions. We reclassify gains and losses on the hedges from Accumulated other comprehensive income into Interest expense in our Consolidated Statements of Income during the periods in which the interest payments being hedged occur.

The swaps used to optimize the mix of fixed and floating-rate debt are designated as fair value hedges under SFAS No. 133. 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, and we record any changes in fair value of the swaps and the debt in Risk management assets and liabilities and 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.

Accumulated other comprehensive income includes net unrealized pre-tax gains on interest rate cash-flow hedges terminated upon debt issuance totaling $13.2 million at September 30, 2006 and $15.4 million at December 31, 2005. We expect to reclassify $1.3 million of pre-tax net gains on these cash-flow hedges from Accumulated other comprehensive income into Interest expense during the next twelve months.

During 2004, to optimize the mix of fixed and floating-rate debt, we entered into interest rate swaps qualifying as fair value hedges relating to $450.0 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 pre-tax loss of $0.4 million at September 30, 2006 and an unrealized pre-tax loss of $0.9 million at December 31, 2005 and was recorded as an increase in our Risk management liabilities and a decrease in our Long-term debt. We have not recognized any hedge ineffectiveness on these interest rate swaps.

Commodity Prices

At September 30, 2006 our merchant energy business had designated certain purchase and sale contracts as cash-flow hedges of forecasted transactions for the years 2006 through 2015 under SFAS No. 133.

Under the provisions of SFAS No. 133, we record gains and losses on energy derivative contracts designated as cash-flow hedges of forecasted transactions in Accumulated other comprehensive income in our Consolidated Balance Sheets prior to the settlement of the anticipated hedged physical transaction. We reclassify these gains or losses into earnings upon settlement of the underlying hedged transaction. We record derivatives used for hedging activities from our merchant energy business in Risk management assets and liabilities in our Consolidated Balance

Sheets.

Our merchant energy business has net unrealized pre-tax losses of $2,143.7 million at September 30, 2006 and $517.1 million at December 31, 2005 on these hedges recorded in Accumulated other comprehensive income. We expect to reclassify $1,262.5 million of net pre-tax losses on cash-flow hedges from Accumulated other comprehensive income into earnings during the next twelve months based on the market prices at September 30, 2006. However, the actual amount reclassified into earnings could vary from the amounts recorded at September 30, 2006 due to future changes in market prices.

We recognized into earnings a pre-tax loss of $1.9 million for the quarter ended September 30, 2006 and a pre-tax loss of $4.8 million for the quarter ended September 30, 2005 related to the ineffective portion of our hedges.

We recognized into earnings a pre-tax gain of $3.7 million for the nine months ended September 30, 2006 and a pre-tax loss of $3.6 million for the nine months ended September 30, 2005 related to the ineffective portion of our hedges. In addition, during the nine months ended September 30, 2006, we de-designated contracts previously designated as cash-flow hedges for which the forecasted transaction originally hedged is probable of not occurring, and as a result we recognized a pre-tax loss of $10.5 million.

Our merchant energy business also enters into natural gas storage contracts under which the gas in storage qualifies for fair value hedge accounting treatment under SFAS No. 133. We recognized a $6.3 million pre-tax net gain for the quarter ended September 30, 2006 and a pre-tax net loss of $3.6 million for the quarter ended September 30, 2005 due to hedge ineffectiveness. We recognized a $7.9 million pre-tax net gain for the nine months ended September 30, 2006 and a pre-tax net loss of $3.1 million for the nine months ended September 30, 2005 due to hedge ineffectiveness. We record changes in fair value of these hedges as a component of Fuel and purchased energy expenses in our Consolidated Statements of Income.

Accounting Standards Issued

SFAS No. 157

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements.* SFAS No. 157 defines fair value, establishes a framework for measuring fair value, and expands disclosures for fair value measurements. SFAS No. 157 is effective for all fair value measurements beginning January 1, 2008. We are currently assessing the potential impact of SFAS No. 157. Based upon our initial assessment, we believe that SFAS No. 157 will affect the accounting for derivatives, which is one of our critical accounting policies, in at least two ways:

♦ We record mark-to-market energy assets net of a close-out valuation adjustment, a portion of which represents the initial contract margin when we are unable to obtain observable market price information for similar contracts. As a result, we do not recognize gains or losses in earnings at the inception of such contracts; instead, we recognize gains or losses in earnings as we realize cash flows under the contract or when observable market data becomes available. SFAS No. 157 will require us to record mark-to-market energy assets at fair value without such a valuation adjustment, resulting in the recognition of gains or losses in earnings at the inception of new mark-to-market derivative contracts executed after the effective date.

♦ We presently determine fair value for mark-to-market energy liabilities and risk management liabilities for which prices are not available from external sources by discounting the expected cash flows from the contracts using a risk-free discount rate. We do not apply a credit-spread valuation adjustment to reflect our own credit risk in determining fair value for these liabilities. SFAS No. 157 will require us to record all liabilities measured at fair value including the effect of the obligor s credit risk. As a result, we will have to apply a credit-spread adjustment in order to reflect our own credit risk in determining fair value for these liabilities, which we expect would result in a lower recorded fair value for these liabilities.

Because SFAS No. 157 applies broadly to all fair value measurements, we have not completed our assessment of its requirements, the effects of which could extend beyond the matters discussed above. In accordance with the statement s provisions, we will record the initial effects of applying SFAS No. 157 by adjusting opening retained earnings as of the required January 1, 2008 adoption date for the effect of eliminating the close-out valuation adjustment for inception gains. The remaining impacts of adoption will be reflected in earnings in 2008. The ultimate impact of applying the provisions of SFAS No. 157 could be material to our, or BGE s, financial results.

SFAS No. 158

In September 2006, the FASB issued SFAS No. 158, *Employers Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 106 and 132(R).* SFAS No. 158 requires the underfunded status of defined benefit postretirement plans to be recognized as a liability in the balance sheets and the recognition of any subsequent changes in funded status in the year in which changes occur through accumulated other comprehensive income. SFAS No. 158 is effective for us on December 31, 2006.

If our pension plan assets earn 2.2% during the fourth quarter of 2006, one quarter of our 8.75% annual return on pension assets assumption, and interest rates remain at current levels, we estimate an after-tax charge to equity of approximately $90 million would be recorded at December 31, 2006 upon the adoption of SFAS No. 158. The adoption of SFAS No. 158 will not have any impact on our, or BGE s, debt covenants.

The amounts that will ultimately be recorded upon the adoption of SFAS No. 158 will be determined by our discount rate assumption, which depends on year end interest rates, our actual 2006 return on pension assets, and other factors. As a result, the charge to equity could be materially different from our current estimate.

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FIN 48

In July 2006, the FASB issued FIN No. 48, *Accounting for Uncertainty in Income Taxes*. FIN 48 provides guidance for the recognition and measurement of an entity s uncertain tax positions through the use of a more-likely-than-not threshold. This threshold would be used to evaluate whether each tax position will be sustained based solely on its technical merits and assuming examination by a taxing authority. FIN 48 must be applied to all tax positions beginning January 1, 2007. The cumulative effect of adopting FIN 48 will be recorded in retained earnings upon adoption. We are currently assessing the potential impact of FIN 48; however, the impact could be material to our, or BGE s, financial results.

SAB 108

In September 2006, the Securities and Exchange Commission staff issued Staff Accounting Bulletin No. 108 (SAB 108), *Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements*. SAB 108 was issued in order to eliminate the diversity in practice surrounding how public companies quantify financial statement misstatements.

SAB 108 establishes an approach that requires quantification of financial statement misstatements based on the effects of the misstatements on each financial statement and the related financial statement disclosures. This model requires quantification of errors based on both an income statement and balance sheet approach. SAB 108 permits existing public companies to initially apply its provisions for fiscal periods ending after November 15, 2006.

We do not expect the implementation of SAB 108 to have any effect on our financial results.

Accounting Standards Adopted

FSP FIN 46R-6

In April 2006, the FASB issued Staff Position (FSP) FIN 46R-6, *Determining the Variability to Be Considered in Applying FASB Interpretation No. 46R.* FSP FIN 46R-6 provides that, in applying FASB Interpretation No. 46R, *Consolidation of Variable Interest Entities an Interpretation of ARB No. 51,* the reporting enterprise should consider the design of the entity, the nature of the entity s risks, and the purpose for which the entity was created. FSP FIN 46R-6 must be applied prospectively to new or modified contracts beginning July 1, 2006. The adoption of this FSP did not have a material impact on our, or BGE s, financial results.

FSP 115-1 and 124-1

In November 2005, FSP SFAS 115-1 and SFAS 124-1, *The Meaning of Other-Than-Temporary Impairment and its Application to Certain Investments*, was issued to replace the measurement and recognition criteria of EITF 03-1, *The Meaning of Other-Than-Temporary Impairment and its Application to Certain Investments*. FSP 115-1 and 124-1 references existing guidance in SFAS No. 115, *Accounting for Certain Investments in Debt and Equity Securities*, SEC Staff Accounting Bulletin No. 59, *Accounting for Noncurrent Marketable Equity Securities*, and APB No. 18, *The Equity Method of Accounting for Investments in Common Stock*. FSP 115-1 and 124-1 requires an other-than-temporary analysis to be completed each reporting period (i.e., every quarter) beginning after December 15, 2005. The adoption of this standard did not have a material impact on our, or BGE s, financial results.

Related Party Transactions BGE

Income Statement

BGE provides standard offer service to those customers that do not choose an alternate electric supplier. Our wholesale marketing and risk management operation supplies a portion of BGE s standard offer service obligation to commercial and industrial customers and provided BGE the energy and capacity required to meet all of its residential standard offer service obligations through June 30, 2006.

Our wholesale marketing and risk management operation will continue to supply a substantial portion of BGE s standard offer service obligation to residential customers through May 31, 2007, as well as a portion of BGE s standard offer service obligations from June 1, 2007 through May 31, 2009. Bidding to supply BGE s standard offer service to customers will occur from time to time through a competitive bidding process approved by the Maryland Public Service Commission.

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 September 30,		Nine Months Ended September 30,	
	2006	**2005**	**2006**	**2005**
		(In millions)		
Purchased energy	**$ 412.5**	$ 248.7	**$ 820.8**	$ 647.2

In addition, Constellation Energy charges BGE for the costs of certain corporate functions. Certain costs are directly assigned to BGE. We allocate other corporate function costs based on a total percentage of expected use by BGE. We believe this method of allocation is reasonable and approximates the cost BGE would have incurred as an unaffiliated entity.

The following table presents the costs Constellation Energy charged to BGE in each period.

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2006	**2005**	2006	**2005**
		(In millions)		
Charges to BGE	**$ 37.5**	$ 28.4	**$ 99.2**	$ 81.1

Balance Sheet

BGE participates 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. BGE had borrowed $147.3 million at September 30, 2006 and $3.2 million at December 31, 2005 under this arrangement.

BGE s Consolidated Balance Sheets include intercompany amounts related to corporate functions performed at the Constellation Energy holding company, 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, and the participation of BGE s employees in the Constellation Energy pension plan.

We believe our allocation methods are reasonable and approximate the costs that would be charged to unaffiliated entities.

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 conducts its business through various subsidiaries including a merchant energy business 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.

Our 2005 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 segments,

♦ *Strategy* section,

♦ *Business Environment* section, including how 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 require management s most difficult, subjective, or complex judgment. Our critical accounting policies include accounting for derivatives, evaluation of assets for impairment and other than temporary decline in value, and asset retirement obligations.

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, and

♦ expected sources of cash for further capital expenditures.

As you read this discussion and analysis, refer to our Consolidated Statements of Income on page 3, which present the results of our operations for the quarters and nine months ended September 30, 2006 and 2005. We analyze and explain the differences between periods in the specific line items of our Consolidated Statements of Income.

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 2006 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.

♦ 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

With the evolving regulatory environment surrounding customer choice, increasing competition, and the growth of our merchant energy business, various factors affect our financial results. We discuss these various factors in the *Forward Looking Statements* section on page 54 and in *Item 1A. Risk Factors* on page 53. We discuss our market risks in the *Market Risk* section beginning on page 50.

In this section, we discuss in more detail events which have impacted our business during the nine months ended September 30, 2006.

