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.*

***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.*

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***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 |

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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

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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.



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| | 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, 2006 | Quarter Ended September 30, 2005 | Nine Months Ended September 30, 2006 | Nine Months Ended September 30, 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, 2006 | Quarter Ended September 30, 2005 | Nine Months Ended September 30, 2006 | Nine Months Ended September 30, 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, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | **2006** | 2005 | **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.

**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, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | **2006** | **2005** | **2006** | **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 ) |

| | | **% of Total** | | **% of Total** | | **% of Total** | | **% 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 | | | | |