ROYAL BANK OF CANADA
Form 424B2
March 14, 2018

RBC Capital Markets®	Filed Pursuant to Rule 424(b)(2) Registration Statement No. 333-208507

Pricing Supplement Dated March 12, 2018 To the Product Prospectus Supplement ERN-EI-1, dated January 12, 2016, Prospectus Supplement, dated January 8, 2016, and Prospectus, dated January 8, 2016	$1,150,000 Absolute Return Buffered Enhanced Return Notes Linked to a Basket of Equity Indices, Due September 15, 2023 Royal Bank of Canada

Royal Bank of Canada is offering the Absolute Return Buffered Enhanced Return Notes (the "Notes") linked to the performance of an equally weighted basket of equity indices (the "Basket") comprised of the S&P 500® Index (50%), and the Dow Jones Industrial Average® (50%).

The CUSIP number for the Notes is 78013XHK7. If the Percentage Change of the Basket is greater than 0%, the Notes provide a positive return based on 105% of that Percentage Change. If the Percentage Change of the Basket is negative but greater than or equal to -20%, the investor will receive a one-for-one positive return equal to the absolute value of the Percentage Change. However, if the Percentage Change of the Basket is less than -20%, you will lose 1% of the principal amount for each 1% decrease in the value of the Basket of more than 20%, and you may lose up to 80% of your initial investment. Any payments on the Notes are subject to our credit risk.

Issue Date: March 15, 2018

Maturity Date: September 15, 2023

The Notes do not pay interest. The Notes will not be listed on any securities exchange.

Investing in the Notes involves a number of risks. See "Risk Factors" beginning on page S-1 of the prospectus supplement dated January 8, 2016, "Additional Risk Factors Specific to the Notes" beginning on page PS-4 of the product prospectus supplement dated January 12, 2016, and "Selected Risk Considerations" beginning on page P-6 of this pricing supplement.

The Notes will not constitute deposits insured by the Canada Deposit Insurance Corporation, the U.S. Federal Deposit Insurance Corporation or any other Canadian or U.S. government agency or instrumentality.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or determined that this pricing supplement is truthful or complete. Any representation to the contrary is a criminal offense.

	Per Note	Total
Price to public(1)	100.00%	$1,150,000.00
Underwriting discounts and commissions(1)	2.15%	$24,725.00
Proceeds to Royal Bank of Canada	97.85%	$1,125,275.00

(1) Certain dealers who purchase the Notes for sale to certain fee-based advisory accounts may forego some or all of their underwriting discount or selling concessions. The public offering price for investors purchasing the Notes in these accounts may be between $978.50 and $1,000 per $1,000 in principal amount.

The initial estimated value of the Notes as of the date of this pricing supplement is $962.12 per $1,000 in principal amount, which is less than the price to public. The actual value of the Notes at any time will reflect many factors, cannot be predicted with accuracy, and may be less than this amount. We describe our determination of the initial estimated value in more detail below.

RBC Capital Markets, LLC, which we refer to as RBCCM, acting as agent for Royal Bank of Canada, received a commission of $21.50 per $1,000 in principal amount of the Notes and used a portion of that commission to allow selling concessions to other dealers of up to $21.50 per $1,000 in principal amount of the Notes. The other dealers may forgo, in their sole discretion, some or all of their selling concessions. See "Supplemental Plan of Distribution (Conflicts of Interest)" below.

RBC Capital Markets, LLC

Absolute Return Buffered Enhanced Return
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SUMMARY

The information in this "Summary" section is qualified by the more detailed information set forth in this pricing supplement, the product prospectus supplement, the prospectus supplement, and the prospectus.

Issuer:	Royal Bank of Canada ("Royal Bank")
Issue:	Senior Global Medium-Term Notes, Series G
Underwriter:	RBC Capital Markets, LLC ("RBCCM")
Reference Asset:	The Notes are linked to the level of an equally weighted basket (the "Basket") of two equity indices (each, a "Basket Component," collectively, the "Basket Components"). The Basket Components and their respective Component Weights are indicated in the table below.
Currency:	U.S. Dollars
Denominations:	$1,000 and minimum denominations of $1,000 in excess thereof
Pricing Date:	March 12, 2018
Issue Date:	March 15, 2018
CUSIP:	78013XHK7
Valuation Date:	September 12, 2023
Payment at Maturity (if held to maturity):	If the Percentage Change is positive, then the investor will receive a return equal to the principal amount multiplied by the product of the Percentage Change and the Leverage Factor. If the Percentage Change is negative but greater than or equal to -20%, then the investor will receive a cash payment equal to absolute value of the Percentage Change, calculated as follows: $1,000 + [-1 x ($1,000 x Percentage Change)] If the Percentage Change is less than -20% (that is, the Percentage Change is between -20.01% and -100%), then the investor will receive a cash payment equal to: Principal Amount + [Principal Amount x (Percentage Change + Buffer Amount)] In this case, the payment on the Notes will be less than the principal amount, and you will lose up to 80% of the principal amount.
Percentage Change:	The Percentage Change, expressed as a percentage and rounded to two decimal places, will be equal to the sum of the Weighted Component Change for each Basket Component. The Weighted Component Change for each Basket Component will be determined as follows:
Leverage Factor:	105%
Initial Level:	With respect to each Basket Component, its closing level on the Pricing Date, as provided in the table below.
Final Level:	With respect to each Basket Component, its closing level on the Valuation Date.
Buffer Amount:	20%

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The Basket:	Basket Component	Bloomberg Ticker	Component Weight	Initial Level*
	S&P 500® Index (the "SPX")	SPX	50%	2,783.02
	Dow Jones Industrial Average® (the "INDU")	INDU	50%	25,178.61
	* The Initial Level for each Basket Component was its closing level on the Pricing Date.			
Maturity Date:	September 15, 2023, subject to extension for market and other disruptions, as described in the product prospectus supplement dated January 12, 2016.			
Term:	Approximately 5.5 years			
Principal at Risk:	The Notes are NOT principal protected. You will lose up to 80% of your principal amount at maturity if the Percentage Change of the Basket is less than -20%.			
Calculation Agent:	RBCCM			
U.S. Tax Treatment:	By purchasing a Note, each holder agrees (in the absence of a change in law, an administrative determination or a judicial ruling to the contrary) to treat the Note as a pre-paid cash-settled derivative contract in respect of the Basket for U.S. federal income tax purposes. However, the U.S. federal income tax consequences of your investment in the Notes are uncertain and the Internal Revenue Service could assert that the Notes should be taxed in a manner that is different from that described in the preceding sentence. Please see "Supplemental Discussion of U.S. Federal Income Tax Consequences" below and the discussion (including the opinion of our counsel Morrison & Foerster LLP) in the product prospectus supplement dated January 12, 2016 under "Supplemental Discussion of U.S. Federal Income Tax Consequences," which applies to the Notes.			
Secondary Market:	RBCCM (or one of its affiliates), though not obligated to do so, may maintain a secondary market in the Notes after the Issue Date. The amount that you may receive upon sale of your Notes prior to maturity may be less than the principal amount of your Notes.			
Listing:	The Notes will not be listed on any securities exchange.			
Clearance and Settlement:	DTC global (including through its indirect participants Euroclear and Clearstream, Luxembourg as described under "Description of Debt Securities—Ownership and Book-Entry Issuance" in the prospectus dated January 8, 2016).			
Terms Incorporated in the Master Note:	All of the terms appearing above the item captioned "Secondary Market" on pages P-2 and P-3 of this pricing supplement and the terms appearing under the caption "General Terms of the Notes" in the product prospectus supplement dated January 12, 2016, as modified by this pricing supplement.			

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ADDITIONAL TERMS OF YOUR NOTES

You should read this pricing supplement together with the prospectus dated January 8, 2016, as supplemented by the prospectus supplement dated January 8, 2016 and the product prospectus supplement dated January 12, 2016, relating to our Senior Global Medium-Term Notes, Series G, of which these Notes are a part. Capitalized terms used but not defined in this pricing supplement will have the meanings given to them in the product prospectus supplement. In the event of any conflict, this pricing supplement will control. The Notes vary from the terms described in the product prospectus supplement in several important ways. You should read this pricing supplement carefully.

This pricing supplement, together with the documents listed below, contains the terms of the Notes and supersedes all prior or contemporaneous oral statements as well as any other written materials including preliminary or indicative pricing terms, correspondence, trade ideas, structures for implementation, sample structures, brochures or other educational materials of ours. You should carefully consider, among other things, the matters set forth in "Risk Factors" in the prospectus supplement dated January 8, 2016, "Additional Risk Factors Specific to the Notes" in the product prospectus supplement dated January 12, 2016 and "Selected Risk Considerations" in this pricing supplement, as the Notes involve risks not associated with conventional debt securities. We urge you to consult your investment, legal, tax, accounting and other advisors before you invest in the Notes. You may access these documents on the Securities and Exchange Commission (the "SEC") website at www.sec.gov as follows (or if that address has changed, by reviewing our filings for the relevant date on the SEC website):

Prospectus dated January 8, 2016:
http://www.sec.gov/Archives/edgar/data/1000275/000121465916008810/j18160424b3.htm

Prospectus Supplement dated January 8, 2016:
https://www.sec.gov/Archives/edgar/data/1000275/000121465916008811/p14150424b3.htm

Product Prospectus Supplement ERN-EI-1 dated January 12, 2016:
https://www.sec.gov/Archives/edgar/data/1000275/000114036116047560/form424b5.htm

Our Central Index Key, or CIK, on the SEC website is 1000275. As used in this pricing supplement, "we," "us," or "our" refers to Royal Bank of Canada.

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HYPOTHETICAL RETURNS

The examples set out below are included for illustration purposes only. The hypothetical Percentage Changes of the Basket used to illustrate the calculation of the Payment at Maturity are not estimates or forecasts of the level of any Basket Component on any trading day prior to the Maturity Date. All examples are based on the Leverage Factor of 105%, the Buffer Amount of 20% and assume that a holder purchased Notes with an aggregate principal amount of $1,000 and that no market disruption event occurs on the Valuation Date.

Example 1—Calculation of the Payment at Maturity where the Percentage Change is positive.

Percentage Change:	10%
Payment at Maturity:	$1,000 + ($1,000 x 10% x 105%) = $1,000 + ($100 x 105%) = $1,105

On a $1,000 investment, a 10% Percentage Change results in a Payment at Maturity of $1,105, a 10.50% return on the Notes.

Example 2— Calculation of the Payment at Maturity where the Percentage Change is negative (but greater than or equal to -20%).

Percentage Change:	-15%
Payment at Maturity:	On a $1,000 investment, a -15% Percentage Change results in a Payment at Maturity of $1,150.00, a 15% return on the Notes.

Example 3—Calculation of the Payment at Maturity where the Percentage Change is less than -20%.

Percentage Change:	-40%
Payment at Maturity:	$1,000 + [$1,000 x (-40% + 20%)] = $1,000 - $200 = $800

On a $1,000 investment, a -40% Percentage Change results in a Payment at Maturity of $800,
a -20% return on the Notes.

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SELECTED RISK CONSIDERATIONS

An investment in the Notes involves significant risks. Investing in the Notes is not equivalent to investing directly in any of the securities included in any Basket Component. These risks are explained in more detail in the section "Additional Risk Factors Specific to the Notes," beginning on page PS-4 of the product prospectus supplement. In addition to the risks described in the prospectus supplement and the product prospectus supplement, you should consider the following:

- Principal at Risk - Investors in the Notes will lose up to 80% of their principal amount if the Percentage Change of the Basket is less than -20%. In such a case, you will lose 1% of the principal amount of your Notes for each 1% that the value of the Basket decreases by more than the Buffer Amount from the Pricing Date to the Valuation Date.
- The Notes Do Not Pay Interest and Your Return May Be Lower than the Return on a Conventional Debt Security of Comparable Maturity - There will be no periodic interest payments on the Notes as there would be on a conventional fixed-rate or floating-rate debt security having the same maturity. The return that you will receive on the Notes, which could be negative, may be less than the return you could earn on other investments. Even if your return is positive, your return may be less than the return you would earn if you bought a conventional senior interest bearing debt security of Royal Bank.
- Payments on the Notes Are Subject to Our Credit Risk, and Changes in Our Credit Ratings Are Expected to Affect the Market Value of the Notes - The Notes are Royal Bank's senior unsecured debt securities. As a result, your receipt of the amount due on the Maturity Date is dependent upon Royal Bank's ability to repay its obligations at that time. This will be the case even if the value of the Basket increases after the Pricing Date. No assurance can be given as to what our financial condition will be at the maturity of the Notes.
- There May Not Be an Active Trading Market for the Notes—Sales in the Secondary Market May Result in Significant Losses - There may be little or no secondary market for the Notes. The Notes will not be listed on any securities exchange. RBCCM and other affiliates of Royal Bank may make a market for the Notes; however, they are not required to do so. RBCCM or any other affiliate of Royal Bank may stop any market-making activities at any time. Even if a secondary market for the Notes develops, it may not provide significant liquidity or trade at prices advantageous to you. We expect that transaction costs in any secondary market would be high. As a result, the difference between bid and asked prices for your Notes in any secondary market could be substantial.
- You Will Not Have Any Rights to the Securities Included in the Basket Components - As a holder of the Notes, you will not have voting rights or rights to receive cash dividends or other distributions or other rights that holders of securities included in a Basket Component would have. The Final Levels of the Basket Components will not reflect any dividends paid on the securities included in the Basket Components, and accordingly, any positive return on the Notes may be less than the potential positive return on those securities.
- The Initial Estimated Value of the Notes Is Less than the Price to the Public - The initial estimated value set forth on the cover page of this pricing supplement does not represent a minimum price at which we, RBCCM or any of our affiliates would be willing to purchase the Notes in any secondary market (if any exists) at any time. If you attempt to sell the Notes prior to maturity, their market value may be lower than the price you paid for them and the initial estimated value. This is due to, among other things, changes in the value of the Basket, the borrowing rate we pay to issue securities of this kind, and the inclusion in the price to the public of the underwriting discount and the estimated costs relating to our hedging of the Notes. These factors, together with various credit, market and economic factors over the term of the Notes, are expected to reduce the price at which you may be able to sell the Notes in any secondary market and will affect the value of the Notes in complex and unpredictable ways. Assuming no change in market conditions or any other relevant factors, the price, if any, at which you may be able to sell your Notes prior to maturity may be less than your original purchase price, as any such sale price would not be expected to include the underwriting discount and the hedging costs relating to the Notes. In addition to bid-ask spreads, the value of the Notes determined for any secondary market price is expected to be based on the secondary rate rather than the

internal funding rate used to price the Notes and determine the initial estimated value. As a result, the secondary price will be less than if the internal funding rate was used. The Notes are not designed to be short-term trading instruments. Accordingly, you should be able and willing to hold your Notes to maturity.

- The Initial Estimated Value of the Notes Is an Estimate Only, Calculated as of the Time the Terms of the Notes Were Set - The initial estimated value of the Notes is based on the value of our obligation to make the payments on the Notes, together with the mid-market value of the derivative embedded in the terms of the Notes. See "Structuring the Notes" below. Our estimate is based on a variety of assumptions, including our credit spreads, expectations as to dividends, interest rates and volatility, and the expected term of the Notes. These assumptions are based on certain forecasts about future events, which may prove to be incorrect. Other entities may value the Notes or similar securities at a price that is significantly different than we do.

The value of the Notes at any time after the Pricing Date will vary based on many factors, including changes in market conditions, and cannot be predicted with accuracy. As a result, the actual value you would receive if you sold the Notes in any secondary market, if any, should be expected to differ materially from the initial estimated value of your Notes.

- Changes in the Level of One Basket Component May Be Offset by Changes in the Level of the Other Basket Component - A change in the level of one Basket Component may not correlate with changes in the levels of the other Basket Component. The level of one Basket Component may increase, while the level of the other Basket Component may not increase as much, or may even decrease. Therefore, in determining the value of the Basket as of any time, increases in the level of one Basket Component may be moderated, or wholly offset, by lesser increases or decreases in the level of the other Basket Component.
- Market Disruption Events and Adjustments - The Payment at Maturity and the Valuation Date are subject to adjustment as described in the product prospectus supplement. For a description of what constitutes a market disruption event as well as the consequences of that market disruption event, see "General Terms of the Notes—Market Disruption Events" in the product prospectus supplement.

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INFORMATION REGARDING THE REFERENCE INDICES

All disclosures contained in this pricing supplement regarding the Basket Components, including, without limitation, their make-up, method of calculation, and changes in their components, have been derived from publicly available sources prepared by the sponsors of the Basket Components. Such information reflects the policies of, and is subject to change by the sponsors. The sponsors have no obligation to continue to publish, and may discontinue publication of, the Basket Components. The consequences of the index sponsors discontinuing publication of the Basket Components are discussed in the section of the product prospectus supplement entitled "General Terms of the Notes—Unavailability of the Level of the Reference Asset." Neither we nor RBCCM accepts any responsibility for the calculation, maintenance or publication of any Basket Component or any successor index.

S&P 500® Index ("SPX")

The SPX is intended to provide an indication of the pattern of common stock price movement. The calculation of the level of the SPX is based on the relative value of the aggregate market value of the common stocks of 500 companies as of a particular time compared to the aggregate average market value of the common stocks of 500 similar companies during the base period of the years 1941 through 1943.

S&P Dow Jones Indices LLC ("S&P") calculates the SPX by reference to the prices of the constituent stocks of the SPX without taking account of the value of dividends paid on those stocks. As a result, the return on the Notes will not reflect the return you would realize if you actually owned the SPX constituent stocks and received the dividends paid on those stocks.

Effective with the September 2015 rebalance, consolidated share class lines will no longer be included in the SPX. Each share class line will be subject to public float and liquidity criteria individually, but the company's total market capitalization will be used to evaluate each share class line. This may result in one listed share class line of a company being included in the SPX while a second listed share class line of the same company is excluded.

Computation of the SPX

While S&P currently employs the following methodology to calculate the SPX, no assurance can be given that S&P will not modify or change this methodology in a manner that may affect the Payment at Maturity.

Historically, the market value of any component stock of the SPX was calculated as the product of the market price per share and the number of then outstanding shares of such component stock. In March 2005, S&P began shifting the SPX halfway from a market capitalization weighted formula to a float-adjusted formula, before moving the SPX to full float adjustment on September 16, 2005. S&P's criteria for selecting stocks for the SPX did not change with the shift to float adjustment. However, the adjustment affects each company's weight in the SPX.

Under float adjustment, the share counts used in calculating the SPX reflect only those shares that are available to investors, not all of a company's outstanding shares. Float adjustment excludes shares that are closely held by control groups, other publicly traded companies or government agencies.

In September 2012, all shareholdings representing more than 5% of a stock's outstanding shares, other than holdings by "block owners," were removed from the float for purposes of calculating the SPX. Generally, these "control holders" will include officers and directors, private equity, venture capital and special equity firms, other publicly traded companies that hold shares for control, strategic partners, holders of restricted shares, ESOPs, employee and family trusts, foundations associated with the company, holders of unlisted share classes of stock, government entities at all levels (other than government retirement/pension funds) and any individual person who controls a 5% or greater stake in a company as reported in regulatory filings. However, holdings by block owners, such as depositary banks, pension funds, mutual funds and ETF providers, 401(k) plans of the company, government retirement/pension funds, investment funds of insurance companies, asset managers and investment funds, independent foundations and savings and investment plans, will ordinarily be considered part of the float.