Regulation by the Maryland PSC

Electric Rates

As a result of the November 1999 Maryland Public Service Commission (Maryland PSC) order regarding the deregulation of electric generation in Maryland, BGE s residential electric base rates were frozen until July 2006. Subsequent orders of the Maryland PSC specified that BGE would procure the power to serve BGE residential customers beginning July 2006 via auctions to be conducted in late 2005 and early 2006. The procured power costs of these auctions resulted in an average residential customer bill increase of 72%. In a special session of the Maryland legislature in June 2006, the legislature approved Senate Bill 1 which, among other things:

♦ reconstitutes the Maryland PSC by dismissing all five of the current Maryland PSC commissioners effective June 30, 2006 and requiring that five new commissioners be selected by the Governor of Maryland from a list prepared by legislative leaders;

♦ imposes rate stabilization measures that (i) cap rate increases by BGE for residential Provider of Last Resort (POLR) service at 15% from July 1, 2006 to May 31, 2007, (ii) give residential POLR customers the option from June 1, 2007 until January 1, 2008 of paying a full market rate or choosing a short term rate stabilization plan in order to provide a smooth transition to market rates without adversely affecting the creditworthiness of BGE, and (iii) provide for full market rates for residential POLR service starting January 1, 2008;

♦ allows BGE to recover deferred costs from its customers over a period not to exceed 10 years, on terms and conditions to be determined by the Maryland PSC, including through the issuance of rate stabilization bonds that securitize the deferred costs;

♦ directs the Maryland PSC to conduct a comprehensive review of Maryland s deregulated electricity market, including the implications of requiring or allowing utilities to construct, acquire, or lease power generating facilities and alternative approaches to power procurement;

♦ directs the Maryland PSC to investigate measures to mitigate the impact of residential rate increases on BGE customers, including by investigating the prior determination of and allowances for stranded costs that occurred when BGE transferred assets to its affiliates in 2000 and by requiring the Maryland PSC to provide funds to residential customers of BGE for mitigation of BGE s rate increases, including any adjustment in favor of BGE s customers to allowances for such stranded costs;

♦ expands the authority of the Maryland PSC to review acquisitions, dispositions, and financings by public service companies operating in Maryland;

♦ requires BGE to credit residential electric rates by approximately $39 million per year for 10 years, beginning January 1, 2007, through suspending the collection of the residential return component of the administrative charge for POLR service and a credit against funds collected from BGE rate payers for the nuclear decommissioning trust for our Calvert Cliffs Nuclear Power Plant, Inc. (Calvert Cliffs); and

♦ directs Maryland s taxing authority to consider whether property tax valuation methodologies applied to power plants located in Maryland should be revised in light of the values of those properties in a restructured electric industry.

In September 2006, the Maryland Court of Appeals struck down the provisions of the new energy legislation that called for the termination and replacement of the current members of the Maryland PSC, finding such provisions to be unconstitutional. As a result, the current Maryland PSC commissioners have remained in office.

Because Senate Bill 1 requires substantial additional decisions and proceedings by the Maryland PSC and other governmental authorities to implement many of its provisions, we cannot predict the impact of the legislation on us, BGE, or the energy market in Maryland. The new legislation and its implementation through applicable regulatory proceedings could have a material adverse effect on our, or BGE s, financial results.

One or more additional parties may challenge the constitutionality of one or more other provisions of the new energy legislation. The outcome of any additional challenges and the uncertainty that could result cannot be predicted.

Cost for Decommissioning

Under the November 1999 Maryland PSC order regarding the deregulation of electric generation, BGE ratepayers must pay a total of $520 million, in 1993 dollars adjusted for inflation, to fund the decommissioning of Calvert Cliffs through fixed annual collections. The fixed annual amount was set at approximately $18.7 million through June 30, 2006. On June 28, 2006, BGE received approval from the Maryland PSC to continue annual customer collections at $18.7 million through December 31, 2016. BGE will be required to submit a filing to determine the level of customer contributions after December 31, 2016.

As discussed above, the new Maryland legislation requires BGE to credit residential electric customers the $18.7 million collected annually for 10 years beginning January 1, 2007.

Federal Regulation

Network Transmission Rates

In May 2005, the Federal Energy Regulatory Commission (FERC) issued an order accepting BGE s joint application to have network transmission rates established through a formula that tracks costs instead of through fixed rates. The formula approach became effective June 1, 2005, and the implementation of these rates did not have a material effect on our, or BGE s, financial results. The use of this formula approach was allowed by FERC to become effective subject to refund based on the outcome of a hearing before an administrative law judge. However, the various parties participating in this proceeding have arrived at a settlement resolving all issues, which was approved by FERC on April 19, 2006. The settlement did not have a material effect on our, or BGE s, financial results.

PJM Capacity Market Proposals

In April 2006, FERC issued an initial order approving PJM Interconnection s (PJM) proposal to restructure its capacity market. Such a restructuring would change how we are paid for generating plant capacity available to PJM. However, FERC found that certain elements of the proposal needed further development before FERC could issue a final order and encouraged the parties to the proceeding, including Constellation Energy, to continue to seek a negotiated resolution of the remaining issues. Subsequently, FERC directed that settlement discussions be conducted among the parties, which resulted in a settlement being filed with FERC for approval. Currently, we cannot predict the timing or outcome of any additional FERC proceedings on this matter or the possible effect on our, or BGE s, financial results.

Environmental Matters

Air Quality and Hazardous Air Emissions

In April 2006, the Healthy Air Act (HAA) was enacted into law in Maryland. The HAA establishes through two phases annual sulfur dioxide (SO_2), nitrogen oxide (NO_x), and mercury emission caps for specific coal-fired units in Maryland, including units located at three of our facilities. The first phase reduces SO_2 emissions by 74 percent in 2010 and NO_x emissions by 59 percent in 2009 (each from 2004 levels), and mercury emissions by 80 percent in 2010 (from a baseline level to be determined). The second phase reduces SO_2 emissions by 80 percent in 2013 and NO_x emissions by 66 percent in 2012 (each from 2004 levels), and mercury emissions by 90 percent in 2013 (from a baseline level to be determined).

In order to implement the requirements of the HAA, the Maryland Department of the Environment (MDE) is expected to finalize its Clean Power Rule (CPR) by the fourth quarter of 2006. The requirements of the HAA and the CPR for SO_2, NO_x, and mercury emissions are more stringent and apply sooner than those of the existing Clean Air Interstate and the Clean Air Mercury Rules. We discuss the Clean Air Interstate and the Clean Air Mercury Rules in more detail in *Item 1. Business Environmental Matters* section in our 2005 Annual Report on Form 10-K.

We have reevaluated our capital expenditure estimates provided in *Item 1. Business Environmental Matters* section in our 2005 Annual Report on Form 10-K and developed ranges of capital expenditure estimates based on bid results and our market information. This reevaluation is a result of our current understanding of what the CPR will require and pricing impacts resulting from current market demand for labor, materials, and contractors necessary to install additional emission control equipment. The upper end of our range would result in our capital expenditures increasing by approximately one-third above our previous estimate of $725 million. Our capital expenditure estimates may change further as we implement our compliance plan. As discussed in our 2005 Annual Report on Form 10-K, our estimates of capital expenditures continue to be subject to significant uncertainties.

For phase two implementation, we are currently assessing our various compliance alternatives, and although we cannot yet estimate the additional costs we may incur, such costs could be material.

In September 2006, the EPA adopted a stricter NAAQS for particulate matter. States will be required to meet the new standards by 2015, with a possible extension to 2020, depending on local conditions and the availability of controls. We are unable to determine the impact that complying with the stricter NAAQS for particulate matter will have on our financial results until the states in which our generating facilities are located adopt plans to meet the new standard.

New Source Review

In March 2006, the U.S. Court of Appeals for the District of Columbia annulled the equipment replacement rule adopted by the Environmental Protection Agency (EPA) in August 2003, which established a threshold for determining when major new source review requirements are triggered. We believe the Court decision, which was anticipated, should have minimal effect on us as it maintains the existing rules for equipment replacement. However, we anticipate that the EPA will continue to examine the existing equipment replacement rules and may again propose new rules. In addition, the U.S. Supreme Court has agreed to hear a case, not involving us, relating to the new source review requirements. We cannot predict the timing or outcome of any future EPA regulatory action or the outcome of the U.S. Supreme Court proceeding, or their possible effect on our financial results.

Global Climate Change

The HAA and the proposed CPR require that Maryland become a full participant in the Northeast Regional Greenhouse Gas Initiative (RGGI) by June 2007. RGGI is a regional cap-and-trade program initially covering carbon dioxide (CO_2) emissions from power plants with capacity greater than 25 megawatts in the affected states. The program aims to stabilize emissions at current levels beginning in 2009 and reduce regional emissions by 10 percent before 2020.

Under the program, it is expected that affected plants would participate in an auction to obtain sufficient CO_2 allowances to support the level of emissions that result from plant operations.

We continue to evaluate the potential impact of the HAA and CPR CO_2 emissions requirements and RGGI participation on our financial results; however, our compliance costs could be material.

Accounting Standards Issued and Adopted

We discuss recently issued and adopted accounting standards in the *Accounting Standards Issued* and *Accounting Standards Adopted* sections of the *Notes to Consolidated Financial Statements* beginning on page 22.

Events of 2006

Termination of Merger Agreement with FPL Group, Inc.

On October 24, 2006, Constellation Energy and FPL Group, Inc. (FPL Group) agreed to terminate the Agreement and Plan of Merger the parties had entered into on December 18, 2005. In connection with the termination of the merger agreement, Constellation Energy acquired certain development rights from FPL Group relating to a wind power project in Western Maryland.

Pursuant to the terms of the termination agreement, if Constellation Energy announces its entry into certain types of transactions on or prior to September 30, 2007, including a merger or stock sale resulting in a third party owning 35% or more of the voting securities of Constellation Energy, it will be required to pay FPL Group a fee. The fee is $425 million if a transaction is announced on or prior to June 30, 2007 and $210 million if a transaction is announced between July 1, 2007 and September 30, 2007.

Commodity Prices

During the nine months ended September 30, 2006, we continued to experience significant changes in commodity prices. This volatile commodity price environment continues to impact our results of operations and financial condition, as discussed in more detail in the following sections:

- *Financial Condition* beginning on page 45,
- *Mark-to-Market* beginning on page 35,
- *Risk Management Assets and Liabilities* on page 39,
- *Market Risk* beginning on page 50, and
- *Notes to Consolidated Financial Statements* on page 21.

Residential Electric Rates

We discuss the legislation enacted by the Maryland General Assembly in more detail in the *Regulation by the Maryland PSC* section beginning on page 25.

Gas-Fired Plants

In October 2006, we announced an agreement to sell six natural gas-fired plants. We discuss this planned sale in more detail in the *Notes to Consolidated Financial Statements* on page 11.

In October 2006, we designated these plants as assets held for sale and we reclassified the assets associated with these gas-fired plants to Assets held for sale and the liabilities to Liabilities associated with assets held for sale in our Consolidated Balance Sheets, we ceased recording depreciation expense, and discontinued hedge accounting for these facilities. The assets and liabilities associated with these gas-fired plants will be removed from our Consolidated Balance Sheets at closing.

Synthetic Fuel Facilities

Phase-Out of Tax Credits

As discussed in our 2005 Annual Report on Form 10-K, the Internal Revenue Code provides for a phase-out of synthetic fuel tax credits if average annual wellhead oil prices increase above certain levels. For 2006, we estimate the tax credit reduction would begin if the reference price exceeds approximately $54 per barrel and would be fully phased out if the reference price exceeds approximately $68 per barrel.

Based on forward market prices and volatilities as of September 30, 2006, we estimate a 42% tax credit phase-out in 2006. As a result, the amount of tax credits recognized in the first nine months of 2006 reflects the estimated 42% tax credit phase-out.

In July 2006, as a result of oil prices remaining at high levels, we decreased production at our South Carolina facility and production was idled at four facilities in which we have a minority ownership interest. In September 2006, as a result of a decrease in oil prices, we decided to resume full production at our South Carolina facility and in October 2006 production was restarted at our four facilities in which we have a minority ownership interest.

Based on forward market prices and volatilities as of October 26, 2006, we estimate a 36% tax credit phase-out in both 2006 and 2007. However, the ultimate amount of tax credits phased-out for 2006 and 2007, is subject to change based on the actual reference price and production levels for the entire year. In addition, our ability to claim synthetic fuel tax credits and the potential phase-out of these credits could be materially impacted by any future legislative changes to the Internal Revenue Code.

We actively monitor and manage our exposure to synthetic fuel tax credit phase-out as part of our ongoing hedging activities. In addition, we continue to monitor various options related to our South Carolina facility, including the suspension or cessation of synthetic fuel production depending on our expectation of the level of tax credit phase-out.

Impairment Analysis

The increase in estimated synthetic fuel tax credit phase-out during 2006 indicated there is a potential that we may not be able to recover our investments in synthetic fuel facilities. As a result of this triggering event, we performed an impairment analysis of our investment in synthetic fuel facilities.

At September 30, 2006, the book value of our investment in synthetic fuel facilities is approximately $17 million, substantially all of which is related to our South Carolina facility. We determined that an impairment had not occurred as the expected future undiscounted cash flows exceeded the book value of our investment at September 30, 2006.

We will continue to monitor the level of synthetic fuel tax credit phase-out and perform impairment analyses as new information becomes available. A future increase in synthetic fuel tax credit phase-out could result in an impairment.

Workforce Reduction Costs

During the quarter ended March 31, 2006, we incurred costs associated with a planned workforce restructuring at our R. E. Ginna Nuclear Power Plant (Ginna). In July 2006, we announced a planned workforce restructuring at our Nine Mile Point nuclear facility. We also initiated a restructuring of the workforce at our Calvert Cliffs nuclear facility during the third quarter of 2006.

In addition, during 2006, we recorded a settlement charge in our Consolidated Statements of Income for one of our qualified plans under SFAS No. 88, *Employers Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits*.

We discuss these restructurings in more detail in the *Notes to Consolidated Financial Statements* on page 12 and the settlement charge in the *Notes to Consolidated Financial Statements* on page 16.