Treasury stock, stock options, equity participation units, warrants, preferred stock, convertible stock, and rights are not part of the float. Shares held in a trust to allow investors in countries outside the country of domicile, such as depositary shares and Canadian exchangeable shares are normally part of the float unless those shares form a control block.

For each stock, an investable weight factor (“IWF”) is calculated by dividing the available float shares by the total shares outstanding. Available float shares are defined as the total shares outstanding less shares held by control holders. This calculation is subject to a 5% minimum threshold for control blocks. For example, if a company’s officers and directors hold 3% of the company’s shares, and no other control group holds 5% of the company's shares, S&P would assign that company an IWF of 1.00, as no control group meets the 5% threshold. However, if a company's officers and directors hold 3% of the company's shares and another control group holds 20% of the company's shares, S&P would assign an IWF of 0.77, reflecting the fact that 23% of the company's outstanding shares are considered to be held for control. As of July 31, 2017, companies with multiple share class lines are no longer eligible for inclusion in the SPX. Constituents of the SPX prior to July 31, 2017 with multiple share class lines will be grandfathered in and continue to be included in the SPX. If a constituent company of the SPX reorganizes into a multiple share class line structure, that company will remain in the SPX at the discretion of the S&P Index Committee in order to minimize turnover

The SPX is calculated using a base-weighted aggregate methodology. The level of the SPX reflects the total market value of all 500 component stocks relative to the base period of the years 1941 through 1943. An indexed number is used to represent the results of this calculation in order to make the level easier to use and track over time. The actual total market value of the component stocks during the base period of the years 1941 through 1943 has been set to an indexed level of 10. This is often indicated by the notation 1941-43 = 10. In practice, the daily calculation of the SPX is computed by dividing the total market value of the component stocks by the "index divisor." By itself, the index divisor is an arbitrary number. However, in the context of the calculation of the SPX, it serves as a link to the original base period level of the SPX. The index divisor keeps the SPX comparable over time and is the manipulation point for all adjustments to the SPX, which is index maintenance.

Index Maintenance

Index maintenance includes monitoring and completing the adjustments for company additions and deletions, share changes, stock splits, stock dividends, and stock price adjustments due to company restructuring or spinoffs. Some corporate actions, such as stock splits and stock dividends, require changes in the common shares outstanding and the stock prices of the companies in the SPX, and do not require index divisor adjustments.

To prevent the level of the SPX from changing due to corporate actions, corporate actions which affect the total market value of the SPX require an index divisor adjustment. By adjusting the index divisor for the change in market value, the level of the SPX remains constant and does not reflect the corporate actions of individual companies in the SPX. Index divisor adjustments are made after the close of trading and after the calculation of the SPX closing level.

Changes in a company's total shares outstanding of 5% or more due to public offerings are made as soon as reasonably possible. Other changes of 5% or more (for example, due to tender offers, Dutch auctions, voluntary exchange offers, company stock repurchases, private placements, acquisitions of private companies or non-index companies that do not trade on a major exchange, redemptions, exercise of options, warrants, conversion of preferred stock, notes, debt, equity participations, at-the-market stock offerings or other recapitalizations) are made weekly, and are generally announced on Fridays for implementation after the close of trading the following Friday (one week later). If a 5% or more share change causes a company's IWF to change by five percentage points or more, the IWF is updated at the same time as the share change. IWF changes resulting from partial tender offers are considered on a case-by-case basis.

License Agreement

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The Notes are not sponsored, endorsed, sold or promoted by S&P Dow Jones Indices LLC, Standard & Poor's Financial Services LLC or any of their respective affiliates (collectively, "S&P Dow Jones Indices"). S&P Dow Jones Indices make no representation or warranty, express or implied, to the holders of the Notes or any member of the public regarding the advisability of investing in securities generally or in the Notes particularly or the ability of the SPX to track general market performance. S&P Dow Jones Indices' only relationship to us with respect to the SPX is the licensing of the SPX and certain trademarks, service marks and/or trade names of S&P Dow Jones Indices and/or its third party licensors. The SPX is determined, composed and calculated by S&P Dow Jones Indices without regard to us or the Notes. S&P Dow Jones Indices have no obligation to take our needs or the needs of holders of the Notes into consideration in determining, composing or calculating the SPX. S&P Dow Jones Indices are not responsible for and have not participated in the determination of the prices, and amount of the Notes or the timing of the issuance or sale of the Notes or in the determination or calculation of the equation by which the Notes are to be converted into cash. S&P Dow Jones Indices have no obligation or liability in connection with the administration, marketing or trading of the Notes. There is no assurance that investment products based on the SPX will accurately track index performance or provide positive investment returns. S&P Dow Jones Indices LLC and its subsidiaries are not investment advisors. Inclusion of a security or futures contract within an index is not a recommendation by S&P Dow Jones Indices to buy, sell, or hold such security or futures contract, nor is it considered to be investment advice. Notwithstanding the foregoing, CME Group Inc. and its affiliates may independently issue and/or sponsor financial products unrelated to the Notes currently being issued by us, but which may be similar to and competitive with the Notes. In addition, CME Group Inc. and its affiliates may trade financial products which are linked to the performance of the SPX. It is possible that this trading activity will affect the value of the Notes.

S&P DOW JONES INDICES DO NOT GUARANTEE THE ADEQUACY, ACCURACY, TIMELINESS AND/OR THE COMPLETENESS OF THE SPX OR ANY DATA RELATED THERETO OR ANY COMMUNICATION, INCLUDING BUT NOT LIMITED TO, ORAL OR WRITTEN COMMUNICATION (INCLUDING ELECTRONIC COMMUNICATIONS) WITH RESPECT THERETO. S&P DOW JONES INDICES SHALL NOT BE SUBJECT TO ANY DAMAGES OR LIABILITY FOR ANY ERRORS, OMISSIONS, OR DELAYS THEREIN. S&P DOW JONES INDICES MAKE NO EXPRESS OR IMPLIED WARRANTIES, AND EXPRESSLY DISCLAIMS ALL WARRANTIES, OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE OR USE OR AS TO RESULTS TO BE OBTAINED BY US, HOLDERS OF THE NOTES, OR ANY OTHER PERSON OR ENTITY FROM THE USE OF THE SPX OR WITH RESPECT TO ANY DATA RELATED THERETO. WITHOUT LIMITING ANY OF THE FOREGOING, IN NO EVENT WHATSOEVER SHALL S&P DOW JONES INDICES BE LIABLE FOR ANY INDIRECT, SPECIAL, INCIDENTAL, PUNITIVE, OR CONSEQUENTIAL DAMAGES INCLUDING BUT NOT LIMITED TO, LOSS OF PROFITS, TRADING LOSSES, LOST TIME OR GOODWILL, EVEN IF THEY HAVE BEEN ADVISED OF THE POSSIBILITY OF SUCH DAMAGES, WHETHER IN CONTRACT, TORT, STRICT LIABILITY, OR OTHERWISE. THERE ARE NO THIRD PARTY BENEFICIARIES OF ANY AGREEMENTS OR ARRANGEMENTS BETWEEN S&P DOW JONES INDICES AND US, OTHER THAN THE LICENSORS OF S&P DOW JONES INDICES.

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Historical Information
The graph below sets forth the information relating to the historical performance of the SPX. In addition, below the graph is a table setting forth the intra-day high, intra-day low and period-end closing levels of the SPX. The information provided in this table is for the four calendar quarters of 2013 through 2017, and for the period from January 1, 2018 through March 12, 2018.

We obtained the information regarding the historical performance of the SPX in the chart below from Bloomberg Financial Markets. We have not independently verified the accuracy or completeness of the information obtained from Bloomberg Financial Markets. The historical performance of the SPX should not be taken as an indication of its future performance, and no assurance can be given as to the Final Level of the SPX. We cannot give you assurance that the performance of the SPX will result in any positive return on your initial investment.
S&P 500® Index ("SPX")

Period-Start Date	Period-End Date	High Intra-Day Level of this Reference Asset	Low Intra-Day Level of this Reference Asset	Period-End Closing Level of this Reference Asset
1/1/2013	3/31/2013	1,570.28	1,426.19	1,569.19
4/1/2013	6/30/2013	1,687.18	1,536.03	1,606.28
7/1/2013	9/30/2013	1,729.86	1,604.57	1,681.55
10/1/2013	12/31/2013	1,849.44	1,646.47	1,848.36
1/1/2014	3/31/2014	1,883.97	1,737.92	1,872.34
4/1/2014	6/30/2014	1,968.17	1,814.36	1,960.23
7/1/2014	9/30/2014	2,019.26	1,904.78	1,972.29
10/1/2014	12/31/2014	2,093.55	1,820.66	2,058.90
1/1/2015	3/31/2015	2,119.59	1,980.90	2,067.89
4/1/2015	6/30/2015	2,134.72	2,048.38	2,063.11
7/1/2015	9/30/2015	2,132.82	1,867.01	1,920.03
10/1/2015	12/31/2015	2,116.48	1,893.70	2,043.94
1/1/2016	3/31/2016	2,072.21	1,810.10	2,059.74
4/1/2016	6/30/2016	2,120.55	1,991.68	2,098.86
7/1/2016	9/30/2016	2,193.81	2,074.02	2,168.27
10/1/2016	12/31/2016	2,277.53	2,083.79	2,238.83
1/1/2017	3/31/2017	2,400.98	2,245.13	2,362.72
4/1/2017	6/30/2017	2,453.82	2,328.95	2,423.41
7/1/2017	9/30/2017	2,519.44	2,407.70	2,519.36
10/1/2017	12/31/2017	2,694.97	2,520.40	2,673.61
1/1/2018	3/12/2018	2,872.87	2,532.69	2,783.02

PAST PERFORMANCE IS NOT INDICATIVE OF FUTURE RESULTS.

Absolute Return Buffered Enhanced Return
Notes Linked to a Basket of Equity Indices,
Due September 15, 2023

The Dow Jones Industrial Average® (“INDU”)

The INDU is a price-weighted index, which means an underlying stock’s weight in the INDU is based on its price per share rather than the total market capitalization of the issuer. The INDU is designed to provide an indication of the composite performance of 30 common stocks of corporations representing a broad cross-section of U.S. industry. The corporations represented in the INDU tend to be market leaders in their respective industries and their stocks are typically widely held by individuals and institutional investors.

The INDU is maintained by an Averages Committee comprised of the Managing Editor of The Wall Street Journal (“WSJ”), the head of Dow Jones Indexes research and the head of CME Group Inc. research. The Averages Committee was created in March 2010, when Dow Jones Indexes became part of CME Group Index Services, LLC, a joint venture company owned 90% by CME Group Inc. and 10% by Dow Jones & Company. Generally, composition changes occur only after mergers, corporate acquisitions or other dramatic shifts in a component’s core business. When such an event necessitates that one component be replaced, the entire INDU is reviewed. As a result, when changes are made they typically involve more than one component. While there are no rules for component selection, a stock typically is added only if it has an excellent reputation, demonstrates sustained growth, is of interest to a large number of investors and accurately represents the sector(s) covered by the average.

Changes in the composition of the INDU are made entirely by the Averages Committee without consultation with the corporations represented in the INDU, any stock excily:times;border-bottom:solid #000000 1.0pt;">

(In millions)

Liabilities and Equity

Current Liabilities

Short-term borrowings

$339.9 $855.7

Current portion of long-term debt

1,830.6 2,591.5

Accounts payable and accrued liabilities

1,582.5 2,370.1

Customer deposits and collateral

114.9 120.3

Derivative liabilities

1,272.8 1,241.8

Unamortized energy contract liabilities

428.7 393.5

Accrued expenses

278.3 373.1

Other

456.6 514.2

Total current liabilities

6,304.3 8,460.2

Deferred Credits and Other Noncurrent Liabilities

Deferred income taxes

937.1 677.0

Asset retirement obligations

1,022.6 987.3

Derivative liabilities

937.5 1,115.0

Unamortized energy contract liabilities

853.7 906.4

Defined benefit obligations

1,061.3 1,354.3

Deferred investment tax credits

41.1 44.1

Other

256.0 249.6

Total deferred credits and other noncurrent liabilities

5,109.3 5,333.7

Long-term Debt, Net of Current Portion

4,817.0
5,098.7

Equity

Common shareholders' equity:

Common stock

3,191.5 3,164.5

Retained earnings

2,002.7 2,228.7

Accumulated other comprehensive loss

(1,662.3) (2,211.8)

Total common shareholders' equity

3,531.9 3,181.4

BGE preference stock not subject to mandatory redemption

190.0 190.0

Noncontrolling interests

45.9 20.1

Total equity

3,767.8 3,391.5

Commitments, Guarantees, and Contingencies (see Notes)

Total Liabilities and Equity

$
19,998.4
$
22,284.1

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

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CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

Constellation Energy Group, Inc. and Subsidiaries

Six Months Ended June 30,	**2009**	2008
	(In millions)	
Cash Flows From Operating Activities		
Net (loss) income	**$ (91.4)**	$ 324.4
Adjustments to reconcile to net cash provided by operating activities		
Depreciation, depletion, and amortization	**297.5**	290.2
Amortization of nuclear fuel	**67.0**	59.1
Amortization of energy contracts	**(86.7)**	(117.1)
All other amortization	**74.9**	8.3
Accretion of asset retirement obligations	**36.1**	33.6
Deferred income taxes	**(121.6)**	39.2
Investment tax credit adjustments	**(3.0)**	(3.2)
Deferred fuel costs	**32.4**	19.7
Defined benefit obligation expense	**64.7**	55.5
Defined benefit obligation payments	**(328.6)**	(100.3)
Workforce reduction costs	**11.2**	
Impairment losses and other costs	**95.8**	
Impairment losses on nuclear decommissioning trust assets	**62.4**	12.5
Merger termination and strategic alternatives costs	**37.2**	
Loss (gain) on divestitures	**464.1**	(99.2)
Gains on termination of contracts		(68.9)
Accrual of Maryland settlement agreement credit		188.2
Equity in earnings of affiliates less than dividends received	**18.5**	7.4
Derivative contracts classified as financing activities under SFAS No. 149	**785.3**	0.5
Changes in:		
Accounts receivable, excluding margin	**599.2**	(521.7)
Derivative assets and liabilities, excluding collateral	**185.2**	(700.6)
Net collateral and margin	**1,094.9**	525.9
Materials, supplies, and fuel stocks	**323.4**	(235.5)
Other current assets	**237.0**	11.2
Accounts payable and accrued liabilities	**(786.1)**	1,051.7
Other current liabilities	**(156.0)**	(247.1)
Other	**51.0**	6.2
Net cash provided by operating activities	**2,964.4**	540.0
Cash Flows From Investing Activities		
Investments in property, plant and equipment	**(809.1)**	(869.5)
Asset and business acquisitions, net of cash acquired		(312.4)
Investments in nuclear decommissioning trust fund securities	**(233.4)**	(282.7)
Proceeds from nuclear decommissioning trust fund securities	**214.7**	264.0
Proceeds from sales of investments and other assets	**80.9**	217.0
Contract and portfolio acquisitions	**(2,153.7)**	
Decrease (increase) in restricted funds	**1,004.4**	(196.9)
Other	**(1.8)**	12.9
Net cash used in investing activities	**(1,898.0)**	(1,167.6)
Cash Flows From Financing Activities		
Net (repayment) issuance of short-term borrowings	**(515.8)**	103.7
Proceeds from issuance of common stock	**13.6**	8.3
Proceeds from issuance of long-term debt	**109.0**	1,100.0
Repayment of long-term debt	**(1,180.3)**	(265.1)
Debt issuance costs	**(62.8)**	(15.6)
Common stock dividends paid	**(133.7)**	(165.0)
BGE preference stock dividends paid	**(6.6)**	(6.6)

Proceeds from contract and portfolio acquisitions	**2,243.1**	
Derivative contracts classified as financing activities under SFAS No. 149	**(785.3)**	(0.5)
Other	**11.8**	3.2
Net cash (used in) provided by financing activities	**(307.0)**	762.4
Net Increase in Cash and Cash Equivalents	**759.4**	134.8
Cash and Cash Equivalents at Beginning of Period	**202.2**	1,095.9
Cash and Cash Equivalents at End of Period	**$ 961.6**	$ 1,230.7

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

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CONSOLIDATED STATEMENTS OF INCOME (LOSS) (UNAUDITED)

Baltimore Gas and Electric Company and Subsidiaries

	Three Months Ended June 30,		*Six Months Ended June 30,*	
	2009	**2008**	**2009**	**2008**
	(In millions)			
Revenues				
Electric revenues	**$ 655.7**	$ 448.7	**$ 1,462.5**	$ 1,158.1
Gas revenues	**111.7**	188.1	**498.6**	584.5
Total revenues	**767.4**	636.8	**1,961.1**	1,742.6
Expenses				
Operating expenses				
Electricity purchased for resale	**402.5**	404.3	**927.7**	859.6
Gas purchased for resale	**51.6**	127.7	**309.7**	397.7
Operations and maintenance	**148.9**	136.8	**275.9**	270.4
Depreciation and amortization	**65.7**	59.0	**132.6**	121.7
Taxes other than income taxes	**44.4**	40.1	**92.2**	86.6
Total expenses	**713.1**	767.9	**1,738.1**	1,736.0
Income (Loss) from Operations	**54.3**	(131.1)	**223.0**	6.6
Other Income	**7.2**	6.3	**14.7**	14.2
Fixed Charges				
Interest expense	**36.0**	32.0	**72.7**	67.0
Allowance for borrowed funds used during construction	**(1.1)**	(1.1)	**(2.1)**	(2.1)
Total fixed charges	**34.9**	30.9	**70.6**	64.9
Income (Loss) Before Income Taxes	**26.6**	(155.7)	**167.1**	(44.1)
Income Taxes	**10.6**	(51.5)	**66.1**	(16.1)
Net Income (Loss)	**16.0**	(104.2)	**101.0**	(28.0)
Preference Stock Dividends	**3.3**	3.3	**6.6**	6.6
Net Income (Loss) Attributable to Common Stock before Noncontrolling Interests	**12.7**	(107.5)	**94.4**	(34.6)
Net Loss Attributable to Noncontrolling Interests		0.1		0.2
Net Income (Loss) Attributable to Common Stock	**$ 12.7**	$ (107.4)	**$ 94.4**	$ (34.4)

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

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CONSOLIDATED BALANCE SHEETS

Baltimore Gas and Electric Company and Subsidiaries

	*June 30, 2009**	*December 31, 2008*
	(In millions)	
Assets		
Current Assets		
Cash and cash equivalents	**$ 4.6**	$ 10.7
Accounts receivable (net of allowance for uncollectibles of **$51.2** and $33.3, respectively)	**304.6**	327.0
Accounts receivable, unbilled (net of allowance for uncollectibles of **$0.9** and $0.9, respectively)	**171.9**	232.3
Investment in cash pool, affiliated company	**154.0**	148.8
Accounts receivable, affiliated companies	**2.1**	4.3
Fuel stocks	**59.1**	143.7
Materials and supplies	**35.2**	38.4
Prepaid taxes other than income taxes	**0.5**	51.0
Regulatory assets (net)	**63.5**	79.7
Restricted cash	**23.0**	23.7
Other	**3.4**	10.8
Total current assets	**821.9**	1,070.4
Investments and Other Assets		
Regulatory assets (net)	**454.5**	494.7
Receivable, affiliated company	**316.4**	161.1
Other	**122.0**	131.6
Total investments and other assets	**892.9**	787.4
Utility Plant		
Plant in service		
Electric	**4,604.4**	4,493.7
Gas	**1,231.0**	1,221.1
Common	**495.5**	476.3
Total plant in service	**6,330.9**	6,191.1
Accumulated depreciation	**(2,255.5)**	(2,191.0)
Net plant in service	**4,075.4**	4,000.1
Construction work in progress	**232.3**	225.7
Plant held for future use	**2.3**	2.6
Net utility plant	**4,310.0**	4,228.4
Total Assets	**$ 6,024.8**	$ 6,086.2

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

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CONSOLIDATED BALANCE SHEETS

Baltimore Gas and Electric Company and Subsidiaries

	June 30, 2009*	December 31, 2008
	(In millions)	
Liabilities and Equity		
Current Liabilities		
Short-term borrowings	**$ 339.9**	$ 370.0
Current portion of long-term debt	**66.5**	90.0
Accounts payable and accrued liabilities	**119.4**	231.0
Accounts payable and accrued liabilities, affiliated companies	**58.7**	97.0
Customer deposits	**74.0**	72.3
Current portion of deferred income taxes	**27.8**	40.2
Accrued taxes	**51.1**	18.8
Accrued expenses and other	**86.5**	98.4
Total current liabilities	**823.9**	1,017.7
Deferred Credits and Other Liabilities		
Deferred income taxes	**904.6**	843.3
Payable, affiliated company	**244.1**	243.2
Deferred investment tax credits	**10.1**	10.6
Other	**24.8**	28.6
Total deferred credits and other liabilities	**1,183.6**	1,125.7
Long-term Debt		
Rate stabilization bonds	**537.8**	564.4
Other long-term debt	**1,443.0**	1,443.0
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 businesses		25.0
Unamortized discount and premium	**(2.3)**	(2.4)
Current portion of long-term debt	**(66.5)**	(90.0)
Total long-term debt	**2,169.7**	2,197.7
Equity		
Common shareholder's equity:		
Common stock	**912.2**	912.2
Retained earnings	**719.8**	625.4
Accumulated other comprehensive income	**0.6**	0.6
Total common shareholder's equity	**1,632.6**	1,538.2
Preference stock not subject to mandatory redemption	**190.0**	190.0
Noncontrolling interest	**25.0**	16.9
Total equity	**1,847.6**	1,745.1
Commitments, Guarantees, and Contingencies (see Notes)		

Total Liabilities and Equity	**$ 6,024.8**	$ 6,086.2

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

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CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

Baltimore Gas and Electric Company and Subsidiaries

Six Months Ended June 30,	**2009**	2008
	(In millions)	
Cash Flows From Operating Activities		
Net income (loss)	**$ 101.0**	$ (28.0)
Adjustments to reconcile to net cash provided by operating activities		
Depreciation and amortization	**132.6**	121.7
Other amortization	**3.7**	6.9
Deferred income taxes	**46.7**	11.3
Investment tax credit adjustments	**(0.5)**	(0.7)
Deferred fuel costs	**32.4**	19.7
Defined benefit plan expenses	**17.5**	18.7
Allowance for equity funds used during construction	**(4.2)**	(4.0)
Accrual of Maryland settlement agreement credit		188.2
Changes in:		
Accounts receivable	**82.8**	36.7
Accounts receivable, affiliated companies	**2.2**	(3.6)
Materials, supplies, and fuel stocks	**87.8**	5.0
Other current assets	**57.9**	(54.4)
Accounts payable and accrued liabilities	**(111.6)**	68.7
Accounts payable and accrued liabilities, affiliated companies	**(38.3)**	50.7
Other current liabilities	**10.6**	88.9
Long-term receivables and payables, affiliated companies	**(171.8)**	(42.0)
Other	**(3.1)**	(14.9)
Net cash provided by operating activities	**245.7**	468.9
Cash Flows From Investing Activities		
Utility construction expenditures (excluding equity portion of allowance for funds used during construction)	**(166.7)**	(219.6)
Change in cash pool at parent	**(5.2)**	(102.7)
Sales of investments and other assets		12.9
Decrease (increase) in restricted funds	**0.7**	(207.7)
Net cash used in investing activities	**(171.2)**	(517.1)
Cash Flows From Financing Activities		
Proceeds from issuance of long-term debt		400.0
Repayment of long-term debt	**(51.6)**	(259.5)
Net repayment of short-term borrowings	**(30.1)**	
Debt issuance costs	**(0.3)**	(2.4)
Contribution from noncontrolling interest	**8.0**	
Preference stock dividends paid	**(6.6)**	(6.6)
Distribution to parent		(86.0)
Net cash (used in) provided by financing activities	**(80.6)**	45.5
Net Decrease in Cash and Cash Equivalents	**(6.1)**	(2.7)
Cash and Cash Equivalents at Beginning of Period	**10.7**	17.6

Cash and Cash Equivalents at End of Period	**$ 4.6**	$ 14.9

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

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.

We have evaluated events or transactions that occurred after June 30, 2009 for inclusion in these financial statements through August 7, 2009, the date these financial statements were issued.

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.

Reclassifications

We have reclassified certain prior-period amounts:

- In accordance with Statement of Financial Accounting Standards (SFAS) No. 160, *Noncontrolling Interests in Consolidated Financial Statements, an amendment of ARB No. 51*, which we adopted on January 1, 2009, we have separately presented:
  - "Net income (loss) attributable to noncontrolling interests" on our, and BGE's, Consolidated Statements of Income (Loss),
  - "Noncontrolling interests" and "BGE Preference Stock Not Subject to Mandatory Redemption" as noncontrolling interests on our Consolidated Balance Sheets,
  - "Comprehensive income attributable to noncontrolling interests, net of taxes" in our Statements of Comprehensive Income (Loss), and
  - "BGE preference stock dividends paid" in the financing section of our Consolidated Statements of Cash Flows.

We discuss our adoption of SFAS No. 160 in more detail on page 41.

We also made the following reclassifications:

- We have separately presented "Amortization of nuclear fuel," "Amortization of energy contracts," and "All other amortization" that were previously reported within "Depreciation, depletion, and amortization" on our Consolidated Statements of Cash Flows.
- We have separately presented "Net collateral and margin" that was previously reported within other working capital accounts on our Consolidated Statements of Cash Flows.
- We have separately presented "Other amortization" that was previously reported within "Depreciation and amortization" on BGE's Consolidated Statements of Cash Flows.

Investment Agreement with EDF Group

On December 17, 2008, we entered into an Investment Agreement with EDF Group and related entities (EDF) under which EDF will purchase from us a 49.99% membership interest in our nuclear generation and operation business for $4.5 billion (subject to certain adjustments). We discuss the Investment Agreement with EDF in more detail in *Note 15* of our 2008 Annual Report on Form 10-K.

Merger Termination and Strategic Alternatives Costs

We incurred costs during the quarter and six months ended June 30, 2009 related to the terminated merger agreement with MidAmerican Energy Holdings Company (MidAmerican), the conversion of our Series A Preferred Stock, the transactions related to EDF, and other strategic alternatives costs. These costs totaled $4.0 million pre-tax and $46.3 million pre-tax for the quarter and six months ended June 30, 2009, respectively, and primarily relate to the first quarter of 2009 write-off of the unamortized debt discount associated with the 14% Senior Notes (Senior Notes) that were repaid in full to MidAmerican in January 2009.

Variable Interest Entities

As of June 30, 2009, we consolidated three variable interest entities (VIE) in which we were the primary beneficiary, and we had significant interests in seven VIEs for which we did not have controlling financial interests and, accordingly, were not the primary beneficiary. We discuss our VIEs in more detail in *Note 4* of our 2008 Annual Report on Form 10-K.

Consolidated Variable Interest Entities

In 2007, BGE formed RSB BondCo LLC (BondCo), a special purpose bankruptcy-remote limited liability company, to acquire and hold rate stabilization property and to issue and service bonds secured by the rate stabilization property. In June 2007, BondCo purchased rate stabilization property from BGE, including the right to

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assess, collect, and receive non-bypassable rate stabilization charges payable by all residential electric customers of BGE. These charges are being assessed in order to recover previously incurred power purchase costs that BGE deferred pursuant to Senate Bill 1. We discuss Senate Bill 1 in more detail in *Management's Discussion and Analysis* section of our 2008 Annual Report on Form 10-K.

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

The BondCo assets are restricted and can only be used to settle the obligations of BondCo. Further, BGE is required to remit all payments it receives from customers for rate stabilization charges to BondCo. During the quarter and six months ended June 30, 2009, BGE remitted $17.6 million and $42.1 million, respectively, to BondCo.

BGE did not provide any additional financial support to BondCo during the quarter and six months ended June 30, 2009. Further, BGE does not have any contractual commitments or obligations to provide additional financial support to BondCo unless additional rate stabilization bonds are issued. The BondCo creditors do not have any recourse to the general credit of BGE in the event the rate stabilization charges are not sufficient to cover the bond principal and interest payments of BondCo.

During the second quarter of 2009, our retail gas customer supply operation formed two new entities and combined them with our existing retail gas customer supply operation into a retail gas entity group for the purpose of entering into a collateralized gas supply agreement (GSA) with a third party gas supplier. While we own 100% of these entities, we determined that the retail gas entity group is a VIE because we provide additional credit support to the gas supplier in the form of a letter of credit and a parental guarantee. We are the primary beneficiary of the retail gas entity group; accordingly, we consolidate the retail gas entity group as a VIE, including the existing retail gas customer supply operation, which we formerly consolidated as a voting interest entity.

The gas supply arrangement is collateralized as follows:

- The assets of the retail gas entity group must be used to settle obligations under the third party gas supply agreement before it can make any distributions to us,
- The third party gas supplier has a collateral interest in all of the assets and equity of the retail gas entity group, and
- We provided a $100 million parental guarantee and a $160 million letter of credit to the third party gas supplier in support of the retail gas entity group. The letter of credit has been decreased to $100 million as of June 30, 2009.

Other than credit support provided by the parental guarantee and the letter of credit, we do not have any contractual or other obligations to provide additional financial support to the retail gas entity group. The retail gas entity group creditors do not have any recourse to our general credit. Finally, we did not provide any financial support to the retail gas entity group during the quarter ended June 30, 2009, other than the initial equity contribution, parental guarantee and the letter of credit.

The carrying amounts and classification of the above consolidated VIEs' assets and liabilities included in our consolidated financial statements at June 30, 2009 are as follows:

	(In millions)
Current assets	$ 542.0
Noncurrent assets	63.0
Total Assets	$ 605.0
Current liabilities	$ 467.6
Noncurrent liabilities	479.8
Total Liabilities	$ 947.4

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

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

Unconsolidated Variable Interest Entities

As of June 30, 2009, we had significant interests in seven VIEs for which we were not the primary beneficiary. We have not provided any material financial or other support to these entities during the quarter and six months ended June 30, 2009.

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

VIE Category	Nature of Entity Financing	Nature of Constellation Energy Involvement	Obligations or Requirement to Provide Financial Support	Date of Involvement
Power contract monetization entities (2 entities)	Combination of debt and equity financing	Power sale agreements, loans, and guarantees	$40.4 million in letters of credit	March 2005
Power projects and fuel supply entities (4 entities)	Combination of debt and equity financing	Equity investments and guarantees	$2.0 million debt guarantee and working capital funding	Prior to 2003
Retail gas supply contract (1 entity)	Equity financing and proceeds from gas sales	Gas supply agreement	$3.8 million in obligations under gas supply agreement	February 2008

We discuss the nature of our involvement with the power contract monetization VIEs in detail in *Note 4* of our 2008 Annual Report on Form 10-K.

The following is summary information available as of June 30, 2009 about these entities:

	Power Contract Monetization VIEs	All Other VIEs	Total
	(In millions)		
Total assets	$ 574.0	$ 322.2	$ 896.2
Total liabilities	466.1	92.3	558.4
Our ownership interest		56.4	56.4
Other ownership interests	107.9	173.5	281.4
Our maximum exposure to loss	40.4	62.2	102.6
Carrying amount and location of variable interest on balance sheet:			
-Other investments		56.4	56.4

Our maximum exposure to loss is the loss that we would incur in the unlikely event that our interests in all of these entities were to become worthless and we were required to fund the full amount of all guarantees associated with these entities. Our maximum exposure to loss as of June 30, 2009 consists of the following:

- outstanding receivables, loans, and letters of credit totaling $44.2 million,
- the carrying amount of our investment totaling $56.4 million, and
- debt and payment guarantees totaling $2.0 million.

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

Impairment Losses and Other Costs

Available for Sale Securities

We evaluated certain of our investments in equity securities during the six months ended June 30, 2009. The investments we evaluated included our nuclear decommissioning trust fund assets and other marketable securities. We record an impairment charge if an investment has experienced a decline in fair value to a level less than our carrying value and the decline is "other than temporary."

In making this determination, we evaluate the reasons for an investment's decline in value, the extent and duration of that decline, and factors that indicate whether and when the value will recover. For securities held in our nuclear decommissioning trust fund for which the market value is below book value, the decline in fair value is considered other than temporary and we write them down to fair value. We discuss our impairment policy for our nuclear decommissioning trust fund assets and other marketable securities in more detail in *Note 1* to our 2008 Annual Report on Form 10-K.

The fair values of certain of our marketable securities and certain of the securities held in our nuclear decommissioning trust fund declined below book value. As a result, we recorded a $1.9 million pre-tax impairment charge for the quarter ended June 30, 2009 and a $62.4 million pre-tax impairment charge for the six months ended June 30, 2009 for our nuclear decommissioning trust fund assets in the "Other income (expense)" line in our Consolidated Statements of Income (Loss). In addition, we recorded all other changes in the fair value of our nuclear decommissioning trust fund assets that are not impaired in other comprehensive (loss) income. We also recorded an impairment charge of $0.5 million for other marketable securities during the six months ended June 30, 2009.

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

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Equity Method Investments

Shipping Joint Venture

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

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

Constellation Energy Partners LLC

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

The decline in fair value of our investment in CEP reflected a number of other factors, including:

- continuing difficulties in the financial and credit markets in the United States,
- decreases in the market price of natural gas and oil,
- the effect of these factors on market perceptions of gas exploration and production master limited partnerships, and
- factors related to Constellation Energy's financial condition and possible sale of its investment in CEP.

As a result of evaluating these factors, we determined that the decline in the value of our investment is other than temporary. Therefore, we recorded a $14.0 million pre-tax impairment charge at March 31, 2009 to write-down our investment to fair value. We recorded this charge in "Impairment losses and other costs" in our Consolidated Statements of Income (Loss). We did not record an impairment charge in the second quarter of 2009. To the extent that the market price of our investment declines further in future quarters, we may record additional write-downs if we determine that those additional declines are other than temporary.

Other Costs

During the quarter and six months ended June 30, 2009, we recorded $8.2 million and $22.3 million pre-tax charges, respectively, in the "Impairment losses and other costs" line in our Consolidated Statements of Income (Loss) primarily related to certain long-lived assets that ceased to be used in connection with the divestiture of a majority of our international commodities operation and our Houston-based gas trading operation as well as the write-off of an uncollectible advance to an affiliate.

Workforce Reduction Costs

We incurred workforce reduction costs during the six months ended June 30, 2009 primarily related to the divestiture of a majority of our international commodities operation as well as some smaller restructurings elsewhere in our organization. We recognized an $11.2 million pre-tax charge during the six months ended June 30, 2009 related to the elimination of approximately 180 positions. We expect these restructurings will be completed within the next 12 months. The following table summarizes the status of the involuntary severance liability at June 30, 2009:

	(In millions)

Initial severance liability balance	$	10.8
Additional expense recorded in the second quarter of 2009		0.4
Amounts recorded as pension and postretirement liabilities		
Net cash severance liability		11.2
Cash severance payments		(8.1)
Other		
Severance liability balance at June 30, 2009	$	3.1

We also incurred costs related to workforce reduction efforts initiated across all of our operations in 2008.

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The following table summarizes the status of this involuntary severance liability at June 30, 2009:

	(In millions)
Initial severance liability balance	$ 19.7
Amounts recorded as pension and postretirement liabilities	(3.0)
Net cash severance liability	16.7
Cash severance payments	(10.5)
Other	
Severance liability balance at June 30, 2009	$ 6.2

We discuss our 2008 workforce reduction costs in more detail in *Note 2* of our 2008 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 June 30,		**Six Months Ended June 30,**	
	2009	**2008**	**2009**	**2008**
	(In millions)			
Non-dilutive stock options	**5.0**	1.3	**5.3**	0.9
Dilutive common stock equivalent shares	**0.8**	1.8	**0.5**	1.9

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

We issued to MidAmerican 19,897,322 shares of Constellation Energy's common stock upon the conversion of the Series A Preferred Stock, which happened upon the termination of the merger agreement with MidAmerican on December 17, 2008. We discuss the conversion feature of the Series A Preferred Stock in more detail in *Note 9* of our 2008 Annual Report on Form 10-K. These additional shares impacted our earnings per share for the quarter and six months ended June 30, 2009.

Accretion of Asset Retirement Obligations

We discuss our asset retirement obligations in more detail in *Note 1* of our 2008 Annual Report on Form 10-K. The change in our "Asset retirement obligations" liability during 2009 was as follows:

	(In millions)
Liability at January 1, 2009	$ 987.3
Accretion expense	36.1
Liabilities incurred	0.1
Liabilities settled	(0.3)
Revisions to cash flows	(0.4)
Other	(0.2)
Liability at June 30, 2009	$ 1,022.6

Divestitures

In 2009, we continued to implement many of the strategic initiatives we identified in 2008 to improve liquidity and reduce our business risk. We discuss these initiatives in the *Strategy* section of our 2008 Annual Report on Form 10-K.

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

the assignment and transfer of a majority of the portfolio, and

the execution of a Total Return Swap (TRS) mechanism for the remainder of the portfolio.

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

The matching contracts under the TRS include both derivatives and non-derivatives and were executed at prices that differed from market prices at closing, which resulted in a net cash payment to/from the buyers. We recorded the underlying contracts at fair value on a gross basis as assets or liabilities in our Consolidated Balance Sheets depending on whether the contract prices were above- or below-market prices at closing. As a result, the derivative contracts have been included in "Derivative Assets and Liabilities" and the nonderivative contracts have been included in "Unamortized Energy Contract Assets and Liabilities." The derivative

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contracts are subject to mark-to-market accounting until they are realized or assigned. The nonderivative contracts will be amortized into earnings as the underlying contracts are realized, or sooner if those contracts are assigned.

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

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

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

International Commodities Operation

In January 2009, we entered into a definitive agreement to sell a majority of our international commodities operation. We completed this transaction on March 23, 2009 and recognized the following impacts during the six months ended June 30, 2009:

a pre-tax loss of approximately $334.5 million representing net consideration paid to the buyer, the book value of net assets sold, and transaction costs,

a reclassification of $165.7 million in losses on previously designated cash-flow hedge contracts, for which the forecasted transactions are now deemed probable of not occurring, from "Accumulated Other Comprehensive Loss" to "Nonregulated revenues" in the Consolidated Statements of Income (Loss),

workforce reduction costs of $10.2 million, recorded as part of "Workforce reduction costs" in the Consolidated Statements of Income (Loss), and

other costs of $10.1 million related to leasehold improvements, furniture and computer hardware and software, recorded as part of "Impairment losses and other costs" in the Consolidated Statements of Income (Loss).