Acquisition

During 2006, we acquired working interests in gas and oil producing fields. We discuss this acquisition in more detail in the *Notes to Consolidated Financial Statements* on page 13.Initial Public Offering of Constellation Energy Partners LLC

In June 2006, Constellation Energy Partners LLC, (CEP) a wholly owned limited liability company formed by Constellation Energy, filed a registration statement on Form S-1 with the Securities and Exchange Commission related to the potential underwritten initial public offering of CEP s common units. CEP is principally engaged in the acquisition, development and exploitation of natural gas properties. CEP s existing property is located in the Robinson s Bend Field in the Black Warrior Basin of Alabama.

Although the registration statement relating to the CEP common units has been filed with the Securities and Exchange Commission, it has not yet become effective. The common units may not be sold, nor may offers to buy be accepted, prior to the time the registration statement becomes effective. However, we currently expect to complete the offering in November 2006. This quarterly report does not constitute an offer to sell or the solicitation of any offer to buy any securities of CEP, and there will not be any sale of any such securities in any state in which such offer, solicitation, or sale would be unlawful prior to registration or qualification under the securities laws of such state.

Nine Mile Point License Extension

On October 30, 2006, we received Nuclear Regulatory Commission approval for license extension for both units at our Nine Mile Point nuclear facility. With the renewed licenses, we can continue to operate Unit 1 until 2029 and Unit 2 until 2046.

Ginna Uprate

During the fourth quarter of 2006, we completed a planned outage at our Ginna nuclear facility, which included an uprate of the plant from 498 megawatts to approximately 580 megawatts. We expect that the increase in capacity of the facility will result in higher revenues in future years due to higher generation.

Results of Operations for the Quarter and Nine Months Ended September 30, 2006 Compared with the Same Periods of 2005

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. We discuss changes in other income, fixed charges, and income taxes, as necessary, in the aggregate for all segments in the *Consolidated Nonoperating Income and Expenses* section on page 44.

Overview

Results

	Quarter Ended September 30, 2006	Quarter Ended September 30, 2005	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
	(In millions, after-tax)			
Merchant energy	**$ 284.8**	$ 141.7	**$ 400.1**	$ 282.9
Regulated electric	**42.8**	51.1	**96.3**	120.0
Regulated gas	**(7.3)**	(8.6)	**26.3**	17.3
Other nonregulated	**4.1**	(0.1)	**7.9**	0.3
Income from Continuing Operations	**324.4**	184.1	**530.6**	420.5
Income from discontinued operations		1.4	**0.9**	7.4
Net Income	**$ 324.4**	$ 185.5	**$ 531.5**	$ 427.9
Other Items Included in Operations				
Workforce reduction costs	**$ (13.1)**	$ (2.3)	**$ (14.4)**	$ (2.3)
Merger-related costs	**(2.5)**		**(10.0)**	
Non-qualifying hedges	**35.9**	(22.8)	**26.2**	(34.5)
Total Other Items	**$ 20.3**	$ (25.1)	**$ 1.8**	$ (36.8)

Quarter Ended September 30, 2006

Our total net income for the quarter ended September 30, 2006 increased $138.9 million, or $0.76 per share, compared to the same period of 2005 mostly because of the following:

♦ We had higher earnings of approximately $129 million after-tax at our merchant energy business due to higher gross margin from the Mid-Atlantic Region. We discuss this increase in gross margin in more detail in the *Mid-Atlantic Region* section on page 34.

♦ We had higher earnings of $38.6 million after-tax at our retail competitive supply operation primarily due to an increase in gross margin. We discuss our retail gross margin in more detail in the *Competitive Supply Retail* section on page 35.

♦ We had higher earnings of approximately $42 million after-tax due to higher gross margin from our wholesale competitive supply operation, including the termination and sale of an in-the-money contract. These increases were mostly offset by lower earnings of approximately $40 million after-tax due to higher operating expenses primarily because of higher labor and benefit costs due to the growth of this operation. We discuss our mark-to-market and wholesale accrual results in more detail in the *Competitive Supply* section beginning on page 35.

These increases were partially offset by the following:

♦ We had lower earnings of $10.8 million after-tax due to workforce reduction costs incurred during the third quarter of 2006 compared to the same period of 2005.

♦ We had lower earnings of $8.1 million after-tax due to higher fixed charges and lower other income. We discuss these items in more detail in the *Consolidated Nonoperating Income and Expenses* section on page 44.

♦ We had lower earnings of $7.0 million after-tax from our regulated businesses primarily due to higher operations and maintenance expenses, partially offset by higher gas revenues mostly from the favorable impact of the increase in gas base rates that was approved in December 2005. We discuss the gas base rate increase in more detail in the

Regulated Gas Business section on page 43.

Nine Months Ended September 30, 2006

Our total net income for the nine months ended September 30, 2006 increased $103.6 million, or $0.56 per share, compared to the same period of 2005 mostly because of the following:

♦ We had higher earnings of approximately $72 million after-tax due to favorable mark-to-market results, including trading activities, at our wholesale competitive supply operation. We also had higher wholesale accrual gross margin of approximately $108 million after-tax. These increases were partially offset by lower earnings of approximately $108 million after-tax due to higher operating expenses mostly because of higher labor and benefit costs due to the growth of this operation. We discuss our mark-to-market and wholesale accrual results in more detail in the *Competitive Supply* section beginning on page 35.

♦ We had higher earnings of approximately $71 million after-tax at our merchant energy business due to higher gross margin from the Mid-Atlantic Region. We discuss this increase in gross margin in more detail in the *Mid-Atlantic Region* section on page 34.

♦ We had higher earnings of $39.0 million after-tax at our retail competitive supply operation primarily due to an increase in gross margin. We discuss our retail gross margin in more detail in the *Competitive Supply Retail* section on page 35.

♦ We had higher earnings of $9.0 million after-tax from our regulated gas business primarily due to the favorable impact of the increase in gas base rates that was approved in December 2005.

These increases were partially offset by the following:

♦ We had lower earnings of $23.7 million after-tax from our regulated electric business primarily due to higher operations and maintenance expenses and lower revenues less electricity purchased for resale expenses.

♦ We had lower earnings of $20.4 million after-tax at our synthetic fuel facilities mostly due to the expected phase-out of tax credits as a result of the high price of oil. We discuss the phase-out of tax credits in more detail in the *Events of 2006* section beginning on page 28.

♦ We had lower earnings of $12.1 million after-tax due to workforce reduction costs associated with workforce restructurings at our nuclear generating facilities. We discuss these costs in more detail in the *Notes to Consolidated Financial Statements* on page 12.

♦ We had lower earnings of $10.0 million after-tax due to incurring additional merger-related costs associated with our merger with FPL Group, which has now been terminated. We discuss these costs in more detail in the *Notes to Consolidated Financial Statements* on page 12.

♦ We had lower earnings of $7.9 million after-tax due to higher fixed charges and lower other income. We discuss these items in more detail in the *Consolidated Nonoperating Income and Expenses* section on page 44.

♦ We had lower income from discontinued operations of $6.5 million.

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

Merchant Energy Business

Background

Our merchant energy business is a competitive provider of energy solutions for various customers. We discuss the impact of deregulation on our merchant energy business in *Item 1. Business Competition* section of our 2005 Annual Report on Form 10-K.

Our merchant energy business focuses on delivery of physical, customer-oriented products to producers and consumers, manages the risk and optimizes the value of our owned generation assets, and uses our portfolio management and trading capabilities both to manage risk and to deploy risk capital to generate additional returns. We continue to identify and pursue opportunities which can generate additional returns, through portfolio management and trading activities, within our business due to the significant growth in scale of our competitive supply operations.

We record merchant energy revenues and expenses in our financial results in different periods depending upon which portion of our business they affect. We discuss our revenue recognition policies in the *Critical Accounting Policies* section and *Note 1* of our 2005 Annual Report on Form 10-K. We summarize our revenue and expense recognition policies as follows:

♦ We record revenues as they are earned and fuel and purchased energy costs as they are incurred for contracts and activities subject to accrual accounting, including certain load-serving activities.

♦ Prior to the settlement of the forecasted transaction being hedged, we record changes in the fair value of contracts designated as cash-flow hedges in other comprehensive income to the extent that the hedges are effective. We record the effective portion of the changes in fair value of hedges in earnings in the period the settlement of the hedged transaction occurs. We record the ineffective portion of the changes in fair value of hedges, if any, in earnings in the period in which the change occurs.

♦ We record changes in the fair value of contracts that are subject to mark-to-market accounting in revenues or fuel and purchased energy expenses in the period in which the change occurs.

Mark-to-market accounting requires us to make estimates and assumptions using judgment in determining the fair value of certain contracts and in recording revenues from those contracts. We discuss the effects of mark-to-market accounting on our results in the *Competitive Supply Mark-to-Market* section beginning on page 35.

Our wholesale marketing and risk management operation actively transacts in energy and energy-related commodities in order to manage our portfolio of energy purchases and sales to customers through structured transactions. As part of these activities we trade energy and energy-related commodities and deploy risk capital in the management of our portfolio in order to earn additional returns. These activities are managed through daily value at risk and stop loss limits and liquidity guidelines, and may have a material impact on our financial results. We discuss the impact of our trading activities in more detail in the *Competitive Supply Mark-to-Market* section beginning on page 35 and value at risk in the *Market Risk* section beginning on page 50.

Results

	Quarter Ended September 30, 2006	Quarter Ended September 30, 2005	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
	(In millions)			
Revenues	**$ 5,049.0**	$ 4,397.2	**$ 13,121.6**	$ 10,312.4
Fuel and purchased energy expenses	**(4,056.0)**	(3,778.0)	**(10,863.3)**	(8,606.6)
Operating expenses	**(372.6)**	(273.4)	**(1,171.2)**	(931.8)
Workforce reduction costs	**(21.7)**	(3.9)	**(23.9)**	(3.9)
Merger-related costs	**(2.5)**		**(8.8)**	
Depreciation, depletion, and amortization	**(72.9)**	(74.3)	**(213.2)**	(202.6)
Accretion of asset retirement obligations	**(17.1)**	(15.8)	**(50.3)**	(46.2)
Taxes other than income taxes	**(32.6)**	(31.3)	**(94.9)**	(81.3)
Income from Operations	**$ 473.6**	$ 220.5	**$ 696.0**	$ 440.0
Income from Continuing Operations (after-tax)	**$ 284.8**	$ 141.7	**$ 400.1**	$ 282.9
Income from discontinued operations (after-tax)		(0.2)		2.9
Net Income	**$ 284.8**	$ 141.5	**$ 400.1**	$ 285.8
Other Items Included in Operations (after-tax)				
Workforce reduction costs	**$ (13.1)**	$ (2.3)	**$ (14.4)**	$ (2.3)
Merger-related costs	**(1.8)**		**(7.0)**	
Non-qualifying hedges	**35.9**	(22.8)	**26.2**	(34.5)
Total Other Items	**$ 21.0**	$ (25.1)	**$ 4.8**	$ (36.8)

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.

Revenues and Fuel and Purchased Energy Expenses

Our merchant energy business manages the revenues we realize from the sale of energy to our customers and our costs of procuring fuel and energy. As discussed on the previous page, our merchant energy business uses either accrual or mark-to-market accounting to record our revenues and expenses. Mark-to-market results reflect the net impact of amounts recorded in either revenues or fuel and purchased energy expenses to recognize changes in fair value of derivative contracts subject to mark-to-market accounting during the reporting period.

The difference between revenues and fuel and purchased energy expenses, including all direct expenses, is the gross margin of our merchant energy business, and this measure is a useful tool for assessing the profitability of our merchant energy business. Accordingly, we believe it is appropriate to discuss the operating results of our merchant energy business by analyzing the changes in gross margin between periods. In managing our portfolio, we may terminate, restructure, or acquire contracts. Such transactions are within the normal course of managing our portfolio and may materially impact the timing of our recognition of revenues, fuel and purchased energy expenses, and cash flows.

We analyze our merchant energy gross margin in the following categories because of the risk profile of each category, differences in the revenue sources, and the nature of fuel and purchased energy expenses. With the exception of a portion of our competitive supply activities that we are required to account for using the mark-to-market method of accounting, all of these activities are accounted for on an accrual basis.

♦ Mid-Atlantic Region our fossil, nuclear, and hydroelectric generating facilities and load-serving activities in the PJM region. This also includes active portfolio management of the generating assets and other physical and financial contractual arrangements, as well as other PJM competitive supply activities. In addition, due to the expiration of its power purchase agreement, beginning in June 2006, the results of our University Park generating facility are included with the Mid-Atlantic Region. University Park was previously included in Plants with Power Purchase Agreements.

♦ Plants with Power Purchase Agreements our generating facilities outside the Mid-Atlantic Region with long-term power purchase agreements, including the Nine Mile Point, Ginna, and High Desert facilities. We discuss the pending sale of our High Desert facility in the *Notes to Consolidated Financial Statements* on page 11.

- Wholesale Competitive Supply our marketing and risk management operation that provides energy products and services (including portfolio management and trading activities) primarily to distribution utilities, power generators, and other wholesale customers. We also provide global coal and upstream and downstream natural gas services.

- Retail Competitive Supply our operation that provides electric and gas energy products and services to commercial, industrial, and governmental customers.

- Other our investments in qualifying facilities and domestic power projects and our generation operations and maintenance services.

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We provide a summary of our revenues, fuel and purchased energy expenses, and gross margin as follows:

	Quarter Ended September 30, 2006	Quarter Ended September 30, 2005	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
	(Dollar amounts in millions)			
Revenues:				
Mid-Atlantic Region	**$ 1,002.2**	$ 746.7	**$ 2,119.2**	$ 1,736.9
Plants with Power Purchase Agreements	**255.0**	254.6	**639.7**	639.0
Competitive Supply				
Retail	**2,094.8**	1,990.1	**5,964.9**	4,713.6
Wholesale	**1,668.9**	1,383.0	**4,339.3**	3,180.6
Other	**28.1**	22.8	**58.5**	42.3
Total	**5,049.0**	$ 4,397.2	**$ 13,121.6**	$ 10,312.4
Fuel and purchased energy expenses:				
Mid-Atlantic Region	**$ (605.3)**	$ (563.8)	**$ (1,370.3)**	$ (1,105.0)
Plants with Power Purchase Agreements	**(16.8)**	(23.7)	**(52.2)**	(57.6)
Competitive Supply				
Retail	**(1,964.9)**	(1,938.0)	**(5,667.6)**	(4,530.9)
Wholesale	**(1,469.0)**	(1,252.5)	**(3,773.2)**	(2,913.1)
Other				
Total	**$ (4,056.0)**	$ (3,778.0)	**$ (10,863.3)**	$ (8,606.6)

	2006	% of Total	2005	% of Total	2006	% of Total	2005	% of Total
Gross Margin:								
Mid-Atlantic Region	**$ 396.9**	**40 %**	$ 182.9	30 %	**$ 748.9**	**33 %**	$ 631.9	37 %
Plants with Power Purchase Agreements	**238.2**	**24**	230.9	37	**587.5**	**26**	581.4	34
Competitive Supply								
Retail	**129.9**	**13**	52.1	8	**297.3**	**13**	182.7	11
Wholesale	**199.9**	**20**	130.5	21	**566.1**	**25**	267.5	16
Other	**28.1**	**3**	22.8	4	**58.5**	**3**	42.3	2
Total	**$ 993.0**	**100 %**	$ 619.2	100 %	**$ 2,258.3**	**100 %**	$ 1,705.8	100 %

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Mid-Atlantic Region

	Quarter Ended September 30, 2006	Quarter Ended September 30, 2005	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
		(In millions)		
Revenues	**$ 1,002.2**	$ 746.7	**$ 2,119.2**	$ 1,736.9
Fuel and purchased energy expenses	**(605.3)**	(563.8)	**(1,370.3)**	(1,105.0)
Gross margin	**$ 396.9**	$ 182.9	**$ 748.9**	$ 631.9

The increase of $214.0 million in gross margin during the quarter ended September 30, 2006 compared to the same period of 2005 is primarily due to favorable portfolio management, including the absence of higher load-serving costs, and the expiration on July 1, 2006 of fixed-price agreements established six years earlier. These increases were partially offset by lower competitive transition charge (CTC) revenues of approximately $21 million mostly due to the end of the collection of residential CTC revenues in July 2006. We discuss our CTC revenues in more detail in our 2005 Annual Report on Form 10-K.

The increase of $117.0 million in gross margin during the nine months ended September 30, 2006 compared to the same period of 2005 is primarily due to favorable portfolio management, new contracts that began in 2006, and higher revenues from the expiration of the six-year, fixed-price contracts. These increases were partially offset by the negative impact of higher variable costs, including emissions and coal, that continued to increase compared to fixed revenues under the six-year contracts.

These increases in gross margin were partially offset by:

- ♦ lower CTC revenues of approximately $42 million due to customers that completed their obligation and the continued decline in the CTC rate, and
- ♦ lower generation at Calvert Cliffs, which resulted in lower gross margin of approximately $27 million, mostly because of a longer planned 2006 refueling outage that included replacement of the reactor vessel head.

Plants with Power Purchase Agreements

	Quarter Ended September 30, 2006	Quarter Ended September 30, 2005	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
		(In millions)		
Revenues	**$ 255.0**	$ 254.6	**$ 639.7**	$ 639.0
Fuel and purchased energy expenses	**(16.8)**	(23.7)	**(52.2)**	(57.6)
Gross margin	**$ 238.2**	$ 230.9	**$ 587.5**	$ 581.4

Gross margin from our Plants with Power Purchase Agreements increased slightly for the quarter and nine months ended September 30, 2006 compared to the same periods of 2005. This was due to an increase in gross margin of approximately $17 million primarily related to our nuclear generating assets in New York mostly due to favorable pricing on the portion of the facilities sold into the wholesale market, partially offset by the absence of approximately $10 million in gross margin from the University Park facility. As discussed in the *Revenues and Fuel and Purchased Energy Expenses* section on page 32, the University Park power purchase agreement expired in May 2006. Beginning in June 2006, the results of University Park are included in the Mid-Atlantic Region.

Competitive Supply

We analyze our retail accrual, wholesale accrual, and combined mark-to-market competitive supply activities below.

Retail

	Quarter Ended September 30, 2006	Quarter Ended September 30, 2005	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
		(In millions)		

Accrual revenues	**$ 2,083.3**	$ 2,000.6	**$ 5,943.2**	$ 4,727.3
Fuel and purchased energy expenses	**(1,981.3)**	(1,938.0)	**(5,664.8)**	(4,530.9)
Retail accrual activities	**102.0**	62.6	**278.4**	196.4
Mark-to-market activities	**27.9**	(10.5)	**18.9**	(13.7)
Gross margin	**$ 129.9**	$ 52.1	**$ 297.3**	$ 182.7

The increase in gross margin of $39.4 million from our retail accrual activities during the quarter ended September 30, 2006 compared to the same period of 2005 is primarily due to higher margins mostly because of lower costs related to our load-serving obligations. We had lower costs mostly because of the absence of extreme summer

weather compared to the same period of the prior year.

The increase in gross margin of $82.0 million from our retail accrual activities during the nine months ended September 30, 2006 compared to the same period of 2005 is primarily due to:

♦ 3.6 million megawatt hours more of electricity and 41 billion cubic feet more of natural gas served to retail customers during the nine months ended September 30, 2006 compared to the same period of 2005, and

♦ higher margins mostly because of lower costs related to our load-serving obligations. We had lower costs mostly because of the absence of extreme summer weather compared to the prior year.

Wholesale

	Quarter Ended September 30, 2006	2005	Nine Months Ended September 30, 2006	2005
	(In millions)			
Accrual revenues	**$ 1,565.1**	$ 1,264.8	**$ 4,032.8**	$ 2,993.4
Fuel and purchased energy expenses	**(1,469.0)**	(1,252.5)	**(3,773.2)**	(2,913.1)
Wholesale accrual activities	**96.1**	12.3	**259.6**	80.3
Mark-to-market revenues	**103.8**	118.2	**306.5**	187.2
Gross margin	**$ 199.9**	$ 130.5	**$ 566.1**	$ 267.5

Our wholesale marketing and risk management operation had $83.8 million of higher gross margin from accrual activities during the quarter ended September 30, 2006 compared to the same period of 2005 due to:

- approximately $75 million related to new contracts entered into during 2006, higher realized gross margin associated with existing contracts, and an in-the-money contract that we terminated and sold in exchange for an upfront cash payment and the cancellation of future performance obligations. This contract termination and sale, which accounted for a majority of the increase in wholesale accrual gross margin for the quarter, allowed us to eliminate our exposure to performance risk under this contract and resulted in the realization of earnings during the quarter ended September 30, 2006 that would have been recognized over the life of the contract, and

- approximately $9 million related primarily to the growth in our coal and natural gas activities.

Our wholesale marketing and risk management operation had $179.3 million of higher gross margin from accrual activities during the nine months ended September 30, 2006 compared to the same period of 2005 due to:

- approximately $90 million primarily due to new contracts entered into during 2006 and higher realized gross margin on existing contracts,

- approximately $70 million related primarily to the growth in our coal and natural gas activities, and

- a net increase of approximately $20 million from contract restructurings related to unit contingent power purchase agreements during the nine months ended September 2006 compared to the same period of 2005. The termination and sale of these contracts has allowed us to eliminate our exposure to performance risk under these contracts.

Mark-to-Market

Mark-to-market results include net gains and losses from origination, trading, and risk management 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 2005 Annual Report on Form 10-K.

As a result of the nature of our operations and the use of mark-to-market accounting for certain activities, mark-to-market earnings will fluctuate. We cannot predict these fluctuations, but the impact on our earnings could be material. We discuss our market risk in more detail in the *Market Risk* section beginning on page 50. The primary factors that cause fluctuations in our mark-to-market results are:

- the number, size, and profitability of new transactions, including termination or restructuring of existing contracts,

- the number and size of our open derivative positions, and

- changes in the level and volatility of forward commodity prices and interest rates.

Mark-to-market results were as follows:

	Quarter Ended September 30, 2006	Quarter Ended September 30, 2005	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
	(In millions)			
Unrealized mark-to-market results				
Origination gains	**$ 3.6**	$ 3.2	**$ 9.6**	$ 12.8
Risk management and trading mark-to-market				
Unrealized changes in fair value	**128.1**	104.5	**315.8**	160.7
Changes in valuation techniques				
Reclassification of settled contracts to realized	**(95.4)**	(62.8)	**(324.3)**	(124.6)
Total risk management and trading mark-to-market	**32.7**	41.7	**(8.5)**	36.1
Total unrealized mark-to-market*	**36.3**	44.9	**1.1**	48.9
Realized mark-to-market	**95.4**	62.8	**324.3**	124.6
Total mark-to-market results	**$ 131.7**	$ 107.7	**$ 325.4**	$ 173.5

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

Origination gains arise primarily from contracts that our wholesale marketing and risk management operation 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 gains from a single transaction.

Origination gains represent the initial fair value recognized on these transactions. The recognition of origination gains is dependent on sufficient observable market data that validates the initial fair value of the contract. Liquidity and market conditions impact our ability to identify sufficient, objective market-price information to permit recognition of origination gains. As a result, while our strategy and competitive position provide the opportunity to continue to originate such transactions, the level of origination gains we are able to recognize may vary from period to period as a result of the number, size, and market-price transparency of the individual transactions executed in any period.

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 recognition of gains associated with decreases in the close-out adjustment when we are able to obtain sufficient market price information. 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.

The increase in mark-to-market results for the quarter and nine-months ended September 30, 2006, reflects our continued deployment of risk capital in order to take advantage of existing market conditions which generated significant returns and captured additional value within our trading portfolio. Additionally, our mark-to-market results included higher gains on transactions that are not trading positions. These positions are economic hedges of accrual transactions. These economic hedges receive mark-to-market accounting treatment as they are derivative contracts that are not designated for either cash-flow hedge or accrual accounting.

Mark-to-market results increased $24.0 million during the quarter ended September 30, 2006 compared to the same period of 2005 mostly because of higher unrealized changes in fair value. The increase in unrealized changes in fair value included higher pre-tax gains of approximately $97 million related to the positive impact of certain economic hedges primarily related to gas transportation and storage contracts that do not qualify for or are not designated as cash-flow hedges under Statement of Financial Accounting Standards (SFAS) No. 133, *Accounting for Derivative Instruments and Hedging Activities, as amended.* The mark-to-market accounting for these economic hedges produces a timing difference in the recognition of earnings on these transactions, as we will recognize the earnings on the accrual transactions related to these hedges in future periods. This increase in unrealized changes in fair value from these economic hedges was partially offset by lower pre-tax gains of approximately $73 million related to changes in commodity prices, price volatility, and other factors.

Mark-to-market results increased $151.9 million during the nine months ended September 30, 2006 compared to the same period of 2005 because of an increase in unrealized changes in fair value. Unrealized changes in fair value increased $155.1 million primarily due to:

♦ higher pre-tax gains of approximately $100 million related to the positive impact of certain economic hedges primarily related to gas transportation and storage contracts that do not qualify for or are not designated as cash-flow hedges, and

♦ the impact of a higher level of risk management and trading mark-to-market activities mostly due to a higher level of open positions that resulted in increased gains of approximately $80 million.

These increases were partially offset by the absence of a $24.0 million favorable impact related to changes in the close-out adjustment during the nine months ended September 30, 2006 compared to the same period of 2005. The close-out adjustments are determined by the change in open positions, new transactions where we did not have observable market price information, and existing transactions where we have now observed sufficient market price information and/or we realized cash flows since the transactions inception. We discuss the close-out adjustment in more detail in the *Critical Accounting Policies* section of our 2005 Annual Report on Form 10-K.