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

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

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

Six Months Ended June 30, 2009		
		(In millions)
Investing activities Contract and portfolio acquisitions	**$**	**(866.3)**
Financing activities Proceeds from contract and portfolio acquisitions		**863.8**
Net cash flows from contract and portfolio acquisitions	**$**	**(2.5)**

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

Houston-Based Gas and Other Trading Operations

On February 3, 2009, we entered into a definitive agreement to sell our Houston-based gas trading operation. We transferred control of this operation on April 1, 2009. In addition, in the second quarter of 2009 we also sold certain other trading operations. In total, we received proceeds of approximately $56 million, and recorded a $102.4 million net loss on these sales in the quarter ended June 30, 2009. The net loss on sale primarily relates to nonderivative accrual contracts, which were not recorded on our Consolidated Balance Sheet, the cost associated with disposing of an entire portfolio and not merely individual contracts, and the cost of capital, including contingent capital, to support the operation.

The matching derivative and nonderivative transactions under the TRS discussed above were executed at prices that differed from market prices at closing. As a result, we record the ongoing cash flows related to the out-of-the-money derivative contracts that were liabilities at inception as financing cash flows in accordance with SFAS No. 149. This resulted in cash outflows related to financing activities of $378.0 million and $695.4 million in our

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Consolidated Statements of Cash Flows for the quarter and six months ended June 30, 2009, respectively, associated with derivative liabilities that were out-of-the-money.

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

Six Months Ended June 30, 2009	***(In millions)***
Investing activities Contract and portfolio acquisitions	**$ (1,287.4)**
Financing activities Proceeds from contract and portfolio acquisitions	**1,379.3**
Net cash flows from contract and portfolio acquisitions	**$ 91.9**

In addition, we incurred other costs of $1.5 million and $5.5 million for the quarter and six months ended June 30, 2009, respectively, related to leasehold improvements, furniture, computer hardware and software costs, which are recorded as part of "Impairment losses and other costs" on our Consolidated Statements of Income (Loss).

On April 1, 2009, we executed an agreement with the buyer of our Houston-based gas trading operation under which the buyer will provide us with the gas supply needed to support our retail gas customer supply business through March 31, 2011. This agreement was structured such that our requirements to post collateral are reduced. The supplier has liens on the assets of the retail gas supply business as well as our investment in the stock of these entities to secure our obligations under the gas supply agreement. In connection with this agreement, we posted approximately $160 million of collateral. This was subsequently reduced to $100 million. The initial $160 million posted represents approximately 25 percent of the previous collateral requirements to support this operation. We discuss the impact of the gas supply agreement on our retail gas customer supply business in more detail on page 12.

Investments Classified as Available-for-Sale

We classify the following investments as available-for-sale:

- nuclear decommissioning trust funds,
- marketable equity securities, and
- trust assets securing certain executive benefits.

This means we do not expect to hold these investments to maturity, and we do not consider them trading securities. We record these investments at fair value on our Consolidated Balance Sheets.

We show the fair values, gross unrealized gains and losses, and adjusted cost basis for all of our available-for-sale securities in the following tables. We use specific identification to determine cost in computing realized gains and losses.

At June 30, 2009	***Adjusted Cost***	***Unrealized Gains***	***Unrealized Losses***	***Fair Value***
		(In millions)		
Money market funds	**$ 12.3**	**$**	**$**	**$ 12.3**
Marketable equity securities	**196.0**	**70.3**		**266.3**
Mutual fund / common	**478.5**	**49.6**		**528.1**

collective trusts				
Corporate debt	**159.4**	**18.6**		**178.0**
U.S. agencies	**42.4**	**2.2**		**44.6**
U.S. treasuries	**19.6**	**0.8**		**20.4**
State municipal bonds	**45.3**	**2.8**		**48.1**
Totals	**$ 953.5**	**$ 144.3**	**$**	**$ 1,097.8**

The unrealized gains in the preceding table consist primarily of $143.2 million at June 30, 2009 associated with the nuclear decommissioning trust funds.

The investments in our nuclear decommissioning trust funds are managed by third parties who have independent discretion over the purchases and sales of securities. We recognize impairments for any of these investments for which the fair value declines below our book value. We recognized $1.9 million and $62.4 million in pre-tax impairment losses on our nuclear decommissioning trust investments during the quarter and six months ended June 30, 2009, respectively. These impairments are included as part of gross realized losses in the following table.

Gross and net realized gains and losses on available-for-sale securities were as follows:

	Quarter Ended June 30, 2009	Six Months Ended June 30, 2009
	(In millions)	
Gross realized gains	**$ 4.3**	$ 15.2
Gross realized losses	**(3.7)**	(72.0)
Net realized gains	**$ 0.6**	$ (56.8)

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The corporate debt securities, U.S. Government agency obligations, and state municipal bonds mature on the following schedule:

At June 30, 2009	*(In millions)*
Less than 1 year	$ 11.9
1-5 years	90.7
5-10 years	93.8
More than 10 years	94.7
Total maturities of debt securities	$ 291.1

Information by Operating Segment

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

Our merchant energy business is nonregulated and includes:

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

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

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

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

upstream (exploration and production) natural gas operations, and

generation operations and maintenance.

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 renewable energy, heating, cooling, and cogeneration facilities for commercial, industrial, and governmental customers throughout North America,

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, and

develop and deploy new nuclear plants in North America.

Prior to June 30, 2009, our merchant energy business segment included additional activities that have been divested as part of our strategy to improve our liquidity and reduce our business risk. The divested activities include:

our international commodities operation, which was divested in March 2009,

our gas trading operation, which was divested on April 1, 2009, our ownership of a uranium market participant, which was divested on June 30, 2009, and

our investment in a shipping joint venture, which is expected to be divested in the third quarter of 2009.

Additionally, we entered into an Investment Agreement with EDF on December 17, 2008. See *Note 15* of our 2008 Annual Report on Form 10-K for more detail on the Investment Agreement with EDF.

We believe that the successful execution of these initiatives, as well as our other initiatives that we have undertaken to reduce risk in our merchant energy business, have reduced our exposure to activities that require contingent capital support and improved our liquidity. In turn, the results for our merchant energy business segment will be materially different from prior periods. We discuss these strategies and their effect on liquidity in *Note 8* of our 2008 Annual Report on Form 10-K.

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

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	Reportable Segments			Holding Company and Other Nonregulated Businesses		
	Merchant Energy Business	Regulated Electric Business	Regulated Gas Business		Eliminations	Consolidated
				(In millions)		
For the quarter ended June 30,						
2009						
Unaffiliated revenues	**$ 3,045.7**	**$ 655.7**	**$ 111.1**	**$ 51.6**	**$**	**$ 3,864.1**
Intersegment revenues	**155.3**		**0.6**		**(155.9)**	
Total revenues	**3,201.0**	**655.7**	**111.7**	**51.6**	**(155.9)**	**3,864.1**
Net income (loss)	**20.9**	**22.1**	**(6.2)**	**(8.5)**		**28.3**
Net income (loss) attributable to common stock	**4.1**	**19.5**	**(6.9)**	**(8.6)**		**8.1**
2008						
Unaffiliated revenues	$ 4,058.3	$ 448.7	$ 183.1	$ 66.0	$	$ 4,756.1
Intersegment revenues	221.8		5.0	0.1	(226.9)	
Total revenues	4,280.1	448.7	188.1	66.1	(226.9)	4,756.1
Net income (loss)	280.0	(101.7)	(2.3)	(1.0)		175.0
Net income (loss) attributable to common stock	279.7	(104.2)	(3.1)	(0.9)		171.5
For the six months ended June 30,						
2009						
Unaffiliated revenues	**$ 6,100.7**	**$ 1,462.5**	**$ 495.4**	**$ 108.9**	**$**	**$ 8,167.5**
Intersegment revenues	**379.8**		**3.2**		**(383.0)**	
Total revenues	**6,480.5**	**1,462.5**	**498.6**	**108.9**	**(383.0)**	**8,167.5**
Net (loss) income	**(181.8)**	**67.5**	**33.4**	**(10.5)**		**(91.4)**
Net (loss) income attributable to common stock	**(199.1)**	**62.4**	**31.9**	**(10.6)**		**(115.4)**
2008						
Unaffiliated revenues	$ 7,711.1	$ 1,158.0	$ 574.1	$ 125.1	$	$ 9,568.3
Intersegment revenues	516.0	0.1	10.4	0.2	(526.7)	
Total revenues	8,227.1	1,158.1	584.5	125.3	(526.7)	9,568.3
Net income (loss)	352.7	(65.5)	37.9	(0.7)		324.4
Net income (loss) attributable to common stock	351.9	(70.5)	36.3	(0.5)		317.2

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

Our merchant energy business operating results for the quarter and six months ended June 30, 2009 include the following after-tax charges:

impairment losses and other costs of $62.2 million and $73.4 million, respectively,

merger termination and strategic alternatives costs of $4.0 million and $46.3 million, respectively,

net loss on sale of a majority of our international commodities operation, our Houston-based gas trading operation, certain other trading operations, and a uranium market participant, the reclassification of losses on previously designated cash-flow hedges from Accumulated Other Comprehensive Loss, and earnings that are no longer part of our core business totaling $123.8 million and $308.0 million, respectively,

impairment charge related to our nuclear decommissioning trust fund assets of $6.1 million and $29.8 million, respectively, *workforce reduction costs of $1.1 million and $5.3 million, respectively, and*

amortization of credit facility amendment fees in connection with the EDF transaction of $5.2 million and $8.9 million, respectively.

Our Holding Company and Other Nonregulated businesses operating results for the quarter and six months ended June 30, 2009 reflect impairment losses and other costs of $3.2 million after-tax.

Total assets decreased approximately $2.3 billion during the six months ended June 30, 2009. The decrease primarily relates to:

our Holding Company and Other Nonregulated Businesses and is primarily related to the approximately $1 billion decline in restricted cash as a result of the repayment of the 14% Senior Notes to MidAmerican in January 2009, and

our Merchant Energy Business and is primarily related to the decrease in derivative assets, net of fair value collateral, of $533.2 million and a decrease in other net collateral and margin posted of $728.6 million, primarily associated with the divestitures and the activities to reduce risk in our Global Commodities portfolio.

Our allowance for uncollectible accounts receivable increased $19.6 million from December 31, 2008 to June 30, 2009. This increase is primarily attributable to our regulated electric and gas businesses. In the second quarter of 2009, the Maryland PSC issued a ruling which delayed BGE's ability to terminate service to customers with arrearages and offered those customers the option to enter into extended payment plans.

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Pension and Postretirement Benefits

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

	Quarter Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
	(In millions)			
Components of net periodic pension benefit cost				
Service cost	**$ 14.4**	$ 12.8	**$ 29.6**	$ 27.8
Interest cost	**31.1**	22.7	**58.3**	50.2
Expected return on plan assets	**(38.9)**	(25.0)	**(68.5)**	(55.9)
Recognized net actuarial loss	**11.1**	6.5	**21.7**	12.4
Amortization of prior service cost	**2.5**	2.6	**5.8**	5.5
Amount capitalized as construction cost	**(2.8)**	(2.1)	**(5.4)**	(4.8)
Net periodic pension benefit cost[1]	**$ 17.4**	$ 17.5	**$ 41.5**	$ 35.2

1 BGE's portion of our net periodic pension benefit cost, excluding amounts capitalized, was $4.9 million for the quarter ended June 30, 2009 and $4.2 million for the quarter ended June 30, 2008. BGE's portion of our net periodic pension benefit cost, excluding amounts capitalized, was $9.9 million for the six months ended June 30, 2009 and $8.7 million for the six months ended June 30, 2008. Net periodic pension benefit costs exclude settlement charges of $7.7 million in the quarter and six months ended June 30, 2009.

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

	Quarter Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
	(In millions)			
Components of net periodic postretirement benefit cost				
Service cost	**$ 2.0**	$ 1.9	**$ 3.6**	$ 3.6
Interest cost	**6.3**	7.2	**12.1**	13.9
Amortization of transition obligation	**0.6**	0.7	**1.1**	1.2

Recognized net actuarial loss	**0.4**	0.1	**1.1**	1.1
Amortization of prior service cost	**(1.0)**	(1.1)	**(1.8)**	(2.0)
Amount capitalized as construction cost	**(1.8)**	(1.9)	**(3.3)**	(4.0)
Net periodic postretirement benefit cost[1]	**$ 6.5**	$ 6.9	**$ 12.8**	$ 13.8

1 BGE's portion of our net periodic postretirement benefit cost, excluding amounts capitalized, was $3.5 million for the quarter ended June 30, 2009 and $4.0 million for the quarter ended June 30, 2008. BGE's portion of our net periodic postretirement benefit costs, excluding amounts capitalized, was $6.7 million for the six months ended June 30, 2009 and $7.7 million for the six months ended June 30, 2008.

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 $22 million in pension benefit payments for our non-qualified pension plans and approximately $30 million for retiree health and life insurance benefit payments during 2009. As of June 30, 2009, we contributed $297 million to our qualified pension plans. We contributed an additional $20 million in July 2009.

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Financing Activities

Credit Facilities and Short-term Borrowings

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

Constellation Energy

Constellation Energy had bank and other lines of credit under committed unsecured credit facilities totaling $5.6 billion at June 30, 2009 for short-term financial needs. We enter into these facilities to ensure adequate liquidity to support our operations.

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

These facilities can issue letters of credit, commercial paper, if available, and/or cash borrowings up to approximately $5.6 billion as shown below. As of June 30, 2009, we had approximately $2.8 billion in letters of credit issued against those facilities.

We have also included in the table below the pro forma effect on our credit facilities, which are reduced or terminated upon the closing of the transactions contemplated by the Investment Agreement with EDF, which is expected to occur in the fourth quarter of 2009:

Facility Expiration	Facility Size	Facility Size Upon Completion of the EDF Transaction
	(In billions)	
July 2012	$ 3.85	$ 2.32
November 2009[1]	1.23	
September 2013	0.35	
December 2009	0.15	
Total	$ 5.58	$ 2.32

1 Size of facility may be reduced by proceeds received from certain securities offerings or asset sales.

BGE

BGE has a $400.0 million five-year revolving credit facility expiring in 2011. BGE can borrow directly from the banks, use the facility to allow commercial paper to be issued, if available, or issue letters of credit. As of June 30, 2009, BGE had $0.5 million in letters of credit issued under this facility.

In addition, at June 30, 2009, BGE had $339.9 million in commercial paper outstanding.

Net Available Liquidity

The following table provides a summary of our net available liquidity at June 30, 2009:

	As of June 30, 2009		
	Constellation Energy	BGE	Total Consolidated

	(In billions)		
Credit facilities	$ 5.6	$ 0.4	$ 6.0
Less: Letters of credit issued	(2.8)		(2.8)
Less: Cash drawn on credit facilities			
Undrawn facilities	2.8	0.4	3.2
Less: Commercial paper outstanding		(0.3)	(0.3)
Net available facilities	2.8	0.1	2.9
Add: Cash	1.0		1.0
Add: EDF put arrangement	1.1		1.1
Net available liquidity	$ 4.9	$ 0.1	$ 5.0

Other Sources of Liquidity

In December 2008, we executed an Investment Agreement with EDF that includes an asset put arrangement that provides us with an option at any time through December 31, 2010 (or the termination of the Investment Agreement by EDF if we breach that agreement) to sell certain non-nuclear generation assets, at pre-agreed prices, to EDF for aggregate proceeds of no more than $2 billion pre-tax, or approximately $1.4 billion after-tax. The amount of after-tax proceeds will be impacted by the assets actually sold and the related tax impacts at that time. Exercise of the put arrangement is conditioned upon the receipt of regulatory approvals and third-party consents, the absence of any material liens on such assets, and the absence of a material adverse effect, as defined in the Investment Agreement. During April 2009, we received regulatory approvals and consents for the majority of the assets covered by the put arrangement. As of June 30, 2009, we have approximately $1.1 billion after-tax of liquidity available through the put arrangement. We expect to receive regulatory approval for an additional asset in the first quarter of 2010, which will increase the net after-tax

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liquidity from the put arrangement to approximately $1.4 billion.

We are actively seeking to increase available liquidity and to reduce our business risk. Specifically, we are reducing capital spending and ongoing expenses, scaling down the expected variability in long-term earnings and short-term collateral usage, and limiting our exposure to business activities that require contingent capital support. During 2009, we made progress on several other initiatives as discussed in more detail in the *Divestitures* section beginning on page 15 and the *Variable Interest Entities* section on page 12. As of June 30, 2009 we have realized substantially all of the $1 billion of the net reduction in collateral that was expected from the divestiture of these operations.

We believe that the actions that we have taken and our current net available liquidity will be sufficient to support the ongoing liquidity requirements over the next 12 months. Our liquidity projections include assumptions for commodity price changes, which are subject to significant volatility, and we are exposed to certain operational risks that could have a significant impact on our liquidity.

Credit Facility Compliance and Covenants

The credit facilities of Constellation Energy and BGE have limited material adverse change clauses, none of which would prohibit draws under the existing facilities.

Certain credit facilities of Constellation Energy contain a provision requiring Constellation Energy to maintain a ratio of debt to capitalization equal to or less than 65%. At June 30, 2009, the debt to capitalization ratio as defined in the credit agreements was 51%.

Under our $3.85 billion and $1.23 billion credit facilities, we will be required to grant a lien on certain of our generating facilities and pledge our ownership interests in our nuclear business to the lenders upon the earlier of (i) the closing of the Investment Agreement with EDF or (ii) the date on which both the Investment Agreement is terminated and our Standard & Poors (S&P) or Fitch senior unsecured debt credit rating is below BBB- or our Moody's senior unsecured debt credit rating is below Baa3.

Our $1.23 billion credit facility requires us to maintain consolidated earnings before interest, taxes, depreciation, and amortization to consolidated interest expense ratio of at least 2.75 when our S&P senior unsecured debt rating is BBB- or lower and our Moody's senior unsecured debt rating is Baa3 or lower. Compliance with the covenant is not required as of July 31, 2009 as S&P's senior unsecured debt rating is above BBB-.

The credit agreement of BGE contains a provision requiring BGE to maintain a ratio of debt to capitalization equal to or less than 65%. At June 30, 2009, the debt to capitalization ratio for BGE as defined in this credit agreement was 52%.

Income Taxes

We compute the income tax (benefit) expense for each quarter based on the estimated annual effective tax rate for the year. The effective tax rate was 78.3% and 60.4% for the quarter and six months ended June 30, 2009, respectively, compared to 38.0% and 36.1% for the same periods of 2008. The higher effective tax rate for the quarter and six months ended June 30, 2009 reflects the impact of unfavorable nondeductible adjustments (primarily related to nondeductible dividends on the Series B Preferred Stock and the write-off of the unamortized debt discount on the Senior Notes) in relation to the lower estimated 2009 taxable income (primarily attributable to losses on the divestiture of a majority of our international commodities and our Houston-based gas trading operations).

The BGE effective tax rate was 39.8% and 39.6% for the quarter and six months ended June 30, 2009, respectively, compared to 33.1% and 36.7% for the same periods of 2008. This reflects the impact of the lower 2008 taxable income related to the Maryland settlement agreement, which increased the relative impact of favorable permanent tax adjustments on BGE's 2008 effective tax rate.

Unrecognized Tax Benefits

The following table summarizes the change in unrecognized tax benefits during 2009 and our total unrecognized tax benefits at June 30, 2009:

At June 30, 2009	***(In millions)***
Total unrecognized tax benefits, January 1, 2009	$ 189.7
	3.0

Increases in tax positions related to the current year	
Reductions in tax positions related to prior years	(7.8)
Reductions in tax positions as a result of a lapse of the applicable statute of limitations	(0.8)
Total unrecognized tax benefits, June 30, 2009[1]	$ 184.1

1 BGE's portion of our total unrecognized tax benefits at June 30, 2009 was $3.9 million.

Increases in current year and reductions in prior year tax positions are primarily due to unrecognized tax benefits for repair and depreciation deductions measured at amounts consistent with prior IRS examination results and state income tax accruals. Statutes of limitations lapsed for 2003 and 2004 tax positions related to Maryland taxes on the gas plant sale that occurred in 2006.

If the total amount of unrecognized tax benefits of $184.1 million were ultimately realized, our income tax expense would decrease by approximately $158 million. However, the $158 million includes state tax refund claims of approximately $48 million that have been disallowed by tax authorities and we believe that there is a remote likelihood of ultimately realizing any benefit from these refund claim amounts. These state refund claims may be resolved by December 31, 2009. For this reason, we believe it is reasonably possible that reductions to our total unrecognized tax benefits in the range of $40 to $50 million may occur by June 30, 2010, although these reductions are not expected to materially impact income tax expense.

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

	Quarter Ended June 30,		Six Months Ended June 30,	
	2009	**2008**	**2009**	**2008**
	(In millions)			
Interest and penalties recorded as tax expense	**$ 1.5**	$ 0.7	**$ 0.7**	$ 1.7

Accrued interest and penalties recognized in our Consolidated Balance Sheets were $11.0 million, of which BGE's portion was $0.8 million at June 30, 2009, and $10.3 million, of which BGE's portion was $0.7 million at December 31, 2008.

Taxes Other Than Income Taxes

BGE collects from certain customers franchise and other taxes that are levied by state or local governments on the sale or distribution of gas and electricity. We include these types of taxes in "Taxes other than income taxes" in our Consolidated Statements of Income (Loss). Some of these taxes are imposed on the customer and others are imposed on BGE. We account for the taxes imposed on the customer on a net basis, which means we do not recognize revenue and an offsetting tax expense for the taxes collected from customers. We account for the taxes imposed on BGE on a gross basis, which means we recognize revenue for the taxes collected from customers. Accordingly, we record the taxes accounted for on a gross basis as revenues in the accompanying Consolidated Statements of Income (Loss) for BGE as follows:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2009	**2008**	**2009**	**2008**
	(In millions)			
Taxes other than income taxes included in revenues BGE	**$ 18.5**	$ 14.3	**$ 40.1**	$ 35.2

Guarantees

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

At June 30, 2009	Stated Limit
	(In billions)
Constellation Energy guarantees	$ 13.7
Merchant energy business guarantees	0.1
BGE guarantees	0.3
Total guarantees	$ 14.1

At June 30, 2009, Constellation Energy had a total of $14.1 billion in guarantees outstanding related to loans, credit facilities, and contractual performance of certain of its subsidiaries as described below.

Constellation Energy guaranteed a face amount of $13.7 billion as follows:

Constellation Energy guaranteed a face amount of $12.7 billion on behalf of our merchant energy subsidiaries to allow those subsidiaries the flexibility needed to conduct business with counterparties without having to post other forms of collateral. Our estimated net exposure for obligations under commercial transactions covered by these guarantees was approximately $2.5 billion at June 30, 2009, which represents the total amount the parent company could be required to fund based on June 30, 2009 market prices. For those guarantees related to our derivative liabilities, the fair value of the obligation is recorded in our Consolidated Balance Sheets.

Constellation Energy guaranteed $0.9 billion primarily on behalf of our nuclear generating facilities for nuclear insurance and credit support to ensure these plants have funds to meet

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expenses and obligations to safely operate and maintain the plants.

Constellation Energy guaranteed $0.1 billion to its other nonregulated businesses.

Our merchant energy business guaranteed $72.0 million for loans, performance guarantees and other payment obligations primarily related to certain power projects in which we have an investment.

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

Commitments and Contingencies

We have made substantial commitments in connection with our 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 2009 and 2028. In addition, our merchant energy business enters into long-term contracts for the capacity and transmission rights for the delivery of energy to meet our physical obligations to our customers. These contracts expire in various years between 2009 and 2030.

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. As of June 30, 2009, these contracts expire during 2009, 2010, and 2011 and represent BGE's estimated requirements for residential customers as follows:

Contract Duration	***Percentage of Estimated Requirements***
From June 30, 2009 to May 2010	100%
From June 2010 to September 2010	75
From October 2010 to May 2011	50
From June 2011 to September 2011	25

The cost of power under these contracts is recoverable under the Provider of Last Resort agreement reached with the Maryland PSC.

Our regulated gas business enters into various long-term contracts for the procurement, transportation, and storage of gas. Our regulated gas business has gas procurement contracts that expire between 2009 and 2011, and transportation and storage contracts that expire between 2012 and 2027. The cost of gas under these contracts is recoverable under BGE's gas cost adjustment clause discussed in *Note 1* of our 2008 Annual Report on Form 10-K.

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 June 30, 2009, the total amount of commitments was $4,973.4 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 2019 and provide for the sale of energy to electricity distribution utilities and certain retail customers. Our power sales contracts associated with power plants we own extend for terms into 2015 and provide for the sale of all or a portion of the actual output of certain of our power plants. Substantially all long-term contracts were executed at pricing that approximated market rates, including profit margin, at the time of execution.

Contingencies

Litigation

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

Merger with MidAmerican

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

The lawsuits claim that the merger consideration was inadequate and did not maximize value for shareholders, that the sales process leading up to the merger was unreasonably short and procedurally flawed, and that unreasonable deal protection devices were agreed to in order to ward off competing bids and coerce shareholders into accepting the merger. The federal lawsuits also assert that the conversion of the Preferred Stock issued to MidAmerican into debt is not permitted under Maryland law. The lawsuits seek declaratory judgments establishing the unenforceability of the merger based on the alleged breaches of duty, injunctive relief to enjoin the merger, rescission of the merger or rescissory damages, the imposition of a constructive trust in favor of shareholders of any benefits received by the individual members of the Board of Directors of Constellation Energy, and reasonable costs and expenses, including attorney's fees.

The termination of the MidAmerican merger renders moot the claims attempting to enjoin the merger with MidAmerican. One of the federal merger cases was voluntarily dismissed on December 31, 2008. The other federal merger cases filed in the United States District Court for the District of Maryland were dismissed as moot on May 27, 2009. We believe there are meritorious defenses to the remaining claims or requests for relief. However, we are unable at this time to determine the ultimate outcome of these lawsuits or their possible effect on our financial results.

Securities Class Action

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

The Southern District of New York granted the defendants' motion to transfer the two securities class actions filed there to the District of Maryland, and the actions have since been transferred for coordination with the securities class action filed there. On June 18, 2009, the court appointed a lead plaintiff, who we expect to file a consolidated amended complaint. We are unable at this time to determine the ultimate outcome of the securities class actions or their possible effect on our, or BGE's financial results.

ERISA Actions

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

Mercury

Since September 2002, BGE, Constellation Energy, and several other defendants have been involved in numerous actions filed in the Circuit Court for Baltimore City, Maryland alleging mercury poisoning from several sources, including coal plants formerly owned by BGE. The plants are now owned by a subsidiary of Constellation Energy. In addition to BGE and Constellation Energy, approximately 11 other defendants, consisting of pharmaceutical

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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 three of the cases, involving claims related to approximately 47 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 remaining actions vigorously. However, we cannot predict the timing, or outcome, of these cases, or their possible effect on our, or BGE's, financial results.

Asbestos

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

Approximately 512 individuals who were never employees of BGE or Constellation Energy have pending claims each seeking several million dollars in compensatory and punitive damages. Cross-claims and third-party claims brought by other defendants may also be filed against BGE and Constellation Energy in these actions. To date, most asbestos claims which have been resolved have been dismissed or resolved without any payment and a small minority have been resolved for amounts that were not material to our financial results.

BGE and Constellation Energy do not know the specific facts necessary to estimate their potential liability for these claims. The specific facts we do not know include:

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

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

Environmental Matters

Solid and Hazardous Waste

In 1999, the EPA proposed to add the 68th Street Dump in Baltimore, Maryland to the Superfund National Priorities List, which is its list of sites targeted for clean-up and enforcement, and sent a general notice letter to BGE and 19 other parties identifying them as potentially liable parties at the site. In March 2004, we and other potentially responsible parties formed the 68th Street Coalition and entered into consent order negotiations with the EPA to investigate clean-up options for the site under the Superfund Alternative Sites Program. In May 2006, a settlement among the EPA and 19 of the potentially responsible parties, including BGE, with respect to investigation of the site became effective. The settlement requires the potentially responsible parties, over the course of several years, to identify contamination at the site and recommend clean-up options. BGE is fully indemnified by a wholly owned subsidiary 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 closer to completion. However, those costs could have a material effect on our financial results.

Air Quality

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

In January 2009, the EPA issued a notice of violation (NOV) to a subsidiary of Constellation Energy, as well as the other owners and the operator of the Keystone coal-fired power plant in Shelocta, Pennsylvania. We hold an approximately 21% interest in the Keystone plant. The NOV alleges that the plant performed various capital projects beginning in 1984 without complying with the new source review permitting requirements of the Clean Air Act. The EPA also contends that the alleged failure to comply with those requirements are continuing violations under the plant's air permits. The EPA could seek civil penalties under the Clean Air Act for the alleged violations.

The owners and operator of the Keystone plant are investigating the allegations and have entered into discussions with the EPA. We believe there are meritorious defenses to the allegations contained in the NOV. However, we cannot predict the outcome of this proceeding and it is not possible to determine our actual liability, if any, at this time.

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Water Quality

In October 2007, a subsidiary of Constellation Energy entered into a consent decree with the Maryland Department of the Environment relating to groundwater contamination at a third party facility that was licensed to accept fly ash, a byproduct generated by our coal-fired plants. The consent decree requires the payment of a $1.0 million penalty, remediation of groundwater contamination resulting from the ash placement operations at the site, replacement of drinking water supplies in the vicinity of the site, and monitoring of groundwater conditions. We recorded a liability in our Consolidated Balance Sheets of approximately $7.9 million, which includes the $1 million penalty and our estimate of probable costs to remediate contamination, replace drinking water supplies, monitor groundwater conditions, and otherwise comply with the consent decree. We have paid approximately $4.1 million of these costs as of June 30, 2009, resulting in a remaining liability at June 30, 2009 of $3.8 million. We estimate that it is reasonably possible that we could incur additional costs of up to approximately $10 million more than the liability that we accrued.

Insurance

We discuss our nuclear and non-nuclear insurance programs in *Note 12* of our 2008 Annual Report on Form 10-K.

Derivative Instruments

Nature of Our Business and Associated Risks

Our business activities primarily include our merchant energy business and our regulated electric and gas business. Our merchant energy business includes:

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

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

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

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

Objectives and Strategies for Using Derivatives

Risk Management Activities

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

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

Non-Risk Management Activities

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

- optimizing the margin on surplus electricity generation and load positions and surplus fuel supply and demand positions,

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- obtaining knowledge of prices and developing expertise in less-liquid markets, and
- deploying risk capital in an effort to generate returns.

Accounting for Derivative Instruments

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

Accounting Designation

We must evaluate new and existing transactions and agreements to determine whether they are derivatives, for which there are several possible accounting treatments. Mark-to-market is required as the default accounting treatment for all derivatives unless they qualify, and we specifically designate them, for one of the other accounting treatments. Derivatives designated for any of the elective accounting treatments must meet specific, restrictive criteria, both at the time of designation and on an ongoing basis. The permissible accounting treatments include:

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

We discuss our accounting policies for derivatives and hedging activities and their impacts on our financial statements in *Note 1* to our 2008 Annual Report on Form 10-K.

NPNS

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

Cash Flow Hedging

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

Commodity Cash Flow Hedges

Our merchant energy business has designated fixed-price forward contracts as cash-flow hedges of forecasted sales of energy and forecasted purchases of fuel and energy for the years 2009 through 2016. Our merchant energy business had net unrealized pre-tax losses on these cash-flow hedges recorded in "Accumulated other comprehensive loss" of $1,845.3 million at June 30, 2009 and $2,614.9 million at December 31, 2008.

We expect to reclassify $1,326.2 million of net pre-tax losses on cash-flow hedges from "Accumulated other comprehensive loss" into earnings during the next twelve months based on market prices at June 30, 2009. However, the actual amount reclassified into earnings could vary from the amounts recorded at June 30, 2009, due to future changes in market prices.

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

	Quarter Ended June 30, 2009	Quarter Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
	(In millions)			
Pre-tax (losses) gains	**$ (74.6)**	$	**$ (241.0)**	$ 0.7

The pre-tax loss reclassified in 2009 resulted from the sale of a majority of our international commodities operation and our termination of certain contracts as part of our efforts to improve liquidity and reduce risk. The forecasted transactions associated with previously designated cash-flow hedge contracts were deemed probable of not occurring.

Interest Rate Swaps Designated as Cash Flow Hedges

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

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Accumulated other comprehensive loss includes net unrealized pre-tax gains on interest rate cash-flow hedges of prior debt issuances totaling $12.1 million at June 30, 2009 and $12.0 million at December 31, 2008. We expect to reclassify $1.9 million of pre-tax net gains on these cash-flow hedges from "Accumulated other comprehensive loss" into "Interest expense" during the next twelve months. We had no hedge ineffectiveness on these swaps.

Fair Value Hedging

We elect fair value hedge accounting for a limited portion of our derivative contracts including certain interest rate swaps and certain forward contracts and price and basis swaps associated with natural gas fuel in storage. The objectives for electing fair value hedging in these situations are to manage our exposure, to optimize the mix of our fixed and floating-rate debt, and to hedge the value of our natural gas in storage. We did not have any fair value hedges related to the value of our natural gas in storage during the second quarter of 2009.

Interest Rate Swaps Designated as Fair Value Hedges

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

During 2004, we entered into interest rate swaps qualifying as fair value hedges relating to $450 million of our fixed-rate debt maturing in 2012 and 2015, and converted this notional amount of debt to floating-rate. The fair value of these hedges was an unrealized gain of $40.4 million at June 30, 2009 and $55.9 million at December 31, 2008 and was recorded as an increase in our "Derivative assets" and an increase in our "Long-term debt." We had no hedge ineffectiveness on these interest rate swaps. On July 15, 2009, we terminated an interest rate swap relating to $50 million of the $450 million of our fixed-rate debt and received approximately $4.5 million in cash. This transaction will be recorded in the third quarter of 2009.

Hedge Ineffectiveness

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

	Quarter Ended June 30,		**Six Months Ended June 30,**	
	2009	**2008**	**2009**	**2008**
	(In millions)			
Cash-flow hedges	**$ 23.5**	$ (44.7)	**$ 52.6**	$ (89.8)
Fair value hedges		6.4	**23.9**	12.9
Total	**$ 23.5**	$ (38.3)	**$ 76.5**	$ (76.9)

In addition, we did not recognize any gain or loss during the quarter or six months ended June 30, 2009 and 2008 relating to changes in value for the portion of our fair value hedges excluded from our hedge effectiveness assessment.

Mark-to-Market

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

our nonregulated retail gas customer supply activities, which are managed using economic hedges that we have not designated as cash-flow hedges in order to match the timing of recognition of the earnings impacts of those activities to the greatest extent permissible, and

economic hedges of activities that require accrual accounting for which the related hedge requires mark-to-market accounting.

Quantitative Information About Derivatives and Hedging Activities

Background

Effective January 1, 2009, we adopted SFAS No. 161, *Disclosures About Derivative Instruments and Hedging Activities,* (SFAS No. 161). SFAS No. 161 does not change the accounting for derivatives; rather, it requires expanded disclosure about derivative instruments and hedging activities regarding:

the ways in which an entity uses derivatives,

the accounting for derivatives and hedging activities, and

the impact that derivatives have (or could have) on an entity's financial position, financial performance, and cash flows.

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Balance Sheet Tables

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

The following table provides information about the types of market risks we manage using derivatives. This table only includes derivatives and does not reflect the price risks we are hedging that arise from physical assets or nonderivative accrual contracts within our generating plants, customer supply, and global commodities activities.

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

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

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

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As of June 30, 2009	Derivatives Designated as Hedging Instruments for Accounting Purposes		Derivatives Not Designated As Hedging Instruments for Accounting Purposes		All Derivatives Combined	
Contract type	**Asset Values[3]**	**Liability Values[4]**	**Asset Values[3]**	**Liability Values[4]**	**Asset Values[3]**	**Liability Values[4]**
			(In millions)			
Power contracts	$ 2,871.4	$ (4,146.8)	$ 24,500.4	$ (25,291.8)	$ 27,371.8	$ (29,438.6)
Gas contracts	2,215.4	(1,593.1)	8,602.6	(8,300.6)	10,818.0	(9,893.7)
Coal contracts	9.7	(123.5)	1,650.3	(1,679.6)	1,660.0	(1,803.1)
Other commodity contracts[1]	25.1	(19.4)	239.4	(201.7)	264.5	(221.1)
Interest rate contracts	40.4		43.2	(62.4)	83.6	(62.4)
Foreign exchange contracts		(5.9)	29.6	(12.7)	29.6	(18.6)
Total gross fair values	$ 5,162.0	$ (5,888.7)	$ 35,065.5	$ (35,548.8)	$ 40,227.5	$ (41,437.5)
Netting arrangements[5]					(39,093.8)	39,093.8
Cash collateral					(193.4)	133.4
Net fair values					$ 940.3	$ (2,210.3)
Net fair value by balance sheet line item:						
Accounts receivable[2]					$ (843.3)	
Derivative assets current					1,036.4	
Derivative assets noncurrent					747.2	
Derivative liabilities current						(1,272.8)
Derivative liabilities noncurrent						(937.5)
Total Derivatives					$ 940.3	$ (2,210.3)

1 Other commodity contracts include oil, freight, emission allowances, and weather contracts.

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

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

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

5 Represents the effect of legally enforceable master netting agreements.

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

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

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Gain and (Loss) Tables

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

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

The tables only include this information for derivatives and do not reflect the related gains or losses that arise from generation and generation-related assets, nonderivative accrual contracts, or NPNS contracts within our Generation, Customer Supply, and Global Commodities activities, other than fair value hedges, for which we separately show the gain or loss on the hedged asset or liability. As a result, for mark-to-market and cash-flow hedge derivatives, these tables only reflect the impact of derivatives themselves and therefore do not necessarily include all of the income statement impacts of the transactions for which derivatives are used to manage risk. For a more complete discussion of how derivatives affect our financial performance, see our accounting policy for Revenues, Fuel and Purchased Energy Expenses, and Derivatives and Hedging Activities in *Note 1* to our 2008 Annual Report on Form 10-K.