Mark-to-Market Energy Assets and Liabilities

Our mark-to-market energy assets and liabilities are comprised of derivative contracts subject to mark-to-market accounting and consisted of the following:

	September 30, 2006	December 31, 2005
	(In millions)	
Current Assets	**$ 889.3**	$ 1,339.2
Noncurrent Assets	**814.1**	1,089.3
Total Assets	**1,703.4**	2,428.5
Current Liabilities	**822.9**	1,348.7
Noncurrent Liabilities	**467.8**	912.3
Total Liabilities	**1,290.7**	2,261.0
Net mark-to-market energy asset	**$ 412.7**	$ 167.5

The following are the primary sources of the change in the net mark-to-market energy asset during the quarter and nine months ended September 30, 2006:

		Quarter Ended September 30, 2006		Nine Months Ended September 30, 2006
		(In millions)		
Fair value beginning of period		$ 353.7		$ 167.5
Changes in fair value recorded in earnings				
Origination gains	$ 3.6		$ 9.6	
Unrealized changes in fair value	128.1		315.8	
Changes in valuation techniques				
Reclassification of settled contracts to realized	(95.4)		(324.3)	
Total changes in fair value recorded in earnings		36.3		1.1
Changes in value of exchange-listed futures and options		41.5		173.4
Net change in premiums on options		(30.3)		58.8
Contracts acquired				
Other changes in fair value		11.5		11.9
Fair value at end of period		$ 412.7		$ 412.7

Changes in the net mark-to-market energy 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 fair value of our contracts.

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

The net mark-to-market energy asset also changed due to the following items recorded in accounts other than in our Consolidated Statements of Income:

- ♦ Changes in value of exchange-listed futures and options are adjustments to remove unrealized changes in fair value of exchange-traded contracts that are included in risk management and trading mark-to-market results. The fair value of these contracts is recorded in Accounts receivable rather than Mark-to-market energy 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 mark-to-market energy asset and premiums on options sold as a decrease in the net mark-to-market energy asset.

- ♦ Contracts acquired represents the initial fair value of acquired derivative contracts recorded in Mark-to-market energy assets and liabilities.

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The settlement terms of the net mark-to-market energy asset and sources of fair value as of September 30, 2006 are as follows:

	Settlement Term							
	2006	**2007**	**2008**	**2009**	**2010**	**2011**	**Thereafter**	**Fair Value**
	(In millions)							
Prices provided by external sources (1)	$ 12.9	$ 129.7	$ 199.2	$ 63.0	$ 27.8	$ 14.8	$ 4.9	$ 452.3
Prices based on models	(6.3)	8.4	9.3	(9.6)	(24.7)	(18.1)	1.4	(39.6)
Total net mark-to-market energy asset	$ 6.6	$ 138.1	$ 208.5	$ 53.4	$ 3.1	$ (3.3)	$ 6.3	$ 412.7

(1) Includes contracts actively quoted and contracts valued from other external sources.

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 record and 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).

Consistent with our risk management practices, we have presented the information in the table above based upon the ability to obtain reliable prices for components of the risks in our contracts from external sources rather than on a contract-by-contract basis. Thus, the portion of long-term contracts that is valued using external price sources is presented under the caption prices provided by external sources. This is consistent with how we manage our risk, and we believe it provides the best indication of the basis for the valuation of our portfolio. Since we manage our risk on a portfolio basis rather than contract-by-contract, it is not practicable to determine separately the portion of long-term contracts that is included in each valuation category. We describe the commodities, products, and delivery periods included in each valuation category in detail below.

The amounts for which fair value is determined using prices provided by external sources represent the portion of forward, swap, and option contracts for which price quotations are available through brokers or over-the-counter transactions. The term for which such price information is available varies by commodity, region, and product. The fair values included in this category are the following portions of our contracts:

♦ forward and swap purchases and sales of electricity during peak and off-peak hours for delivery terms primarily through 2009, but up to 2011, depending upon the region,

♦ options for the purchase and sale of electricity during peak hours for delivery terms through 2008, depending upon the region,

♦ forward purchases and sales of electric capacity for delivery terms primarily through 2007, but up to 2008, depending upon the region,

♦ forward and swap purchases and sales of natural gas, coal, and oil for delivery terms primarily through 2011, and

♦ options for the purchase and sale of natural gas, coal, and oil for delivery terms through 2008.

The remainder of the net mark-to-market energy asset is valued using models. The portion of contracts for which such techniques are used includes standard products for which external prices are not available and customized products that are valued using modeling techniques to determine expected future market prices, contract quantities, or both.

Modeling techniques include estimating the present value of cash flows based upon underlying contractual terms and incorporate, where appropriate, option pricing models and statistical and simulation procedures. Inputs to the models include:

♦ observable market prices,

♦ estimated market prices in the absence of quoted market prices,

♦ the risk-free market discount rate,

♦ volatility factors,

♦ estimated correlation of energy commodity prices, and

♦ expected generation profiles of specific regions.

Additionally, we incorporate counterparty-specific credit quality and factors for market price and volatility uncertainty and other risks in our valuation. The inputs and factors used to determine fair value reflect management s best estimates.

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, the majority of contracts used in the wholesale marketing and risk management operation are direct contracts between market participants and are not exchange-traded or financially settling contracts that can be readily liquidated 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.

Consistent with our risk management practices, the amounts shown in the table on the previous page as being valued using prices from external sources include the portion of long-term contracts for which we can obtain reliable prices from external sources. The remaining portions of these long-term contracts are shown in the table as being valued using models. 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 table. However, based upon the nature of the wholesale marketing and risk management operation, 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.

The fair values in the table represent expected future cash flows based on the level of forward prices and volatility factors as of September 30, 2006 and could change significantly as a result of future changes in these factors. 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.

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. However, 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.

Risk Management Assets and Liabilities

We record derivatives that qualify for designation as hedges under SFAS No. 133 in Risk management assets and liabilities in our Consolidated Balance Sheets. Our risk management assets and liabilities consisted of the following:

	September 30, 2006	December 31, 2005
	(In millions)	
Current Assets	**$ 231.2**	$ 1,244.3
Noncurrent Assets	**360.3**	626.0
Total Assets	**591.5**	1,870.3
Current Liabilities	**1,120.7**	483.5
Noncurrent Liabilities	**840.6**	1,035.5
Total Liabilities	**1,961.3**	1,519.0
Net risk management (liability) asset	**$ (1,369.8)**	$ 351.3

The decrease in our net risk management asset of $1,721.1 million since December 31, 2005 was due primarily to decreases in power prices that reduced the fair value of our cash-flow hedge positions and the settlement of cash-flow hedges during the nine months ended September 30, 2006. A decrease in the fair value of our cash-flow hedges indicates an increase in value of the accrual positions to which these hedges are related.

Other

	Quarter Ended September 30, 2006	Quarter Ended September 30, 2005	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
			(In millions)	
Revenues	**$ 28.1**	$ 22.8	**$ 58.5**	$ 42.3

Our merchant energy business holds up to a 50% voting interest in 24 operating domestic energy projects that consist of electric generation, fuel processing, or fuel handling facilities. Of these 24 projects, 17 are qualifying facilities that receive certain exemptions and pricing under the Public Utility Regulatory Policy Act of 1978 based on the facilities energy source or the use of a cogeneration process.

We believe the current market conditions for our equity-method investments that own geothermal, coal, hydroelectric, and fuel processing projects provide sufficient positive cash flows to recover our investments. We continuously monitor issues that potentially could impact future profitability of these investments, including environmental and legislative initiatives. We discuss the impact of subsidies from the State of California in more detail in the *Merchant Energy Business Other* section in our 2005 Annual Report on Form 10-K.

We discuss certain risks and uncertainties in more detail in the *Forward Looking Statements* section on page 54 and in *Item 1A. Risk Factors* section on page 53. However, should future events cause these investments to become uneconomic, our investments in these projects could become impaired under the provisions of APB No. 18.

If our strategy were to change from an intent to hold to an intent to sell for any of our equity-method investments in qualifying facilities or power projects, we would need to adjust their book value to fair value, and that adjustment could be material. If we were to sell these investments in the current market, we may have losses that could be material.

Operating Expenses

Our merchant energy business operating expenses increased $99.2 million during the quarter ended September 30, 2006 compared to the same period of 2005 mostly due to an increase at our competitive supply operations totaling $79.8 million primarily related to higher labor and benefit costs and the impact of inflation on other costs.

Our merchant energy business operating expenses increased $239.4 million during the nine months ended September 30, 2006 compared to the same period of 2005 mostly due to an increase of $220.3 million at our competitive supply operations primarily related to higher labor and benefit costs and the impact of inflation on other costs and higher costs of $11.0 million due to an outage at our High Desert facility. These increases in operating expenses were partially offset by lower expenses at our nuclear generating facilities of approximately $15 million mostly due to our productivity initiatives.

Workforce Reduction Costs

During the nine months ended September 30, 2006, our merchant energy business recognized expenses associated with our workforce reduction efforts at our nuclear facilities. We discuss the workforce reduction programs in more detail in the *Notes to Consolidated Financial Statements* on page 12.

Merger-Related Costs

We discuss costs related to the merger, which has been terminated, with FPL Group in more detail in the *Notes to Consolidated Financial Statements* on page 12.

Depreciation, Depletion, and Amortization Expense

Merchant energy depreciation, depletion, and amortization expenses increased $10.6 million during the nine months ended September 30, 2006 compared to the same period of 2005 mostly due to an increase of $10.3 million related to our working interests in gas and oil producing properties.

Taxes Other Than Income Taxes

Taxes other than income taxes increased $13.6 million during the nine months ended September 30, 2006 compared to the same period of 2005 mostly due to $8.6 million related to higher gross receipts taxes at our retail competitive supply operation and $2.9 million related to our working interests in gas producing properties.

Regulated Electric Business

Our regulated electric business is discussed in detail in *Item 1. Business Electric Business* section of our 2005 Annual Report on Form 10-K.

Results

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2006	2005	**2006**	2005
		(In millions)		
Revenues	**$ 649.9**	$ 626.8	**$ 1,652.6**	$ 1,583.4
Electricity purchased for resale expenses	**(391.1)**	(362.5)	**(933.8)**	(849.0)
Operations and maintenance expenses	**(89.3)**	(79.6)	**(258.9)**	(235.4)
Merger-related costs	**(0.6)**		**(2.3)**	
Depreciation and amortization	**(45.6)**	(46.9)	**(137.1)**	(141.1)
Taxes other than income taxes	**(34.7)**	(34.7)	**(101.5)**	(102.2)
Income from Operations	**$ 88.6**	$ 103.1	**$ 219.0**	$ 255.7
Net Income	**$ 42.8**	$ 51.1	**$ 96.3**	$ 120.0
Other Items Included in Operations (after-tax):				
Merger-related costs	**$ (0.5)**	$	**$ (2.0)**	$

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 from the regulated electric business decreased $8.3 million during the quarter ended September 30, 2006 compared to the same period of 2005 mostly because of higher operations and maintenance expenses of $5.9 million after-tax.

Net income from the regulated electric business decreased $23.7 million during the nine months ended September 30, 2006 mostly because of higher operations and maintenance expenses of $14.2 million after-tax and decreased revenue less electricity purchased for resale expenses of $9.4 million after-tax.

Electric Revenues

The changes in electric revenues in 2006 compared to 2005 were caused by:

	Quarter Ended September 30, 2006 vs. 2005		Nine Months Ended September 30, 2006 vs. 2005
		(In millions)	
Distribution volumes	$ (13.6)		$ (28.2)
Standard offer service	214.4		270.5
Rate stabilization credits	(174.4)		(174.4)
Total change in electric revenues from electric system sales	26.4		67.9
Other	(3.3)		1.3
Total change in electric revenues	$ 23.1		$ 69.2

Distribution Volumes

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

The percentage changes in our distribution volumes, by type of customer, in 2006 compared to 2005 were:

	Quarter Ended September 30, 2006 vs. 2005	Nine Months Ended September 30, 2006 vs. 2005
Residential	(6.7)%	(5.5)%
Commercial	(1.1)	(1.2)
Industrial	(12.1)	(6.3)

During the quarter and nine months ended September 30, 2006 compared to the same periods of 2005, we distributed less electricity to residential and commercial customers mostly due to milder weather and decreased usage per customer, partially offset by an increased number of customers. We distributed less electricity to industrial customers mostly due to decreased usage per customer.

Standard Offer Service

BGE provides standard offer service for customers that do not select an alternative generation supplier as discussed in *Item 1. Business Electric Regulatory Matters and Competition* section of our 2005 Annual Report on Form 10-K. We discuss the legislation enacted by the Maryland General Assembly related to the residential electric rate stabilization plan in the *Regulation by the Maryland PSC* section beginning on page 25.

Standard offer service revenues increased during the quarter and nine months ended September 30, 2006 compared to the same periods of 2005 mostly due to an increase to market prices in the standard offer service rates due to the expiration of the residential rate freeze in July 2006, partially offset by lower standard offer service volumes.

Rate Stabilization Credits

As a result of the legislation enacted by the Maryland General Assembly related to the residential electric rate stabilization plan, we are required to defer a portion of the full market rate increase during the eleven month period from July 1, 2006 until May 31, 2007 for recovery in the future. Therefore, the increase in standard offer service revenues is partially offset by rate stabilization credits in order to reduce rates for residential customers from market price to the approved increase of 15% in the enacted legislation.

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 September 30, 2006	Quarter Ended September 30, 2005	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
	(In millions)			
Actual costs	**$ 565.5**	$ 362.5	**$ 1,108.2**	$ 849.0
Deferral under rate stabilization plan	**(174.4)**		**(174.4)**	
Total electricity purchased for resale	**$ 391.1**	$ 362.5	**$ 933.8**	$ 849.0

In accordance with the rate stabilization plan, we defer the difference between our actual costs of electricity purchased for resale and what we are allowed to bill customers under legislation enacted by the Maryland General Assembly. During the quarter and nine months ended September 30, 2006, we deferred $174.4 million in electricity purchased for resale expenses. These deferred expenses, plus carrying charges, are included in Regulatory Assets (net) in our, and BGE s, Consolidated Balance Sheets. We discuss the legislation enacted by the Maryland General Assembly related to the residential electric rate stabilization plan in the *Regulation by the Maryland PSC* section beginning on page 25.