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

Cash Flow Hedges				***Quarter Ended June 30, 2009***		***Six Months Ended June 30, 2009***	
	Amount of Derivative Gain (Loss) Recorded in AOCI						
Contract type:	**Quarter Ended June 30, 2009**	**Six Months Ended June 30, 2009**	**Statement of Income (Loss) Line Item**	**Amount of Gain (Loss) Reclassified from AOCI into Earnings**	**Amount of Derivative Ineffectiveness Gain (Loss) Recorded in Earnings**	**Amount of Gain (Loss) Reclassified from AOCI into Earnings**	**Amount of Derivative Ineffectiveness Gain (Loss) Recorded in Earnings**
				(In millions)			
Hedges of forecasted sales:			Nonregulated revenues				
Power contracts	$ 100.4	$ 262.2		$ (37.5)	$ 21.2	$ (129.6)	$ 81.0
Gas contracts	7.9	(23.9)		(0.6)	4.5	(22.0)	6.5
Coal contracts		10.0				(229.9)	
Other commodity contracts[1]	(7.1)	6.6		(0.8)	(2.2)	(3.6)	(5.1)
Interest rate contracts		(0.3)		(0.2)		(0.2)	
Foreign exchange contracts		0.3				(0.9)	
Total gains (losses)	$ 101.2	$ 254.9		$ (39.1)	$ 23.5	$ (386.2)	$ 82.4

			Total included in nonregulated revenues				
Hedges of forecasted purchases:			Fuel and purchased energy expense				
Power contracts	$(112.8)	$ (886.8)		$ (611.9)	$ (0.3)	$ (1,038.4)	$ (29.5)
Gas contracts	(21.2)	154.5		66.7	1.9	92.7	2.6
Coal contracts	(40.5)	(125.1)		(52.0)	(1.6)	(65.3)	(2.9)
Other commodity contracts[2]	(3.7)	(2.1)		(2.7)		23.1	
Foreign exchange contracts		0.1				0.1	
Total gains (losses)	$(178.2)	$ (859.4)	Total included in fuel and purchased energy expense	$ (599.9)	$	$ (987.8)	$ (29.8)
Hedges of interest rates:			Interest expense				
Interest rate contracts				(0.1)		(0.2)	
Total gains (losses)	$	$	Total included in interest expense	$ (0.1)	$	$ (0.2)	$
Grand total gains (losses)	$ (77.0)	$ (604.5)		$ (639.1)	$ 23.5	$ (1,374.2)	$ 52.6

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

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The following table presents gains and losses on derivatives designated as fair value hedges and, separately, the gains and losses on the hedged item. As discussed earlier, we record the unrealized gains and losses on fair value hedges as well as changes in the fair value of the hedged asset or liability in earnings as they occur. The difference between these amounts represents hedge ineffectiveness. Due to the sale of our Houston-based gas trading operation, we do not have any second quarter activity under fair value hedges related to gas contracts.

Fair Value Hedges		*Quarter Ended June 30, 2009*		*Six Months Ended June 30, 2009*	
Contract type:	**Statement of Income (Loss) Line Item**	**Amount of Gain (Loss) Recognized in Income on Derivative**	**Amount of Gain (Loss) Recognized in Income on Hedged Item**	**Amount of Gain (Loss) Recognized in Income on Derivative**	**Amount of Gain (Loss) Recognized in Income on Hedged Item**
			(In millions)		
Commodity contracts:					
Gas contracts	Nonregulated revenues	$	$	$ 40.6	$ (16.7)
Interest rate contracts	Interest expense	(20.4)	20.4	(15.5)	15.5
Total gains (losses)		$ (20.4)	$ 20.4	$ 25.1	$ (1.2)

The following table presents gains and losses on mark-to-market derivatives, contracts that have not been designated as hedges for accounting purposes. As discussed more fully in *Note 1* to our 2008 Annual Report on Form 10-K, we record the unrealized gains and losses on mark-to-market derivatives in earnings as they occur. While we use mark-to-market accounting for risk management and trading activities because changes in fair value more closely reflect the economic performance of the activity, we also use mark-to-market accounting for certain derivatives related to portions of our physical energy delivery activities. Accordingly, the total amount of gains and losses from mark-to-market derivatives does not necessarily reflect the total economics of related transactions.

Mark-to-Market Derivatives		*Quarter Ended June 30, 2009*	*Six Months Ended June 30, 2009*
Contract type:	**Statement of Income (Loss) Line Item**	**Amount of Gain (Loss) Recorded in Income on Derivative**	**Amount of Gain (Loss) Recorded in Income on Derivative**
		(In millions)	
Commodity contracts:			
Power contracts	Nonregulated revenues	$ 58.4	$ 147.0
Gas contracts	Nonregulated revenues	(116.9)	(279.5)
Coal contracts	Nonregulated revenues	52.1	9.8
Other commodity contracts[1]	Nonregulated revenues	4.3	0.4
Coal contracts	Fuel and purchased energy expense	(2.2)	(107.7)
Interest rate contracts	Nonregulated revenues	(20.1)	(20.6)
Foreign exchange contracts	Nonregulated revenues	1.9	9.7
Total gains (losses)		$ (22.5)	$ (240.9)

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

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

Volume of Derivative Activity

The volume of our derivatives activity is directly related to the fundamental nature and scope of our business and the risks we manage. We own or control electric generating

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facilities, which exposes us to both power and fuel price risk; we serve electric and gas wholesale and retail customers within our customer supply business, which exposes us to electricity and natural gas price risk; and we provide risk management services and engage in trading activities, which can expose us to a variety of commodity price risks. We conduct our business activities throughout the United States and internationally. In order to manage the risks associated with these activities, we are required to be an active participant in the energy markets, and we routinely employ derivative instruments to conduct our business.

Derivative instruments provide an efficient and effective way to conduct our business and to manage the associated risks. We manage our generating resources and customer supply activities based upon established policies and limits, and we use derivatives to establish a portion of our hedges and to adjust the level of our hedges from time to time. Additionally, we engage in trading activities which enable us to execute hedging transactions in a cost-effective manner. We manage those activities based upon various risk measures, including position limits, economic value at risk (EVaR) and value at risk (VaR), and we use derivatives to establish and maintain those activities within the prescribed limits. We are also using derivatives to execute, control, and reduce the overall level of our trading positions and risk as well as to manage a portion of our interest rate risk associated with debt and our foreign currency risk from non-dollar denominated transactions. Accordingly, the use of derivative instruments is integral to the conduct of our business, and derivative instruments are an important tool through which we are able to manage and mitigate the risks that are inherent in our activities.

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

First, the volume information is not a complete representation of our market price risk because it only includes derivative contracts. Accordingly, this table does not present a complete picture of our overall net economic exposure, and should not be interpreted as an indication of open or unhedged commodity positions, because the use of derivatives is only one of the means by which we engage in and manage the risks of our business. For example, the table does not include power or fuel quantities and risks arising from our physical assets, non-derivative contracts, and forecasted transactions that we manage using derivatives; a portion of these volumes reduce those risks. It also does not include volumes of commodities under nonderivative contracts that we use to serve customers or manage our risks. Our actual net economic exposure from our generating facilities and customer supply activities is reduced by derivatives, and the exposure from our trading activities is managed and controlled through the risk measures discussed above. Therefore, the information in the table below is only an indication of that portion of our business that we manage through derivatives and serves primarily to identify the extent of our derivatives activities and the types of risks that they are intended to manage.

Additionally, the disclosure of derivative quantities potentially could reveal commercially valuable or otherwise competitively sensitive information that could limit the effectiveness and profitability of our business activities. Therefore, in the table below, we have computed the derivative volumes for commodities by aggregating the absolute value of net open long (purchase) and short (sell) positions within commodities for each year. This provides an indication of the level of derivatives activity, but it does not indicate either the direction of our position (long or short), or the overall size of our position. We believe this presentation gives an appropriate indication of the level of derivatives activity without unnecessarily revealing the size and direction of our derivatives positions.

Finally, the volume information for commodity derivatives represents "delta equivalent" quantities, not gross notional amounts. We make use of different types of commodity derivative instruments such as forwards, futures, options, and swaps, and we believe that the delta equivalent quantity is the most relevant measure of the volume associated with these commodity derivatives. The delta-equivalent quantity represents a risk-adjusted notional quantity for each contract that takes into account the probability that an option will be exercised. Therefore, the volume information for commodity derivatives represents the delta equivalent quantity of those contracts, computed on the basis described above. For interest rate contracts and foreign currency contracts we have presented the notional amounts of such contracts in the table below.

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The following table presents the volume of our derivative activities as of June 30, 2009, shown by contractual settlement year.

Quantities[1] Under Derivative Contracts ***As of June 30, 2009***

Contract Type (Unit)	**2009**	**2010**	**2011**	**2012**	**2013**	**Thereafter**	**Total**
				(In millions)			
Power (MWh)	21.6	23.6	8.3	4.9		3.7	62.1
Gas (MMBTU)	30.6	15.1	14.7	15.8	5.5	43.2	124.9
Coal (Tons)	3.9	4.7	0.9	0.4			9.9
Oil (BBL)	0.2	0.1					0.3
Emission Allowances (Tons)	5.5	0.2					5.7
Interest Rate Contracts	$1,534.3	$516.4	$238.6	$486.5	$93.2	$ 325.0	$3,194.0
Foreign Exchange Rate Contracts	$ 6.7	$ 37.0	$ 24.5	$ 16.7	$16.7	$ 32.3	$ 133.9

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

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

Credit-Risk Related Contingent Features

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

The following table presents information related to these derivatives. Based on contractual provisions, we estimate that if Constellation Energy's senior unsecured debt were downgraded, our total contingent collateral obligation for derivatives in a net liability position was $0.3 billion as of June 30, 2009, which represents the additional collateral that we could be required to post with counterparties, including both cash collateral and letters of credit, in the event of a credit downgrade to below investment grade. These amounts are associated with net derivative liabilities totaling $1.5 billion after reflecting legally binding master netting agreements and collateral already posted.

Interpretations of SFAS No. 161 indicate that the gross fair value of derivatives in a net liability position that have credit-risk-related contingent features should be disclosed, and we present this amount in the first column in the table below. This gross fair value amount represents only the out-of-the-money contracts containing such features that are not fully collateralized by cash on a stand-alone basis. Thus, this amount does not reflect the offsetting fair value of in-the-money contracts under legally-binding master netting agreements with the same counterparty, as shown in the second column in the table. These in-the-money contracts would offset the amount of any gross liability that could be required to be collateralized, and as a result, the actual potential collateral requirements would be based upon the net fair value of derivatives containing such features, not the gross amount. The amount of any possible contingent collateral for such contracts in the event of a downgrade would be further reduced to the extent that we have already posted collateral related to the net liability.

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

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Credit-Risk Related Contingent Feature *As of June 30, 2009*

Gross Fair Value of Derivative Contracts Containing This Feature[1]	Offsetting Fair Value of In-the-Money Contracts Under Master Netting Agreements[2]	Net Fair Value of Derivative Contracts Containing This Feature[3]	Amount of Posted Collateral[4]	Contingent Collateral Obligation[5]
		(In billions)		
$ 18.1	$ (16.6)	$ 1.5	$ 1.0	$ 0.3

1 Amount represents the gross fair value of out-of-the-money derivative contracts containing credit-risk-related contingent features that are not fully collateralized by posted cash collateral on an individual, contract-by-contract basis ignoring the effects of master netting agreements.
2 Amount represents the offsetting fair value of in-the-money derivative contracts under legally-enforceable master netting agreements with the same counterparty, which reduces the amount of any liability for which we potentially could be required to post collateral.
3 Amount represents the net fair value of out-of-the-money derivative contracts containing credit-risk related contingent features after considering the mitigating effects of offsetting positions under master netting arrangements and reflects the actual net liability upon which any potential contingent collateral obligations would be based.
4 Amount includes cash collateral posted of $133.4 million and letters of credit of $882.1 million.
5 Amounts represent the additional collateral that we could be required to post with counterparties, including both cash collateral and letters of credit, in the event of a credit downgrade to below investment grade after giving consideration to offsetting derivative and non-derivative positions under master netting agreements.

Concentrations of Derivative-Related Credit Risk

Constellation Energy's wholesale and retail credit risk management policies establish the guidelines under which we extend unsecured credit to counterparties and customers. Based on the counterparty analysis and limits established by Constellation Energy, collateral or other security may be required to enter into transactions based on the potential exposure. Under most agreements we have entered into, collateral is in the form of cash or letters of credit. These forms of collateral are held by us and can be drawn upon should a counterparty default on its obligations under its agreement.

As a best practice, we enter into commodity master agreements and cross-commodity netting agreements in order to achieve the benefits of netting in terms of exposure and collateral capital reductions. Where beneficial to the risk profile of the company, we will seek credit protections that include upfront collateral, margining, material adverse change clauses (based on credit ratings downgrades or other financial ratios events), and adequate assurances clauses in our master agreements that can be utilized to request security from our counterparties in order to cover our potential risk of loss.

We consider a significant concentration of credit risk to be any single obligor or counterparty whose concentration exceeds 10% of total credit exposure. As of June 30, 2009, no single counterparty concentration comprises more than 10% of the total exposure of the portfolio, and no collection of counterparties based in a single country other than the United States comprises more than 10% of the total exposure of the portfolio.

Fair Value Measurements

SFAS No. 157, *Fair Value Measurements*, (SFAS No. 157) defines fair value, establishes a framework for measuring fair value, and requires certain disclosures about fair value measurements. Fair value is the price that we would receive to sell an asset or pay to transfer a liability in an orderly transaction between market participants at the measurement date (exit price).

SFAS No. 157 also creates a fair value hierarchy that prioritizes the inputs used to measure fair value. The three levels of the fair value hierarchy are as follows:

Level 1 Unadjusted quoted prices available in active markets at the measurement date for identical assets or liabilities.

Level 2 Pricing inputs, other than quoted prices included within Level 1, which are either directly or indirectly observable as of the reporting date.

Level 3 Significant inputs that are generally not observable from market activity.

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

We classify assets and liabilities within the fair value hierarchy based on the lowest level of input that is

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

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

Recurring Measurements

BGE's assets and liabilities measured at fair value on a recurring basis are immaterial. Our merchant energy business segment's assets and liabilities measured at fair value on a recurring basis consist of the following:

	As of June 30, 2009	
	Assets	**Liabilities**
	(In millions)	
Cash equivalents	$ 746.3	$
Debt and equity securities	1,111.4	
Derivative instruments:		
Classified as derivative assets and liabilities:		
Current	1,036.4	(1,272.8)
Noncurrent	747.2	(937.5)
Total classified as derivative assets and liabilities	1,783.6	(2,210.3)
Classified as accounts receivable*	(843.3)	
Total derivative instruments	940.3	(2,210.3)
Total recurring fair value measurements	$ 2,798.0	$ (2,210.3)

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

Cash equivalents represent money market mutual funds which are included in "Cash and cash equivalents" and "Nuclear decommissioning trust funds" in the Consolidated Balance Sheets. Debt and equity securities primarily represent available-for-sale investments which are included in "Nuclear decommissioning trust funds" and "Other assets" in the Consolidated Balance Sheets. Derivative instruments represent unrealized amounts related to all derivative positions, including futures, forwards, swaps, and options. We classify exchange-listed contracts as part of "Accounts Receivable" in our Consolidated Balance Sheets. We classify the remainder of our derivative contracts as "Derivative assets" or "Derivative liabilities" in our Consolidated Balance Sheets.

The table below disaggregates our net derivative assets and liabilities on a gross contract-by-contract basis. Each individual asset or liability that is remeasured at fair value on a recurring basis is required to be presented in this table and classified, in its entirety, within the appropriate level in the fair value hierarchy. Therefore, the objective of this table is to provide information about how each individual derivative contract is valued within the fair value hierarchy, regardless of whether a particular contract is eligible for netting against other contracts or whether it has been collateralized.

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The table below sets forth by level within the fair value hierarchy the gross components of the Company's assets and liabilities that were measured at fair value on a recurring basis as of June 30, 2009. These gross balances are intended solely to provide information on sources of inputs to fair value and proportions of fair value involving objective versus subjective valuations and do not represent either our actual credit exposure or net economic exposure.

At June 30, 2009	**Level 1**	**Level 2**	**Level 3**	**Netting and Cash Collateral***	**Total Net Fair Value**
			(In millions)		
Cash equivalents	$ 734.0	$ 12.3	$	$	$ 746.3
Debt and equity securities:					
Marketable equity securities	266.3				266.3
Mutual funds / common collective trusts	48.4	505.6			554.0
Corporate debt securities		178.0			178.0
U.S. Agencies		44.6			44.6
U.S. Treasuries	20.4				20.4
State municipal bonds		48.1			48.1
Debt and equity securities	335.1	776.3			1,111.4
Derivative assets	180.9	36,104.9	3,941.7	(39,287.2)	940.3
Derivative liabilities	(160.5)	(37,158.8)	(4,118.2)	39,227.2	(2,210.3)
Net derivative position	20.4	(1,053.9)	(176.5)	(60.0)	(1,270.0)
Total	$ 1,089.5	$ (265.3)	$ (176.5)	$ (60.0)	$ 587.7

** We present our derivative assets and liabilities in our Consolidated Balance Sheets on a net basis. We net derivative assets and liabilities, including cash collateral, when a legally enforceable master netting agreement exists between us and the counterparty to a derivative contract. At June 30, 2009, we included $193.4 million of cash collateral held and $133.4 million of cash collateral posted (excluding margin posted on exchange traded derivatives) in netting amounts in the above table.*

The factors that cause changes in the gross components of the derivatives amounts in the table above are unrelated to the existence or level of actual market or credit risk from our operations. Thus, the gross components of the derivatives amounts in this table decreased from the corresponding amounts as of December 31, 2008, due to substantial changes in commodity prices and the decrease in the number of derivative contracts outstanding. We describe the primary factors that change the gross components below.

SFAS No. 157 requires us to prepare this table by separating each individual derivative contract that is in the money from each contract that is out of the money. It also requires us to ignore master netting agreements and collateral for our derivatives. As a result, the gross "asset" and "liability" amounts under each of the three fair value levels far exceed our actual economic exposure to commodity price risk and credit risk. Our actual economic exposure consists of the net derivative position combined with our nonderivative accrual contracts, such as those for load-serving, and our physical assets, such as our power plants. Our actual credit risk exposure is reflected in the net derivative asset and derivative liability amounts shown in the Total Net Fair Value column.

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

Cash equivalents are primarily comprised of exchange traded money market funds and money market mutual funds. These instruments are valued based upon unadjusted quoted prices in active markets and are classified within Level 1. Cash equivalents classified in Level 2 are held within our nuclear decommissioning trust funds and are valued based on fund share price, which is observable on a less frequent basis.

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Debt and equity securities include trust assets securing certain executive benefits, other marketable securities, and our nuclear decommissioning trust funds. Trust assets securing certain executive benefits consist of mutual funds, which are valued based upon unadjusted quoted prices in active markets and are classified within Level 1. Our other marketable securities consist of marketable equity securities, which are valued based on unadjusted quoted prices in active markets and are classified within Level 1. Nuclear decommissioning trust funds consist of a number of different types of securities, including the following:

- marketable equity securities, mutual funds, and United States Treasury securities are classified within Level 1 because they are valued based on unadjusted quoted prices in active markets,
- fixed income securities other than United States Treasury securities are classified within Level 2 because these instruments are traded in markets that are less active than the markets for equity securities and United States Treasury securities, and
- common collective trusts are classified within Level 2 because they are valued based on the fund share price, which is observable on a less frequent basis.

Derivative instruments include exchange-traded and bilateral contracts. Exchange-traded derivative contracts include futures and certain options. Bilateral derivative contracts include swaps, forwards, certain options and complex structured transactions. We utilize models to measure the fair value of bilateral derivative contracts. Generally, we use similar models to value similar instruments. Valuation models utilize various inputs, which include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, other observable inputs for the asset or liability, and market-corroborated inputs, which are inputs derived principally from or corroborated by observable market data by correlation or other means. However, the primary input to our valuation models is the forward commodity price. We have classified derivative contracts within the fair value hierarchy as follows:

- Exchange-traded derivative contracts valued based on unadjusted quoted prices in active markets are classified within Level 1.
- Exchange-traded derivative contracts valued using pricing inputs based upon market quotes or market transactions are classified within Level 2. These contracts generally trade in less active markets due to the length of the contracts (i.e., for certain contracts the exchange sets the closing price, which may not be reflective of an actual trade).
- Bilateral derivative contracts where observable inputs are available for substantially the full term and value of the asset or liability are classified within Level 2.
- Bilateral derivative contracts with a lower availability of pricing information are classified in Level 3. In addition, complex or structured transactions, such as certain options, may require us to use internally-developed model inputs, which might not be observable in or corroborated by the market, to determine fair value. When such unobservable inputs have more than an insignificant impact on the measurement of fair value, we also classify the instrument within Level 3.

In order to determine fair value, we utilize various inputs and factors including market data and assumptions that market participants would use in pricing assets or liabilities as well as assumptions about the risks inherent in the inputs to the valuation technique. The inputs and factors include:

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

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The following table sets forth a reconciliation of changes in Level 3 fair value measurements:

	Quarter Ended June 30, 2009	Quarter Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
	(In millions)			
Balance at beginning of period	**$ (275.1)**	$ 400.4	**$ 37.0**	$ (147.1)
Realized and unrealized (losses) gains:				
Recorded in income	**(99.8)**	181.0	**(247.2)**	165.9
Recorded in other comprehensive income	**114.6**	74.6	**23.9**	250.5
Purchases, sales, issuances, and settlements	**34.6**	5.2	**36.5**	36.3
Transfers into and out of Level 3	**49.2**	(449.8)	**(26.7)**	(94.2)
Balance at end of period	**$ (176.5)**	$ 211.4	**$ (176.5)**	$ 211.4
Change in unrealized gains recorded in income relating to derivatives still held at end of period	**$ 71.0**	$ 247.6	**$ 99.6**	$ 246.0

Realized and unrealized gains (losses) are included primarily in "Nonregulated revenues" for our derivative contracts that are marked-to-market in our Consolidated Statements of Income (Loss) and are included in "Accumulated other comprehensive loss" for our derivative contracts designated as cash-flow hedges in our Consolidated Balance Sheets.

Fair Value of Financial Instruments

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

At June 30, 2009	Carrying Amount	Fair Value
	(In millions)	
Investments and other assets Constellation Energy	**$ 1,253.6**	**$ 1,253.5**
Fixed-rate long-term debt:		
Constellation Energy (including BGE)	**5,974.3**	**5,794.1**
BGE	**2,238.5**	**2,177.0**
Variable-rate long-term debt:		
Constellation Energy (including BGE)	**677.4**	**677.4**

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

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

Accounting Standards Issued

SFAS No. 167

In June 2009, the FASB issued SFAS No. 167, *Amendments to FASB Interpretation No. 46R*, which is effective for interim and annual reporting periods beginning after November 15, 2009. The standard includes the following significant provisions:

- requires an entity to qualitatively assess the determination of the primary beneficiary of a VIE based on whether the entity (1) has the power to direct matters that most significantly impact the activities of the VIE, and (2) has the obligation to absorb losses or the right to receive benefits of the VIE that could potentially be significant to the VIE,
- requires an ongoing reconsideration of the primary beneficiary instead of only upon certain triggering events,

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- amends the events that trigger a reassessment of whether an entity is a VIE, and

- for an entity that is the primary beneficiary of a VIE, requires separate balance sheet presentation of (1) the assets of the consolidated VIE, if they can be used to only settle specific obligations of the consolidated VIE, and (2) the liabilities of a consolidated VIE for which creditors do not have recourse to the general credit of the primary beneficiary.

We are currently evaluating the impacts of this standard on our, and BGE's, financial results, which could be material.

SFAS No. 168

In June 2009, the FASB issued SFAS No. 168, *The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles*, which is effective for financial statements issued for interim and annual periods ending after September 15, 2009. The FASB Accounting Standards Codification (Codification) will become the sole source of authoritative generally accepted accounting principles in the United States of America (GAAP) and will supersede all existing non-SEC accounting and reporting standards. Once the Codification is in effect, all of its content will carry the same level of authority, and any accounting guidance not contained within the Codification will become non-authoritative. Because the Codification is not intended to change GAAP, the adoption of this standard will not have an impact on our, or BGE's, financial results. However, our disclosures and references to accounting standards will change to reflect the new Codification structure beginning with our Form 10-Q for the quarter ending September 30, 2009.

Accounting Standards Adopted

SFAS No. 160

In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements, an amendment of ARB No. 51*. SFAS No. 160 provides that a noncontrolling interest in a subsidiary is an ownership interest in the consolidated entity that should be reported as equity in the consolidated financial statements. This presentation is based upon the view of the consolidated business as a single economic entity and considers minority ownership interests in consolidated subsidiaries as equity in the consolidated entity.

SFAS No. 160 requires that companies:

- present noncontrolling interests (formerly described as "minority interests") in the consolidated balance sheet as a separate line item within equity,

- separately present on the face of the income statement the amount of consolidated net income attributable to the parent and to the noncontrolling interest,

- account for changes in ownership interests that do not result in a change in control as equity transactions, and

- upon deconsolidation of a subsidiary due to a change in control, measure any retained interest at fair value and record a gain or loss for both the portion sold and the portion retained.

Effective January 1, 2009, we presented and disclosed noncontrolling interests in our Consolidated Financial Statements in accordance with SFAS No. 160.

The total change in Constellation Energy's noncontrolling interest amount of $25.8 million is primarily due to income earned at one entity in which we have a noncontrolling interest.

The total change in BGE's noncontrolling interest amount of $8.1 million is primarily due to a contribution by its noncontrolling interest owner.

SFAS No. 161

In March 2008, the FASB issued SFAS No. 161. SFAS No. 161 requires entities to provide expanded disclosure about derivative instruments and hedging activities, but does not change the accounting for derivatives. We adopted SFAS No. 161 on January 1, 2009 and provide these additional disclosures beginning on page 29.

SFAS No. 165

In May 2009, the FASB issued SFAS No. 165, *Subsequent Events*, which establishes the general standards of accounting for and disclosure of events that occur subsequent to the balance sheet date but before financial statements are issued or are available to be issued. Because this standard does not change the fundamental requirements for accounting for subsequent events, it does not have a significant impact on our, or BGE's financial results. However, this standard does require the disclosure of the date through which subsequent events have been evaluated as well as whether that date is the date the financial statements were issued. We adopted SFAS No. 165 as of June 30, 2009 and have provided the additional required disclosures on page 11.

FSP SFAS No. 115-2 and SFAS No. 124-2

In April 2009, the FASB issued Staff Position (FSP) SFAS No. 115-2 and SFAS No. 124-2, *Recognition and Presentation of Other-Than-Temporary Impairments*, which amends the other-than-temporary guidance for debt securities and expands the disclosure requirements for debt and equity securities. The available-for-sale investments in our nuclear decommissioning trust funds are managed by third parties who have independent discretion over the purchases and sales of securities. As such, the amended guidance for other-than-temporary impairments will not affect our policy of recognizing impairments for any of these investments for which fair value declines below its book value. The FSP also requires disclosures regarding available-for-sale securities in interim financial statements as well as in annual financial statements. We adopted FSP SFAS No. 115-2 and SFAS No. 124-2 as of April 1, 2009 and provide the additional disclosures regarding available for sale securities beginning on page 17.

FSP SFAS No. 107-1 and APB No. 28-1

In April 2009, the FASB issued FSP SFAS No. 107-1 and APB No. 28-1, *Interim Disclosures about Fair Value of Financial Instruments*, which amends SFAS No. 107 to require disclosures about fair value of financial instruments in interim financial statements as well as in annual financial statements. We adopted FSP SFAS No. 107-1 and APB No. 28-1 as of April 1, 2009 with no effect on our, or BGE's financial results. We provide the disclosures regarding fair value of financial instruments on page 40.

FSP SFAS No. 157-2

In February 2008, the FASB issued FSP SFAS No. 157-2, *Effective Date of FASB Statement No. 157*. FSP SFAS No. 157-2 delayed the effective date of SFAS No. 157 for many nonfinancial assets and liabilities, including asset retirement obligations, long-lived assets, and goodwill, to fiscal years beginning after November 15, 2008. Prospectively, we will disclose subsequent measurements of nonfinancial assets and liabilities at fair value as part of our SFAS No. 157 footnote. We adopted FSP SFAS No. 157-2 on January 1, 2009 with no effect on our, or BGE's, financial results. See page 36 for our disclosures about fair value measurements.

FSP SFAS No. 157-4

In April 2009, the FASB issued FSP SFAS No. 157-4, *Determining Fair Value When the Volume and Level of Activity for the Asset or Liability have Significantly Decreased and Identifying Transactions That Are Not Orderly*, which provides additional guidance for estimating fair value when the volume and level of activity for the asset or liability have decreased. The FSP also includes guidance on identifying circumstances that indicate a transaction is not orderly. Finally, the FSP expands the disclosure requirements for fair value measurements to include further disaggregation in the tabular disclosures. We adopted FSP SFAS No. 157-4 as of April 1, 2009 with no effect on our, or BGE's, financial results. See page 36 for our disclosures about fair value measurements.

EITF No. 08-5

In September 2008, the FASB ratified EITF No. 08-5, *Third Party Credit Enhancements*. EITF No. 08-5 clarifies that an entity shall not include the effects of a third party credit enhancement in the fair value measurement of a liability. We adopted EITF No. 08-5 on January 1, 2009 and recorded a reduction in our derivative liability of approximately $4 million.

Related Party Transactions

BGE Income Statement

BGE is obligated to provide market-based standard offer service to all of its electric customers for varying periods. Bidding to supply BGE's market-based standard offer service to electric customers will occur from time to time through a competitive bidding process approved by the Maryland PSC.

Our merchant energy business will supply a portion of BGE's market-based standard offer service obligation to electric customers through September 30, 2011.

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

	Quarter Ended June 30,		Six Months Ended June 30,	
	2009	**2008**	**2009**	**2008**
	(In millions)			
Purchased energy	**$ 142.5**	$ 186.0	**$ 346.8**	$ 457.3

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

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

	Quarter Ended June 30,		Six Months Ended June 30,	
	2009	**2008**	**2009**	**2008**
	(In millions)			
Charges to BGE	**$ 35.5**	$ 35.0	**$ 65.1**	$ 70.1

BGE 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. Under this arrangement, BGE had invested $154.0 million at June 30, 2009 and had invested $148.8 million at December 31, 2008.

BGE's Consolidated Balance Sheets include intercompany amounts related to BGE's purchases to meet its standard offer service obligation, BGE's gas purchases, BGE's charges to Constellation Energy and its nonregulated affiliates for certain services it provides them, Constellation Energy and its nonregulated affiliates' charges to BGE for certain services provided to BGE, and the participation of BGE's employees in the Constellation Energy defined benefit plans.

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

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Item 2. Management's Discussion

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

Introduction and Overview

Constellation Energy Group, Inc. (Constellation Energy) is an energy company that 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* beginning on page 18.

This Quarterly Report on Form 10-Q is a combined report of Constellation Energy and BGE. References in this report to "we" and "our" are to Constellation Energy and its subsidiaries, collectively. References in this report to the "regulated business(es)" are to BGE. We discuss our business and strategy in more detail in *Item 1 Business* section of our 2008 Annual Report on Form 10-K and we discuss the risks affecting our business in *Item 1A. Risk Factors* section of our 2008 Annual Report on Form 10-K.

Our 2008 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 recent events, regulation, weather, and other factors affect our business, and
- *Critical Accounting Policies* section.

Critical accounting policies are the accounting policies that are most important to the portrayal of our financial condition and results of operations and that require management's most difficult, subjective, or complex judgment. Our critical accounting policies include derivative accounting, 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,
- expected sources of cash for future capital expenditures, and
- our net available liquidity and collateral requirements.

As you read this discussion and analysis, refer to our Consolidated Statements of Income (Loss) on page 3, which present the results of our operations for the quarters and six months ended June 30, 2009 and 2008. We analyze and explain the differences between periods in the specific line items of the Consolidated Statements of Income (Loss).

We have organized our discussion and analysis as follows:

We describe changes to our business environment during the year.

We highlight significant events that occurred in 2009 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

Various factors affect our financial results. We discuss these various factors in the *Forward Looking Statements* section on page 75 and in *Item 1A. Risk Factors* section of our 2008 Annual Report on Form 10-K. We discuss our market risks in the *Risk Management* section beginning on page 70.

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

In this section, we discuss in more detail events which have impacted our business during 2009.

Federal Regulation

The United States Congress and the Commodity Futures Trading Commission are evaluating additional regulations for the derivatives markets, including position limits and eliminating hedge regulatory exemptions. We are unable to determine the final form any regulations may take, but such regulations could have a material effect on our business.

Maryland PSC Review of EDF Transaction

In June 2009, the Maryland Public Service Commission (Maryland PSC) determined that EDF Group and related entities (EDF) would obtain the power to exercise substantial influence over the policies and actions of BGE under Constellation Energy's proposed transaction with EDF, and, therefore, that the Maryland PSC must review the transaction to determine that it is in the public interest with benefits and no harm to consumers. EDF has filed an application with the Maryland PSC to commence the Maryland PSC's review and a decision is expected in mid-October 2009. In addition, Constellation Energy, BGE and EDF filed suit in the Baltimore City Circuit Court appealing the Maryland PSC's decision, which was dismissed by the court. Constellation Energy and BGE have appealed the court's decision.

We cannot predict the outcome of the Maryland PSC or court proceedings. A delay in obtaining the required review or the imposition of unfavorable terms or conditions in connection with such review could affect our ability to complete the transaction with EDF and could have a negative impact on our credit ratings and financial results.

Environmental Matters

Air Quality

Capital Expenditures

As discussed in our 2008 Annual Report on Form 10-K, we expect to incur additional environmental capital expenditures to comply with air quality laws and regulations. Based on updated information from vendors, we expect our estimated environmental capital requirements for these air quality projects to be approximately $325 million in 2009, $25 million in 2010, $5 million in 2011 and $30 million from 2012-2013.

Our estimates may change further as we implement our compliance plan. As discussed in our 2008 Annual Report on Form 10-K, our estimates of capital expenditures continue to be subject to significant uncertainties.

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 40.

Events of 2009

Divestitures

In January 2009, we entered into a definitive agreement to sell a majority of our international commodities operation. We completed this transaction in March 2009.

In February 2009, we entered into a definitive agreement to sell our gas trading operation. We transferred control of this operation in April 2009. Simultaneously, we entered into an agreement with the buyer of our Houston-based gas trading operation under which that company will provide us with the gas supply needed to support our retail gas customer supply business.

In June 2009, we completed the sale of a uranium market participant that provides marketing services to uranium producers, utilities and an investment fund in the North American and European markets.

We discuss these divestitures and the gas supply agreement in more detail in the *Notes to Consolidated Financial Statements* beginning on page 15.

Merger Termination and Strategic Alternatives Costs

During the quarter and six months ended June 30, 2009, we incurred merger termination and strategic alternatives costs related to the terminated merger with MidAmerican Energy Holdings Company (MidAmerican), the conversion of our Series A Preferred Stock, the transactions related to EDF, and other strategic alternatives costs. We discuss costs related to the mergers and strategic alternatives in more detail on page 11 in

Notes to Consolidated Financial Statements.

Impairment Losses and Other Costs

During the quarter and six months ended June 30, 2009, we recorded impairment losses and other costs on certain of our equity method investments, investments in equity securities and other assets. We discuss these charges in more detail in the *Notes to Consolidated Financial Statements* beginning on page 13.

Workforce Reduction Costs

During the six months ended June 30, 2009, we incurred workforce reduction costs primarily related to the divestiture of a majority of our international commodities operation as well as some smaller restructurings elsewhere in our organization. We recognized an $11.2 million pre-tax charge in 2009 related to the elimination of approximately 180 positions. We expect all of these restructurings will be completed within the next 12 months. We discuss our workforce reduction costs in more detail in the *Notes to Consolidated Financial Statements* beginning on page 14.

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Results of Operations for the Quarter and Six Months Ended June 30, 2009
Compared with the Same Periods of 2008

In this section, we discuss our earnings and the factors affecting them. We begin with a general overview, then separately discuss earnings for our operating segments. Significant changes in other income and expense, fixed charges, and income taxes are discussed, as necessary, in the aggregate for all segments in the *Consolidated Nonoperating Income and Expenses* section on page 61.

Overview

Results

	Quarter Ended June 30,		Six Months Ended June 30,	
	2009	**2008**	**2009**	**2008**
		(In millions, after-tax)		
Merchant energy	**$ 20.9**	$ 280.0	**$ (181.8)**	$ 352.7
Regulated electric	**22.1**	(101.7)	**67.5**	(65.5)
Regulated gas	**(6.2)**	(2.3)	**33.4**	37.9
Other nonregulated	**(8.5)**	(1.0)	**(10.5)**	(0.7)
Net Income (Loss)	**$ 28.3**	$ 175.0	**$ (91.4)**	$ 324.4
Net Income (Loss) attributable to common stock	**$ 8.1**	$ 171.5	**$ (115.4)**	$ 317.2
Change from prior year	**$ (163.4)**		**$ (432.6)**	
Other Items Included in Operations (after-tax)[1]:				
International commodities operation and gas trading operation[2]	**$ (123.8)**	$	**$ (308.0)**	$
Impairment losses and other costs	**(65.4)**		**(76.6)**	
Impairment of nuclear decommissioning trust assets	**(6.1)**	(2.4)	**(29.8)**	(6.3)
Merger termination and strategic alternatives costs	**(4.0)**		**(46.3)**	
Accrual of Maryland settlement credit		(125.3)		(125.3)
BGE effective tax rate impact of Maryland settlement agreement		2.1		8.7
Non-qualifying hedges		(34.7)		(69.3)
Workforce reduction costs	**(1.1)**		**(5.3)**	
Credit facility amendment fees	**(5.2)**		**(8.9)**	

Total Other Items	**$ (205.6)**	$ (160.3)	**$ (474.9)**	$ (192.2)
Change from prior year	**$ (45.3)**		**$ (282.7)**	

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

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

Quarter and Six Months Ended June 30, 2009

Our total net income (loss) attributable to common stock for the quarter and six months ended June 30, 2009 was unfavorable compared to net income attributable to common stock for the same periods of 2008 primarily due to the following:

	Quarter Ended June 30,	Six Months Ended June 30,
	2009 vs. 2008	
	(In millions, after-tax)	
Generation gross margin	$ 66	$ 73
Customer supply gross margin	(26)	12
Global Commodities gross margin	(253)	(401)
Hedge ineffectiveness	45	96
Absence of sale of upstream gas assets	(46)	(55)
Credit loss coal supplier bankruptcy		33
Emissions allowance write-down	13	13
Merchant interest expense	(25)	(53)
Regulated businesses, primarily related to absence of Maryland settlement agreement credit	120	129
Other nonregulated businesses	(9)	(11)
Total change in Other Items included in operations per *Overview Results* table	(45)	(283)
All other changes	(3)	14
Total Change	$ (163)	$ (433)

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 2008 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 customer supply activities, and uses our portfolio management and trading capabilities both to manage risk and to deploy risk capital.

Earlier this year, we outlined various strategic initiatives for our Global Commodities operation. We discuss our strategy in more detail in the *Strategy* section of our 2008 Annual Report on Form 10-K. As of the end of the second quarter of 2009, these initiatives are substantially complete, with the balance to be completed by year-end.