Electricity purchased for resale expenses increased $28.6 million in the quarter and $84.8 million in the nine month periods ended September 30, 2006 compared to the same periods of 2005 mostly due to increased costs to serve standard offer service customers partially offset by decreased standard offer service volumes.

Electric Operations and Maintenance Expenses

Regulated electric operations and maintenance expenses increased $9.7 million in the quarter ended September 30, 2006 compared to the same period of 2005 mostly due to $3.9 million of incremental distribution service restoration expenses associated with 2006 storms, as well as higher labor and benefit costs and the impact of inflation on other costs.

Regulated electric operations and maintenance expenses increased $23.5 million in the nine months ended September 30, 2006 compared to the same period of 2005 mostly due to higher labor and benefit costs and the impact of inflation on other costs and $10.0 million of incremental distribution service restoration expenses associated with 2006 storms.

Merger-Related Costs

We discuss costs related to the merger, which has been terminated, with FPL Group in more detail in the *Notes to Consolidated Financial Statements* on page 12.

Regulated Gas Business

Our regulated gas business is discussed in detail in *Item 1. Business Gas Business* section of our 2005 Annual Report on Form 10-K.

Results

	Quarter Ended September 30, 2006	2005	Nine Months Ended September 30, 2006	2005
		(In millions)		
Gas revenues	**$ 114.6**	$ 115.9	**$ 678.4**	$ 626.9
Gas purchased for resale expenses	**(66.4)**	(72.1)	**(448.6)**	(422.5)
Operations and maintenance expenses	**(34.6)**	(33.1)	**(105.3)**	(97.1)
Merger-related costs	**(0.2)**		**(1.0)**	
Depreciation and amortization	**(11.6)**	(11.7)	**(35.0)**	(35.5)
Taxes other than income taxes	**(7.4)**	(7.2)	**(24.9)**	(24.5)
(Loss) Income from operations	**$ (5.6)**	$ (8.2)	**$ 63.6**	$ 47.3
Net (Loss) Income	**$ (7.3)**	$ (8.6)	**$ 26.3**	$ 17.3
Other Items Included in Operations (after-tax):				
Merger-related costs	**$ (0.2)**	$	**$ (0.8)**	$

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 from the regulated gas business increased $9.0 million during the nine months ended September 30, 2006 compared to the same period of 2005 mostly due to increased revenues less gas purchased for resale expenses of $15.4 million after-tax, which was primarily due to the increase in gas base rates that was approved by the Maryland PSC in December 2005. This increase was partially offset by higher operations and maintenance expenses of $5.0 million after-tax.

Gas Revenues

The changes in gas revenues in 2006 compared to 2005 were caused by:

	Quarter Ended September 30, 2006 vs. 2005	Nine Months Ended September 30, 2006 vs. 2005
	(In millions)	
Distribution volumes	$ 0.3	$ (22.8)
Base rates	3.4	22.3
Weather normalization	(1.7)	14.8
Gas cost adjustments	(6.2)	13.2
Total change in gas revenues from gas system sales	(4.2)	27.5
Off-system sales	2.9	22.4
Other		1.6
Total change in gas revenues	$ (1.3)	$ 51.5

Distribution Volumes

The percentage changes in our distribution volumes, by type of customer, in 2006 compared to 2005 were:

	Quarter Ended September 30, 2006 vs. 2005	Nine Months Ended September 30, 2006 vs. 2005
Residential	0.5 %	(17.0)%
Commercial	(1.2)	(15.3)
Industrial	(5.7)	9.2

During the quarter ended September 30, 2006 compared to the same period in 2005, we distributed about the same amount of gas to residential customers. We distributed less gas to commercial customers mostly due to decreased usage per customer, partially offset by an increased number of customers. We distributed less gas to industrial customers due to decreased usage per customer.

During the nine months ended September 30, 2006 compared to the same period in 2005, we distributed less gas to residential and commercial customers mostly due to milder weather and decreased usage per customer, partially offset by an increased number of customers. We distributed more gas to industrial customers mostly due to increased usage per customer.

Base Rates

The Maryland PSC issued an order in December 2005 granting BGE an annual increase in its gas base rates of $35.6 million. Certain parties to the proceeding have sought judicial review and Maryland PSC rehearing of the decision. BGE will not seek review of any aspect of the order. We cannot provide assurance that a court will not reverse any aspect of the order or that it will not remand certain issues to the Maryland PSC.

Weather Normalization

The Maryland PSC allows us to record a monthly adjustment to our gas distribution revenues to eliminate the effect of abnormal weather patterns on our gas distribution volumes. This means our monthly gas base rate revenues are based on weather that is considered normal for the month and, therefore, are not affected by actual weather conditions.

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 2005 Annual Report on Form 10-K.

Gas cost adjustment revenues decreased during the quarter ended September 30, 2006 compared to the same period of 2005 mostly due to less gas sold.

Gas cost adjustment revenues increased during the nine months ended September 30, 2006 compared to the same period of 2005 because we sold gas at higher prices, partially offset by less gas sold.

Off-System Gas Sales

Off-system gas sales are low-margin direct sales of gas to wholesale suppliers of natural gas outside our service territory. 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 increased during the quarter ended September 30, 2006 compared to the same period of 2005 because we sold more gas, partially offset by lower prices.

Revenues from off-system gas sales increased during the nine months ended September 30, 2006 compared to the same period of 2005 because we sold more gas at 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 purchased for resale expenses decreased $5.7 million during the quarter ended September 30, 2006 compared to the same period of 2005 because we purchased less gas.

Gas costs increased $26.1 million during the nine months ended September 30, 2006 compared to the same period of 2005 because the gas we purchased was at higher prices, partially offset by less gas purchased.

Gas Operations and Maintenance Expenses

Regulated gas operations and maintenance expenses increased $8.2 million in the nine months ended September 30, 2006 compared to the same period of 2005 mostly due to higher labor and benefit costs and the impact of inflation on other costs.

Merger-Related Costs

We discuss costs related to the merger, which has been terminated, with FPL Group in more detail in the *Notes to Consolidated Financial Statements* on page 12.

Other Nonregulated Businesses

Results

	Quarter Ended September 30, 2006	Quarter Ended September 30, 2005	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
		(In millions)		
Revenues	**$ 45.5**	$ 49.3	**$ 169.3**	$ 144.4
Operating expense	**(31.3)**	(36.7)	**(126.6)**	(109.1)
Merger-related costs	**(0.1)**		**(0.3)**	
Depreciation and amortization	**(10.6)**	(10.4)	**(28.5)**	(28.2)
Taxes other than income taxes	**(0.2)**	(0.6)	**(1.4)**	(1.4)
Income from Operations	**$ 3.3**	$ 1.6	**$ 12.5**	$ 5.7
Income from continuing operations (after-tax)	**$ 4.1**	$ (0.1)	**$ 7.9**	$ 0.3
Income from discontinued operations (after-tax)		1.6	**0.9**	4.5
Net Income	**$ 4.1**	$ 1.5	**$ 8.8**	$ 4.8
Other Items Included in Operations (after-tax):				
Merger-related costs	**$**	$	**$ (0.2)**	$

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.

As discussed in our 2005 Annual Report on Form 10-K, we decided to sell certain non-core assets and accelerate the exit strategies on other assets that we will continue to hold and own over the next several years. While our intent is to dispose of these assets, market conditions and other events beyond our control may affect the actual sale of these assets. In addition, a future decline in the fair value of these assets could result in losses.

Consolidated Nonoperating Income and Expenses

Other Income

Our other income decreased mostly because of a lower level of interest income earned due to a lower cash balance during the quarter and nine months ended September 30, 2006 compared to the same periods of 2005.

Fixed Charges

Our fixed charges increased mostly because of a higher debt balance, including commercial paper borrowings, and higher interest rates during the quarter and nine months ended September 30, 2006 compared to the same periods of 2005.

Income Taxes

During the quarter ended September 30, 2006, our income taxes increased $89.2 million compared to the same period of 2005 mostly because of a $229.5 million increase in pre-tax income.

During the nine months ended September 30, 2006, our income taxes increased $119.2 million compared to the same period of 2005 mostly because of a $229.3 million increase in pre-tax income and a $25.4 million decrease in synthetic fuel tax credits claimed. We discuss the phase-out of synthetic fuel tax credits in more detail in the *Events of 2006* section beginning on page 28.

During the quarter and nine months ended September 30, 2006, BGE s income taxes decreased compared to the same periods of 2005 mostly because of lower pre-tax income.

Financial Condition

Cash Flows

The following table summarizes our cash flows for 2006 and 2005, excluding the impact of changes in intercompany balances.

	2006 Segment Cash Flows Nine Months Ended September 30, 2006			Consolidated Cash Flows Nine Months Ended September 30,	
	Merchant	Regulated	Other	2006	2005
			(In millions)		
Operating Activities					
Net income	$ 400.1	$ 122.6	$ 8.8	$ 531.5	$ 427.9
Non-cash adjustments to net income	284.2	73.8	22.7	380.7	542.5
Changes in working capital	(949.5)	134.1	54.0	(761.4)	130.1
Pension and postemployment benefits*				35.5	4.0
Other	(32.6)	(16.1)	25.5	(23.2)	(5.2)
Net cash (used in) provided by operating activities	(297.8)	314.4	111.0	163.1	1,099.3
Investing activities					
Investments in property, plant and equipment	(402.6)	(225.1)	(40.3)	(668.0)	(476.9)
Acquisitions, net of cash acquired	(133.5)			(133.5)	(238.1)
Investments in nuclear decommissioning trust fund securities	(275.0)			(275.0)	(258.7)
Proceeds from nuclear decommissioning trust fund securities	266.2			266.2	245.5
Sale of investments and other assets	23.2	0.5	19.8	43.5	1.9
Contract and portfolio acquisitions	(2.3)			(2.3)	(23.7)
Proceeds from sale of discontinued operations					217.6
Issuances of loans receivable	(65.4)			(65.4)	(82.8)
Other investments	28.1	10.3	(4.6)	33.8	(28.5)
Net cash used in investing activities	(561.3)	(214.3)	(25.1)	(800.7)	(643.7)
Cash flows from operating activities less cash flows from investing activities	$ (859.1)	$ 100.1	$ 85.9	(637.6)	455.6
Financing Activities*					
Net issuance (repayment) of debt				20.5	(328.4)
Proceeds from issuance of common stock				56.2	66.5
Common stock dividends paid				(195.7)	(169.1)
Proceeds from contract and portfolio acquisitions				221.3	403.3
Other				43.0	5.6
Net cash provided by (used in) financing activities				145.3	(22.1)
Net (Decrease) Increase in Cash and Cash Equivalents				$ (492.3)	$ 433.5

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

Cash Flows from Operating Activities

Cash provided by operating activities was $163.1 million in 2006 compared to $1,099.3 million in 2005. This $936.2 million decrease was primarily due to unfavorable changes in working capital and a decrease in non-cash adjustments to net income in the first nine months of 2006.

Changes in working capital had a negative impact of $761.4 million on cash flow from operations in 2006 compared to a positive impact of $130.1 million in 2005. The net decrease of $891.5 million was primarily due to the commodity price environment and increased risk management and trading activities that resulted in the following negative working capital changes during the nine months ended September 30, 2006:

♦ an increase of approximately $630 million in net cash collateral requirements, including requirements for exchange-settled transactions. This increase in cash collateral requirements was accompanied by a decrease in our letters of credit requirements, and

♦ an increase in our net mark-to-market energy asset of approximately $245 million. We discuss the changes in our net mark-to-market energy asset in more detail in the *Mark-to-Market Energy Assets and Liabilities* section on page 37.

Non-cash adjustments to net income decreased by $161.8 million in 2006 compared to 2005 primarily due to the change in deferred fuel costs of $176.8 million related mostly to the deferred recovery of electricity purchased for resale under the BGE rate stabilization plan. We discuss the rate stabilization plan in more detail in the *Notes to Consolidated Financial Statements* on page 16.

Cash Flows from Investing Activities

Cash used in investing activities was $800.7 million in 2006 compared to $643.7 million in 2005. The $157.0 million increase in cash used in 2006 compared to 2005 was primarily due to a $191.1 million increase in cash paid for investments in property, plant and equipment and the absence in 2006 of $217.6 million of proceeds from the sale of discontinued operations. This increase in cash used in investing activities was partially offset by the following:

- a $104.6 million decrease in cash paid for acquisitions,
- an increase of $62.3 million of cash provided by other investing activities,
- an increase of $41.6 million of cash provided by sales of investments,
- a $21.4 million decrease in cash paid for contract and portfolio acquisitions, and
- a decrease of $17.4 million from issuances of loans receivable.

Cash Flows from Financing Activities

Cash provided by financing activities was $145.3 million in 2006 compared to a use of $22.1 million in 2005. The increase of $167.4 million in cash provided in 2006 compared to 2005 was primarily due to a net increase in cash related to changes in short-term borrowings and long-term debt of $348.9. This increase was partially offset by a decrease of $182.0 million related to proceeds from acquired contracts and higher dividend payments in 2006 compared to 2005 of $26.6 million. We discuss the proceeds from acquired contracts below.

Contract and Portfolio Acquisitions

During 2006 and 2005, our merchant energy business acquired pre-existing energy contracts, which generated significant cash flows at the inception of the agreements. These agreements had contract prices that differed from market prices at closing, which resulted in cash payments from the counterparty at the acquisition of the contract.

We received $219.0 million during the nine months ended September 30, 2006 and $379.6 million during the same period of 2005 for these contract acquisitions. We reflect the underlying contracts on a gross basis as assets or liabilities in our Consolidated Balance Sheets depending on whether they were at above- or below-market prices at closing; therefore, we have also reflected them on a gross basis in cash flows from investing and financing activities in our Consolidated Statements of Cash Flows as follows:

Nine Months Ended September 30,	**2006**	**2005**
	(In millions)	
Financing activities proceeds from contract and portfolio acquisitions	**$ 221.3**	$ 403.3
Investing activities contract and portfolio acquisitions	**(2.3)**	(23.7)
Cash flows from contract and portfolio acquisitions	**$ 219.0**	$ 379.6

We record the proceeds we receive to acquire energy purchase and sale agreements as a financing cash inflow because it constitutes a prepayment for a portion of the market price of energy, which we will buy or sell over the term of the agreements and does not represent a cash inflow from current period operating activities. For those acquired contracts that are derivatives, we record the ongoing cash flows related to the contract as financing cash flows in accordance with SFAS No. 149.

Security Ratings

Independent credit-rating agencies rate Constellation Energy s and BGE s fixed-income securities. The ratings indicate the agencies assessment of each company s ability to pay interest, distributions, dividends, and principal on these securities. These ratings affect how much it will cost each company to sell these securities; the better the rating, the lower the cost of the securities to each company when they sell them.

The factors that credit rating agencies consider in establishing Constellation Energy s and BGE s credit ratings include, but are not limited to, cash flows, liquidity, business risk profile, regulatory and legislative climate, and the amount of debt as a component of total capitalization.

In April 2006, as a result of regulatory and legislative developments in Maryland, Standard & Poor s Rating Group, Moody s Investors Service, and Fitch Ratings reviewed our ratings and took the following actions:

♦ Fitch Ratings downgraded Constellation Energy s Senior Unsecured Debt rating from A- to BBB+, downgraded BGE s Senior Unsecured Debt ratings from A to A-, and reduced certain other credit ratings as noted in the table on the next page.

♦ Fitch Ratings changed Constellation Energy s outlook to evolving and BGE s outlook to negative.

♦ Moody s Investor Service downgraded BGE s Senior Unsecured Debt rating from A2 to A3, reduced certain other credit ratings. In July 2006, Moody s Investor Service made further changes in BGE and CEG s credit ratings and outlook as discussed below.

♦ Moody s Investor Service revised Constellation Energy s rating outlook from positive to developing.

♦ Standard & Poor s Ratings Group placed the ratings of Constellation Energy and BGE on credit watch developing from positive.

In July 2006, Moody s Investors Service completed a review of BGE s rating and took the following actions:

♦ downgraded BGE s senior unsecured debt from A3 to Baa2, and

♦ changed Constellation Energy s outlook to negative from developing.

These actions were a result of the Maryland General Assembly actions and a difficult and uncertain regulatory environment. We discuss the Maryland General Assembly actions in more detail in the *Regulation by the Maryland PSC* section beginning on page 25.

In September 2006, Standard & Poor s Ratings Group completed its annual review of Constellation Energy and BGE. Standard & Poor s Ratings Group revised its outlook for Constellation Energy s and BGE s senior unsecured debt to positive from developing. Standard & Poor s Ratings Group also raised Constellation Energy s senior unsecured debt rating to BBB+ from BBB.

In connection with the announcement of the agreement to terminate the merger with FPL Group, the rating agencies took the following actions:

♦ Standard & Poor s Ratings Group reaffirmed Constellation Energy s and BGE s credit ratings and revised its outlook on Constellation Energy and BGE to negative from positive.

♦ Moody s Investor Service reaffirmed Constellation Energy s and BGE s credit ratings and outlook.

♦ Fitch Ratings reaffirmed Constellation Energy s and BGE s credit ratings and changed its outlook on Constellation Energy to stable from evolving.

At the date of this report, our credit ratings were as follows:

	Standard & Poor s Rating Group	Moody s Investors Service	Fitch-Ratings
Constellation Energy			
Commercial Paper	A-2	P-2	F-2
Senior Unsecured Debt	BBB+ *	Baa1	BBB+ *
BGE			
Commercial Paper	A-2	P-2*	F-2*
Mortgage Bonds	A	A2*	A*
Senior Unsecured Debt	BBB+	Baa2*	A-*
Trust Preferred Securities	BBB-	Baa1*	BBB+ *
Preference Stock	BBB-	Baa2*	BBB+ *

** In 2006, these credit ratings were adjusted to this current rating.*

Available Sources of Funding

We continuously monitor our liquidity requirements and believe that our facilities and access to the capital markets provide sufficient liquidity to meet our business requirements. We discuss our available sources of funding in more detail below.

Constellation Energy

At September 30, 2006, we had $185.0 million of commercial paper outstanding, and at November 3, 2006 we had no commercial paper outstanding.

Constellation Energy has committed bank lines of credit under four credit facilities of $3.6 billion at September 30, 2006. We discuss these credit facilities in more detail in *Note 8* of our 2005 Annual Report on Form 10-K. These facilities can issue letters of credit up to $3.6 billion. Letters of credit issued under all of our facilities totaled $1.8 billion at September 30, 2006.

In October 2006, Constellation Energy activated a $1.0 billion 364-day credit agreement expiring October 23, 2007. We can borrow up to $1 billion directly from the banks or use the agreements to issue letters of credit up to $500.0 million. As a result, Constellation Energy has committed bank lines of credit under five credit facilities of $4.6 billion as of November 7, 2006.

We have executed an agreement to sell six gas-fired generating facilities. We expect the sale to close by the end of 2006 or the first quarter of 2007 and expect to receive approximately $1.5 billion in cash after tax payments. The proceeds from the sale are expected to be applied to reduce debt and invest in our business or repurchase equity. We discuss this sale in more detail in the *Notes to Consolidated Financial Statements* on page 11.

BGE

BGE currently maintains $175.0 million in annual committed credit facilities expiring May 2007 through September 2007. BGE can borrow directly from the banks or use the facilities to allow commercial paper to be issued. As of September 30, 2006, BGE had no outstanding commercial paper, which results in $175.0 million in unused credit facilities.

In October 2006, BGE issued $300.0 million of 5.90% Senior Unsecured Notes, due October 1, 2016 and $400.0 million of 6.35% Senior Unsecured Notes, due October 1, 2036. We expect that the proceeds from these issuances will be used for general corporate purposes, including refinancing the following long-term debt of BGE:

- $300.0 million of 5.25% Notes, due December 15, 2006,
- $122.0 million of 7.5% First Refunding Mortgage Bonds, due January 15, 2007, and
- $10.0 million of 6.70% Medium-term Notes, Series D, due December 1, 2006.

Pursuant to Senate Bill 1, the energy legislation adopted by the Maryland legislature, BGE is permitted to recover deferred costs associated with the residential electric rate deferral by issuing rate stabilization bonds after January 1, 2007 that securitize the deferred costs. We discuss Senate Bill 1 in more detail in the *Regulation by the Maryland PSC* section on page 25. We currently intend to issue such bonds and in November 2006, BGE filed an application with the Maryland PSC requesting approval to issue bonds in an aggregate principal amount of approximately $635 million, subject to adjustment.

Capital Resources

Our estimated annual amounts for the years 2006 and 2007 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 and redemption of preference stock.

Capital requirements for 2006 and 2007 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,
- the cost and availability of capital,
- 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 54 and *Item 1A. Risk Factors* section on page 53. We discuss legislation recently enacted by the State of Maryland and its impact on our capital expenditure estimates in the *Environmental Matters* section beginning on page 27.

Calendar Year Estimates	2006	2007
	(In millions)	
Nonregulated Capital Requirements:		
Merchant energy		
Generation plants	$ 205	$ 170
Nuclear fuel	140	140
Environmental controls	20	215
Portfolio acquisitions/investments	365	195
Technology/other	165	155
Total merchant energy capital requirements	895	875
Other nonregulated capital requirements	25	10
Total nonregulated capital requirements	920	885
Regulated Capital Requirements:		
Regulated electric	285	335
Regulated gas	65	110
Total regulated capital requirements	350	445
Total capital requirements	$ 1,270	$ 1,330

Capital Requirements

Merchant Energy Business

Our merchant energy business capital requirements consist of its continuing requirements, including expenditures for:

♦ improvements to generating plants,

♦ nuclear fuel costs,

♦ costs of complying with the Environmental Protection Agency (EPA), Maryland, and Pennsylvania environmental regulations,

♦ portfolio acquisitions, upstream gas investments, and other investments, 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.

Funding for Capital Requirements

We discuss our funding for capital requirements in our 2005 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 merchant energy business activities, and purchases of fuel and transportation to satisfy the fuel requirements of our power generating facilities.

Our total contractual payment obligations as of September 30, 2006, increased approximately $445 million during the first nine months of 2006 primarily due to an increase in fuel and transportation obligations and operating leases, partially offset by a decrease in long-term debt and purchased capacity and energy. Our fuel and transportation obligations and operating leases increased mostly due to new coal and power purchase contracts related to our merchant energy business. We detail our contractual payment obligations in the following table:

			Payments		
	2006	2007-2008	2009-2010	There-after	Total
			(In millions)		
Contractual Payment Obligations					
Long-term debt:1					
Nonregulated					
Principal	$ 5.4	$ 627.5	$ 501.5	$ 2,246.1	$ 3,380.5
Interest	54.3	364.0	313.6	1,455.5	2,187.4
Total	59.7	991.5	815.1	3,701.6	5,567.9
BGE					
Principal	310.0	416.0	11.5	589.2	1,326.7
Interest	19.3	97.5	71.2	775.1	963.1
Total	329.3	513.5	82.7	1,364.3	2,289.8
BGE preference stock				190.0	190.0
Operating leases2	49.6	340.2	171.8	552.3	1,113.9
Purchase obligations:3					
Purchased capacity and energy4	133.3	726.2	453.0	558.4	1,870.9
Fuel and transportation	730.2	2,833.3	780.5	1,068.7	5,412.7
Other	67.8	147.0	59.5	128.7	403.0
Other noncurrent liabilities:					
Postretirement and postemploy-ment benefits5	6.4	75.7	86.4	226.8	395.3
Other					
Total contractual payment obligations	$ 1,376.3	$ 5,627.4	$ 2,449.0	$ 7,790.8	$ 17,243.5

1 Amounts in long-term debt reflect the original maturity date. Investors may require us to repay $282.3 million early through put options and remarketing features. Interest on variable rate debt is included based on the September 30, 2006 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 2005 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 postretirement and postemployment benefits are for unfunded plans and reflect present value amounts consistent with the determination of the related liabilities recorded on the Consolidated Balance Sheets.

The table below presents our contingent obligations. Our contingent obligations increased approximately $840 million during the first nine months of 2006, primarily due to guarantees by the parent company for subsidiary obligations to third parties in support of the growth of our merchant energy business, partially offset by a decrease in outstanding letters of credit.

These amounts do not represent incremental consolidated Constellation Energy obligations; rather, they primarily represent parental guarantees of certain subsidiary obligations to third parties. Our calculation of the fair value of subsidiary obligations covered by the $9,734.4 million of the competitive supply guarantees was $3,114.9 million at September 30, 2006. Accordingly, if the parent company was required to fund subsidiary obligations, the total amount based on September 30, 2006 market prices would be $3,114.9 million.

			Expiration		
	2006	2007-2008	2009-2010	There-after	Total
			(In millions)		
Contingent Obligations					

Letters of credit	$ 1,236.2	$ 598.4	$	$	$ 1,834.6
Guarantees competitive supply1	3,873.6	3,254.5	342.4	2,263.9	9,734.4
Other guarantees, net2	0.6	15.2	1.4	1,264.8	1,282.0
Total contingent obligations	$ 5,110.4	$ 3,868.1	$ 343.8	$ 3,528.7	$ 12,851.0

1 While the face amount of these guarantees is $9,734.4 million, we do not expect to fund the full amount. In the event the parent was required to fulfill subsidiary obligations, our calculation of the fair value of obligations covered by these guarantees was $3,114.9 million at September 30, 2006.

2 Other guarantees in the above table are shown net of liabilities of $25.0 million recorded at September 30, 2006 in our Consolidated Balance Sheets.

Liquidity Provisions

In many cases, customers of our wholesale marketing and risk management operation rely on the creditworthiness of Constellation Energy. A decline below investment grade by Constellation Energy would negatively impact the business prospects of that operation.

We regularly review our liquidity needs to ensure that we have adequate facilities available to meet collateral requirements. This includes having liquidity available to meet margin requirements for our competitive supply operations.

We have certain agreements that contain provisions that would require additional collateral upon significant credit rating decreases in senior unsecured debt of Constellation Energy. Decreases in Constellation Energy s credit ratings would not trigger an early payment on any of our credit facilities.

Under counterparty contracts related to our wholesale marketing and risk management operation, we are obligated to post collateral if Constellation Energy s senior unsecured credit ratings declined below established contractual levels. Based on contractual provisions at September 30, 2006, we estimate that if Constellation Energy s senior unsecured debt were downgraded we would have the following additional collateral obligations:

Credit Ratings Downgraded to	Level Below Current Rating	Incremental Obligations	Cumulative Incremental Obligations
		(In millions)	
BBB/Baa2	1	$	$
BBB-/Baa3	2	542	542
Below investment grade	3	282	824

Based on market conditions and contractual obligations at the time of a downgrade, we could be required to post collateral in an amount that could exceed the amounts specified above, which could be material. We discuss our credit ratings in the *Security Ratings* section beginning on page 46 and our credit facilities in the *Available Sources of Funding* section beginning on page 47.

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 September 30, 2006, the debt to capitalization ratio as defined in the credit agreements was 49%. The failure by Constellation Energy to comply with these provisions could result in the acceleration of the maturity of the debt outstanding under these facilities, which is primarily letters of credit issued in support of our competitive supply operations. We detail our letters of credit in the *Contractual Payment Obligations and Committed Amounts* section on the previous page.

Certain credit facilities of BGE contain provisions requiring BGE to maintain a ratio of debt to capitalization equal to or less than 65%. At September 30, 2006, the debt to capitalization ratio for BGE as defined in these credit agreements was 44%. At September 30, 2006, no amount is outstanding under these facilities.

Off-Balance Sheet Arrangements

We discuss our off-balance sheet arrangements in our 2005 Annual Report on Form 10-K.

Market Risk

Commodity Risk

We measure the sensitivity of our wholesale marketing and risk management mark-to-market energy contracts to potential changes in market prices using value at risk. Value at risk represents the potential pre-tax loss in the fair value of our wholesale marketing and risk management mark-to-market energy assets and liabilities over one and ten-day holding periods. We discuss value at risk in more detail in the *Market Risk* section of our 2005 Annual Report on Form 10-K.

The table below is the value at risk associated with our wholesale marketing and risk management operation s mark-to-market energy assets and liabilities, including both trading and non-trading activities. Generally, over the last several quarters, our value at risk has increased. This is the result of the combination of market conditions, increased trading activity including the growth of our gas business, and a higher number of economic hedges of accrual positions. These economic hedges receive mark-to-market accounting treatment as they are derivative contracts that are not designated for either cash-flow hedge or accrual accounting.

During the third quarter of 2006, there was an increase in our value-at-risk primarily due to a higher number of economic hedges of accrual positions. We discuss our mark-to-market results in more detail in the *Competitive Supply* section beginning on page 35.

	Quarter Ended				
	September 30, 2005	December 31, 2005	March 31, 2006	June 30, 2006	September 30, 2006
			(In millions)		
99% Confidence Level, One-Day Holding Period					
Average	$ 6.8	$ 10.6	$ 15.4	$ 13.0	$ 18.2
High	12.3	14.5	23.5	17.5	24.2

95% Confidence Level, One-Day Holding Period					
Average*	5.2	8.0	11.7	9.9	13.9
High	9.4	11.0	17.9	13.3	18.4
95% Confidence Level, Ten-Day Holding Period					
Average	16.4	25.4	37.1	31.2	43.9
High	29.6	34.9	56.5	42.0	58.2

** For 2005, average value at risk was $4.7 million.*

The following table details our value at risk for the trading portion of our wholesale marketing and risk management mark-to-market energy assets and liabilities over a one-day holding period at a 99% confidence level for the following quarters:

			Quarter Ended		
	September 30, 2005	**December 31, 2005**	**March 31, 2006**	**June 30, 2006**	**September 30, 2006**
			(In millions)		
Average	$ 6.5	$ 9.3	$ 12.0	$ 10.8	$ 10.0
High	11.4	13.3	17.6	15.6	16.2

Due to the inherent limitations of statistical measures such as value at risk and the seasonality of changes in market prices, the value at risk calculation may not reflect the full extent of our commodity price risk exposure. Additionally, actual changes in the value of options may differ from the value at risk calculated using a linear approximation inherent in our calculation method.

As a result, actual changes in the fair value of mark-to-market energy assets and liabilities could differ from the calculated value at risk, and such changes could have a material impact on our financial results.

Wholesale Credit Risk

We actively monitor the credit portfolio of our wholesale marketing and risk management operation to attempt to reduce the impact of counterparty default. As of September 30, 2006 and December 31, 2005, the credit portfolio of our wholesale marketing and risk management operation had the following public credit ratings:

	September 30, 2006		**December 31, 2005**	
Rating				
Investment Grade[1]	**62**	**%**	53	%
Non-Investment Grade	**4**		7	
Not Rated	**34**		40	

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.

We utilize internal credit ratings to evaluate the creditworthiness of our wholesale customers, including those companies that do not have public credit ratings. The Not Rated category in the table above includes counterparties that do not have public credit ratings and include governmental entities, municipalities, cooperatives, power pools, and other load-serving entities, and marketers for which we determine creditworthiness based on internal credit ratings.

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

	September 30, 2006		**December 31, 2005**	
Investment Grade Equivalent	**82**	**%**	80	%
Non-Investment Grade	**18**		20	

A portion of our wholesale credit risk is related to transactions that are recorded in our Consolidated Balance Sheets. These transactions primarily consist of open positions from our wholesale marketing and risk management operation that are accounted for using mark-to-market accounting, as well as amounts owed by wholesale counterparties for transactions that settled but have not yet been paid. The following table highlights the credit quality and exposures related to these activities at September 30, 2006:

Rating	Total Exposure Before Credit Collateral	Credit Collateral	Net Exposure	Number of Counterparties Greater than 10% of Net Exposure	Net Exposure of Counterparties Greater than 10% of Net Exposure
			(Dollars in millions)		
Investment grade	$ 1,194	$ 125	$ 1,069		$
Split rating	14	12	2		
Non-investment grade	93	28	65		
Internally rated investment grade	472	73	399		
Internally rated non-investment grade	114	2	112		
Total	$ 1,887	$ 240	$ 1,647		$

Due to the possibility of extreme 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 electricity our wholesale marketing and risk management operation had contracted for), we could incur a loss that could have a material impact on our financial results.

Additionally, 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 mark-to-market contracts, the amount owed for settled transactions, and additional payments, if any, we would have to make to settle unrealized losses on accrual contracts.

Interest Rate Risk, Retail Credit Risk, Foreign Currency Risk, and Equity Price Risk

We discuss our exposure to interest rate risk, retail credit risk, foreign currency risk, and equity price risk in the *Market Risk* section of our 2005 Annual Report on Form 10-K.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

We discuss the following information related to our market risk:

- SFAS No. 133 hedging activities section in the *Notes to Consolidated Financial Statements* beginning on page 21,

- activities of our wholesale marketing and risk management operation in the *Merchant Energy Business* section of *Management s Discussion and Analysis* beginning on page 31,

- evaluation of commodity and credit risk in the *Market Risk* section of *Management s Discussion and Analysis* beginning on page 50, and

- changes to our business environment in the *Business Environment* section of *Management s Discussion and Analysis* beginning on page 25.

Item 4. 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 officers and principal financial officer of both Constellation Energy and BGE have 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 and BGE s disclosure controls and procedures are effective.

Changes in Internal Control over Financial Reporting

During the quarter ended September 30, 2006, 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 1A. Risk Factors

The risk factors included in our 2005 Annual Report on Form 10-K have not materially changed except as set forth below. You should consider carefully the following risks, along with the risks described under Item 1A. Risk Factors in our 2005 Annual Report on Form 10-K. The risks and uncertainties described herein and in our 2005 Annual Report on Form 10-K are not the only ones that may affect us. Additional risks and uncertainties also may adversely affect our business and operations including those discussed in Item 2. Management s Discussion and Analysis. If any of the events described actually occur, our business and financial results could be materially adversely affected.

Energy and environmental legislation recently adopted in Maryland may be implemented in a manner that could materially adversely affect our business prospects and financial results.

The recent adoption in Maryland of energy legislation was a response to anticipated increases in residential electric rates. The legislation, among other things, introduces a temporary cap on rate increases and requires the Maryland PSC to evaluate the status of Maryland s deregulated electricity market, including the implications of requiring or allowing utilities to construct or acquire generating facilities, to re-evaluate the allowance for stranded costs under the Maryland Electric Customer Choice and Competition Act of 1999 and to consider adjustments to power plant property taxes. Because the energy legislation is still in the process of being implemented, and in light of recently decided and still pending court cases involving the legislation, we do not know the impact such legislation will have on our business or financial results.

In addition, Maryland has adopted the Healthy Air Act, which will mandate, among other things, more rapid emission reductions by Maryland power generation facilities (including those owned and operated by us) than are required by current federal laws and regulations. This legislation will be implemented through the Clean Power Rule, which we expect to be finalized in the fourth quarter of 2006.

If either the energy or environmental legislation is implemented in a manner adverse to us, our financial results could be negatively impacted.

Item 2. Unregistered Sales of Equity Securities and Use of Proceed

The following table presents shares surrendered by employees to satisfy tax withholding obligations on vested restricted stock.

Period	Total Number of Shares Purchased	Average Price Paid for Shares	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares that May Yet Be Purchased Under the Plans and Programs
July 1 July 31, 2006	575	$ 55.90		
August 1 August 31, 2006	832	57.87		
September 1 - September 30, 2006	1,391	59.54		
Total	2,798	$ 58.30		

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 disclo 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,

♦ the liquidity and competitiveness of wholesale markets for energy commodities,

♦ the effect of weather and general economic and business conditions on energy supply, demand, and prices,

♦ the ability to attract and retain customers in our competitive supply activities 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 on a transitional basis in those markets,

♦ uncertainties associated with estimating natural gas reserves, developing properties, and extracting natural gas,

♦ regulatory or legislative developments that affect deregulation, transmission or distribution rates and revenues, demand for energy, or increases in costs, including costs related to nuclear power plants, safety, or environmental compliance,

♦ the inability of Baltimore Gas and Electric Company (BGE) to recover all its costs associated with providing electric residential customer service,

♦ the conditions of the capital markets, interest rates, availability of credit, liquidity, and general economic conditions, as well as Constellation Energy Group s (Constellation Energy) and BGE s 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,

♦ operational factors affecting commercial operations of our generating facilities (including nuclear facilities) and BGE s transmission and distribution facilities, including catastrophic 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, liabilities associated with catastrophic events, and other events beyond our control,

♦ the actual outcome of uncertainties associated with assumptions and estimates using judgment when 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,

- 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 and complete acquisitions and sales of businesses and assets, and

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

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 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 assume responsibility to update these forward looking statements.

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Item 6. Exhibits

Exhibit No. 2(a)	Purchase and Sale Agreement by and between Constellation Power, Inc. and TPF Generation Holdings, LLC dated as of October 10, 2006.
Exhibit No. 2(b)*	Termination and Release Agreement, dated October 24, 2006, by and among Constellation Energy Group, Inc., FPL Group, Inc. and CF Merger Corporation (Designated as Exhibit 2.1 to the Current Report on Form 8-K dated October 25, 2006, File Nos. 1-12869 and 1-1910.)
Exhibit No. 3(a)	Bylaws of Constellation Energy Group, Inc. as amended to October 20, 2006.
Exhibit No. 4(a)	First Supplemental Indenture between Baltimore Gas and Electric Company and Deutsche Bank Trust Company Americas, as trustee, dated as of October 13, 2006.
Exhibit No. 4(b)	Registration Rights Agreement dated October 13, 2006 among Baltimore Gas and Electric Company and the parties named therein relating to 5.90% Notes due 2016.
Exhibit No. 4(c)	Registration Rights Agreement dated October 13, 2006 among Baltimore Gas and Electric Company and the parties named therein relating to 6.35% Notes due 2036.
Exhibit No. 10(a)	Constellation Energy Group, Inc. Deferred Compensation Plan for Non-Employee Directors, as amended and restated.
Exhibit No. 10(b)	Constellation Energy Group, Inc. Executive Long-Term Incentive Plan, as amended and restated.
Exhibit No. 10(c)	Constellation Energy Group, Inc. 2002 Senior Management Long-Term Incentive Plan, as amended and restated.
Exhibit No. 10(d)	Constellation Energy Group, Inc. Management Long-Term Incentive Plan, as amended and restated.
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. as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
Exhibit No. 31(b)	Certification of Executive Vice President, Chief Financial Officer, and Chief Administrative Officer of Constellation Energy Group, Inc. as adopted 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 as adopted 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 as adopted 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 Executive Vice President, Chief Financial Officer, and Chief Administrative 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.

* Incorporated by Reference.

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)

BALTIMORE GAS AND ELECTRIC COMPANY
(Registrant)

Date: November 9, 2006

/s/ E. Follin Smith
E. Follin Smith,
Executive Vice President of Constellation Energy Group, Inc. and Senior Vice President of Baltimore Gas and Electric Company, and as Principal Financial Officer of each Registrant