While we have completed the sale of a majority of our international commodities operation, our gas trading

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operation, certain other trading operations, and a uranium market participant, the execution of our strategy in the future will be affected by continued uncertainty in global financial, credit, and commodities markets. Execution of our goals could have a substantial effect on the nature and mix of our business activities. In particular, upon closing the transactions contemplated by our Investment Agreement with EDF, we expect that our subsidiary that owns our nuclear generation assets will be deconsolidated. In turn, this could affect our financial position, results of operations, and cash flows in material amounts, and these amounts could vary substantially from historical results. We discuss our asset and operation divestitures in more detail in the *Notes to Consolidated Financial Statements* beginning on page 15.

We record merchant energy revenues and expenses in our financial results in different periods depending upon which portion of our business they affect and based on the associated accounting policies. We discuss our revenue recognition policies in the *Critical Accounting Policies* section and in *Note 1* of our 2008 Annual Report on Form 10-K.

As part of managing our total portfolio risk, we use economic value at risk. We view economic value at risk as the most comprehensive measure of our exposure to changing commodity prices. This metric measures the risk in our total portfolio, encompassing all aspects of our merchant energy business. We also use daily value at risk and stop loss limits and liquidity guidelines to restrict the level of risk in our portfolio.

Our Global Commodities 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 returns.

We discuss the impact of our economic value at risk and value at risk in more detail in the *Mark-to-Market* and *Risk Management* sections.

Results

	Quarter Ended June 30,		**Six Months Ended June 30,**	
	2009	**2008**	**2009**	**2008**
	(In millions)			
Revenues	**$ 3,201.0**	$ 4,280.1	**$ 6,480.5**	$ 8,227.1
Fuel and purchased energy expenses	**(2,321.8)**	(3,229.2)	**(5,016.6)**	(6,528.1)
Operating expenses	**(382.6)**	(546.2)	**(817.2)**	(976.0)
Merger termination and strategic alternatives costs	**(4.0)**		**(46.3)**	
Impairment losses and other costs	**(60.5)**		**(89.1)**	
Workforce reduction costs	**(0.4)**		**(11.2)**	
Depreciation, depletion, and amortization	**(65.0)**	(68.1)	**(128.6)**	(139.2)
Accretion of asset retirement obligations	**(18.2)**	(17.0)	**(36.1)**	(33.6)
Taxes other than income taxes	**(26.7)**	(30.5)	**(56.1)**	(58.2)
Net (loss) gain on divestitures	**(129.6)**	76.5	**(464.1)**	91.5
Income (Loss) from Operations	**$ 192.2**	$ 465.6	**$ (184.8)**	$ 583.5
Net Income (Loss)	**$ 20.9**	$ 280.0	**$ (181.8)**	$ 352.7
Net Income (Loss) attributable to common stock	**$ 4.1**	$ 279.7	**$ (199.1)**	$ 351.9

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

International commodities operation and gas trading operation[2]	**$**	**(123.8)**	$		**$**	**(308.0)**	$	
Impairment losses and other costs		**(62.2)**				**(73.4)**		
Impairment of nuclear decommissioning trust assets		**(6.1)**		(2.4)		**(29.8)**		(6.3)
Merger termination and strategic alternatives costs		**(4.0)**				**(46.3)**		
Non-qualifying hedges				(34.7)				(69.3)
Workforce reduction costs		**(1.1)**				**(5.3)**		
Credit facility amendment fees		**(5.2)**				**(8.9)**		
Total Other Items	**$**	**(202.4)**	$	(37.1)	**$**	**(471.7)**	$	(75.6)

Above amounts include intercompany transactions eliminated in our Consolidated Financial Statements. The Information by Operating Segment section within the Notes to Consolidated Financial Statements on page 19 provides a reconciliation of operating results by segment to our Consolidated Financial Statements.

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

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

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Revenues and Fuel and Purchased Energy Expenses

Our merchant energy business manages the revenues we realize from the sale of energy and energy-related products to our customers and our costs of procuring fuel and energy. The difference between revenues and fuel and purchased energy expenses, including all direct expenses, represents 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 primarily to reduce risk and/or improve our liquidity. 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 discuss our merchant energy revenues, fuel and purchased energy expenses, and gross margin below.

Revenues

Our merchant energy revenues decreased $1,079.1 million and $1,746.6 million during the quarter and six months ended June 30, 2009, respectively, compared to the same periods in 2008 primarily due to the following:

	Quarter Ended June 30,	Six Months Ended June 30,
	2009 vs. 2008	
	(In millions)	
Decrease in Global Commodities mark-to-market revenues due to significantly lower trading volumes and unfavorable changes in power and gas prices	$ (465)	$ (440)
Decrease in volume of business primarily related to our international coal and freight operation, which we have divested	(99)	(509)
Increase in contract prices and volume related to our domestic coal operation	85	172
Realization of lower prices and volume of business at our gas trading operation, which we have divested, and absence of revenue due to the sales of certain of our upstream gas properties in 2008	(122)	(213)
Realization of lower volumes on wholesale and retail load at our Global Commodities and Customer Supply operations, partially offset by higher contract prices	(496)	(763)
All other	18	6
Total decrease in merchant revenues	$(1,079)	$ (1,747)

Fuel and Purchased Energy Expenses

Our merchant energy fuel and purchased energy expenses decreased $907.4 million and $1,511.5 million during the quarter and six months ended June 30, 2009, respectively, compared to the same periods in 2008 primarily due to the following:

	Quarter Ended June 30,	**Six Months Ended June 30,**
	2009 vs. 2008	
	(In millions)	
(Decrease) increase in Global Commodities mark-to-market expenses related to international coal purchase contracts due to changes in prices and divestiture of operations	$ (61)	$ 108
Decrease in volume of business primarily related to our international coal and freight operation, which we have divested	(106)	(439)
Increase in contract prices and volume related to our domestic coal operation	40	120
Realization of lower volumes at our gas trading operations, which we have divested	(67)	(143)
Realization of lower contract prices and volumes on wholesale and retail power purchases at our Global Commodities and Customer Supply operations	(726)	(1,194)
All other	13	36
Total decrease in merchant energy fuel and purchased energy expenses	$ (907)	$ (1,512)

Gross Margin

We analyze our merchant energy gross margin in the following categories:

Generation our operation that owns, operates, and maintains fossil, nuclear, and renewable generating facilities and holds interests in qualifying facilities, and power projects in the United States and Canada. We present the gross margin results of this operation based on a 100% hedged assumption for the portfolio, related to both output from the facilities and the fuel used to generate electricity. The assumption is based on executing hedges at current market prices with the Global Commodities operation at the end of each fiscal year in order to ensure that the Generation operation is fully hedged. Therefore, all commodity price risk is managed by and presented in the results of our Global Commodities operation as discussed below. Changes in gross margin of our Generation operation during the period are due to changes in

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the level of output from the generating assets, and changes in gross margin between years are a result of changes in prices and expected output.

Customer Supply our load-serving operation that provides energy products and services to wholesale and retail electric and natural gas customers, including distribution utilities, cooperatives, aggregators, and commercial, industrial and governmental customers. We present the gross margin results of this operation based on the gross margin value of new customer supply arrangements at the time of execution assuming an estimated level of customer usage and the impact of any changes in the underlying usage of the customers based on actual energy deliveries. Changes in estimated customer usage result from attrition (customers changing suppliers) or variable load risk (changes in actual usage when compared to expected usage). All commodity price risk is presented in and managed by our Global Commodities operation as discussed below.

Global Commodities our marketing, risk management, and trading operation that manages contractually owned physical assets, including generation facilities, natural gas properties, provides risk management services, and trades energy and energy-related commodities. This operation provides the wholesale risk management function for our Generation and Customer Supply operations, as well as our structured products and energy investments portfolios, and includes our merchant energy business' actual hedged positions with third parties. Therefore, changes in gross margin for this operation result mostly from changes in commodity prices and positions across the various commodities and regions in which we transact.

We provide a summary of our gross margin for these three components of our merchant energy business as follows:

	Quarter Ended June 30,				Six Months Ended June 30,			
	2009		**2008**		**2009**		**2008**	
	(Dollar amounts in millions)							
		% of Total		**% of Total**		**% of Total**		**% of Total**
Gross Margin:								
Generation	**$ 486**	**55%**	$ 375	36%	**$ 1,018**	**69%**	$ 873	51%
Customer Supply	**256**	**29**	296	28	**425**	**29**	395	23
Global Commodities	**137**	**16**	380	36	**21**	**2**	431	26
Total	**$ 879**	**100%**	$ 1,051	100%	**$ 1,464**	**100%**	$ 1,699	100%

Generation

The $111 million increase in Generation gross margin during the quarter ended June 30, 2009 compared to the same period of 2008 is primarily due to the following:

$58 million increase from higher energy prices on hedged gross margin with Global Commodities for the output of our generating assets in the PJM and New York regions based on prices established at the end of 2008 (see Global Commodities discussion below for impact of prices during 2009), and

$53 million due to the timing and duration of planned and unplanned outages at our nuclear and fossil generating plants.

The $145 million increase in generation gross margin during the six months ended June 30, 2009 compared to the same period of 2008 is primarily due to the following:

$93 million increase from higher energy prices on hedged gross margin with Global Commodities for the output of our generating assets in the PJM and New York regions based on prices established at the end of 2008 (see Global Commodities discussion below for impact of prices during 2009), and

$78 million due to the timing and duration of planned and unplanned outages at our nuclear and fossil generating plants.

These increases were partially offset by $26 million of lower gross margin primarily related to our investment in power projects.

<u>Customer Supply</u>

The $40 million decrease in Customer Supply gross margin during the quarter ended June 30, 2009 compared to the same period of 2008 is primarily due to the following:

- $68 million related to lower realization of contracts executed in prior periods and lower new business originated and realized during the quarter primarily in our wholesale and retail power supply operations, and

- $21 million of higher costs due to lower customer retention and variable load risk associated with

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wholesale and retail power primarily due to variances from normal weather and lower demand during the quarter ended June 30, 2009.

These decreases were partially offset by the following:

$25 million of higher gross margin related to the consolidation of a retail power supply variable interest entity (VIE) for which we became the primary beneficiary in December 2008, and

$24 million of higher mark-to-market results primarily in our retail gas operation. We discuss these results in more detail in the *Mark-to-Market* section beginning on page 51.

The $30 million increase in customer supply gross margin during the six months ended June 30, 2009 compared to the same period of 2008 is primarily due to:

$43 million of higher gross margin mostly related to the consolidation of a retail power supply VIE for which we became the primary beneficiary in December 2008, and

$9 million of lower costs due to higher customer retention and from managing variable load risk associated with wholesale and retail power primarily due to less extreme weather during the quarter ended March 31, 2009.

These increases were partially offset by $22 million of lower mark-to-market results primarily in our retail gas operation. We discuss these results in more detail in the *Mark-to-Market* section beginning on page 51.

During the quarter and six months ended June 30, 2009, the higher margin related to the consolidated retail power supply VIE is fully attributable to noncontrolling interests.

Global Commodities

We present Global Commodities results in the following categories:

Portfolio Management and Trading our centralized risk management service related to energy price risk associated with our generation fleet, wholesale and retail customer supply business, and our structured products portfolio.

Structured Products customized risk management products in the power, gas, coal and freight markets (e.g., generation tolls, gas transport and storage, and global coal logistics). As of June 30, 2009, we have reduced our participation in the coal, freight and gas trading markets through the execution of our strategic initiatives.

Energy Investments investments in energy assets that primarily include natural gas properties and a joint interest in an entity that owns dry bulk cargo vessels. We have entered into an agreement to sell our investment in an entity that owns the dry bulk cargo vessels. We expect that sale to close in the third quarter of 2009. We discuss this investment in more detail on page 14 of the *Notes to Consolidated Financial Statements*.

The $243 million decrease in gross margin from our Global Commodities activities during the quarter ended June 30, 2009 compared to the same period of 2008 is primarily due to:

$318 million of lower gross margin related to our portfolio management and trading operation. These changes are discussed further below.

$35 million of lower gross margin from our energy investment operation primarily related to lower new business and backlog realized within the quarter.

These decreases were partially offset by an increase in our structured products portfolio of $110 million primarily as a result of a termination of in-the-money energy sales contract and derivative contracts during the quarter ended June 30, 2009 for a cash payment. Substantially all of the $110 million in gross margin otherwise would have been recognized during 2009. This transaction improved our liquidity in addition to reducing our performance and credit risk exposures.

The decrease in our portfolio management and trading operation gross margin of $318 million is primarily due to the following:

- $403 million of lower earnings related to our portfolio of contracts subject to mark-to-market accounting. We discuss these results in more detail in the *Mark-to-Market* section beginning on page 51,

- $21 million of lower gross margin due to the absence of activity at our international coal and freight operations which were divested as of March 2009.

These decreases were partially offset by the following:

- $68 million related to gains recognized on hedges due to ineffectiveness and certain cash-flow hedges that no longer qualified for hedge accounting during the quarter,

- $21 million related to the absence of a write-down of our emission allowance inventory recorded in the quarter ended June 30, 2008 to reflect market price decreases, and

- $17 million of higher gross margin related to portfolio management of positions arising from hedges with our Generation and Customer Supply activities due to the favorable impact of changes in prices of power, natural gas, and coal on those positions.

The $410 million decrease in gross margin from our Global Commodities operation for the six months ended

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June 30, 2009 compared to the same period in 2008 is primarily due to:

- $296 million of lower gross margin related to our portfolio management and trading operation. These changes are discussed further below.
- $69 million of lower gross margin from our energy investments operation primarily related to lower new business and backlog realized within the quarter.
- $45 million of lower gross margin in our structured products portfolio primarily as a result of fewer terminations of in-the-money energy purchase and sales contracts during the six months ended June 30, 2009 for a cash payment. In 2009, we also transferred associated hedges related to a terminated sales contract.

The decrease in our portfolio management and trading operation gross margin of $296 million is primarily due to the following:

- $561 million of lower earnings related to our portfolio of contracts subject to mark-to-market accounting. We discuss these results in more detail in the *Mark-to-Market* section below,
- $166 million loss reclassified from accumulated other comprehensive loss to earnings in connection with the closing of our international commodities operation as a result of hedged transactions that were probable of not occurring by the end of the specified contract period.

These decreases were partially offset by the following:

- $156 million of higher gross margin related to portfolio management of positions arising from hedges with our Generation and Customer Supply activities due to the favorable impact of changes in prices of power, natural gas, and coal on those positions,
- $154 million related to gains recognized on hedges due to ineffectiveness and certain cash-flow hedges that no longer qualified for hedge accounting during the quarter,
- $59 million of higher gross margin primarily due to the absence of our international coal and freight operations, which were divested in March 2009,
- $55 million related to the absence of a loss due to the bankruptcy of one of our domestic coal suppliers. During the first quarter of 2008, as a result of a default by the supplier, we terminated our derivative contracts with the supplier, reclassified the related asset to accounts receivable and fully reserved the amount, and
- $7 million related to a lower write-down of our emission allowance inventory for the six months ended June 30, 2009 as compared to the same period in 2008 as a result of market prices declining below our cost.

Mark-to-Market

Mark-to-market results include net gains and losses from origination, risk management, and trading activities for which we use the mark-to-market method of accounting. We discuss these activities and the mark-to-market method of accounting in more detail in the *Critical Accounting Policies* section of our 2008 Annual Report on Form 10-K.

The nature of our operations and the use of mark-to-market accounting for certain activities create fluctuations in mark-to-market earnings. We cannot predict these fluctuations, but the impact on our earnings could be material. We discuss our market risk in more detail in the *Risk Management* section beginning on page 70. The primary factors that cause fluctuations in our mark-to-market results are:

- changes in the level and volatility of forward commodity prices and interest rates,
- counterparty creditworthiness,

the number and size of our open derivative positions, and

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

As discussed earlier, we are continuing to assess the ongoing capital requirements of the merchant energy business and are continuing to implement various alternative strategies. Additionally, we have focused our activities on reducing capital requirements, reducing long-term economic risk, and reducing short-term liquidity requirements. These actions may impact the future results of the merchant energy business, particularly the size of and potential for changes in fair value of activities subject to mark-to-market accounting.

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

Origination gains arise primarily from contracts that our Global Commodities operation structures to meet the risk management needs of our customers or relate to our trading activities. Transactions that result in origination gains may be unique and provide the potential for individually significant revenues and gains from a single transaction.

Risk management and trading mark-to-market represents both realized and unrealized gains and losses from changes in the value of our portfolio, including the effects of changes in valuation adjustments. In addition to our fundamental risk management and trading activities, we also use non-trading derivative contracts subject to mark-to-market accounting to manage our exposure to

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changes in market prices, while in general the underlying physical transactions related to these activities are accounted for on an accrual basis. We discuss the changes in mark-to-market results below. We show the relationship between our mark-to-market results and the change in our net mark-to-market energy asset later in this section.

Mark-to-market results were as follows:

	Quarter Ended June 30,				Six Months Ended June 30,			
	2009		2008		2009		2008	
	(In millions)							
Unrealized mark-to-market results								
Origination gains	**$**		$	8.8	**$**		$	68.5
Risk management and trading mark-to-market								
Unrealized changes in fair value		**(22.5)**		347.1		**(217.0)**		297.5
Changes in valuation techniques								
Reclassification of settled contracts to realized		**158.8**		(179.5)		**(157.9)**		(146.9)
Total risk management and trading mark-to-market		**136.3**		167.6		**(374.9)**		150.6
Total unrealized mark-to-market*		**136.3**		176.4		**(374.9)**		219.1
Realized mark-to-market		**(158.8)**		179.5		**157.9**		146.9
Total mark-to-market results**	**$**	**(22.5)**	$	355.9	**$**	**(217.0)**	$	366.0

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

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

Total mark-to-market results decreased $378.4 million during the quarter ended June 30, 2009 compared to the same period of 2008 primarily due to unrealized changes in fair value. This change was primarily due to lower unrealized risk management and trading losses of $369.6 million and a decrease in origination gains of $8.8 million. We discuss origination gains below.

The decrease in risk management and trading results of $369.6 million is primarily due to:

$337 million of lower gains on open positions in our power and transmission risk management activities primarily in the Northeast region due to a less favorable price environment and strong results in the second quarter of 2008 that did not recur in the same period of 2009,

$115 million of increased losses on open positions primarily related to unfavorable prices and correlation failures for derivatives not qualifying for hedge accounting in our domestic coal portfolio, and

$56 million of lower gains in our international coal and freight operation primarily as a result of its divestiture near the end of March 2009.

These decreases were partially offset by the following:

$110 million of lower losses in our wholesale and retail natural gas risk management and trading operation primarily as a result of its divestiture in the beginning of April 2009, and

$28 million of lower losses related to our emissions trading activities primarily as a result of a more favorable price environment.

Total mark-to-market results decreased $583.0 million during the six months ended June 30, 2009 compared to the same period of 2008 primarily due to unrealized changes in fair value. The period-to-period variance in unrealized changes in fair value was primarily due to lower unrealized risk management and trading losses of $514.5 million and the decrease in origination gains of $68.5 million. We discuss origination gains below.

The decrease in risk management and trading results of $514.5 million is primarily due to:

$351 million of lower gains on open positions in our power and transmission risk management activities primarily in the PJM, Northeast, and New York regions due to a less favorable price environment and strong results in the second quarter of 2008 that did not recur in the same period of 2009,

$216 million of increased losses on open positions primarily related to unfavorable prices in our domestic coal portfolio, and

$48 million of lower gains in our international coal and freight operation primarily as a result of its divestiture near the end of March 2009.

These decreases were partially offset by $100 million of lower losses in our wholesale and retail natural gas risk management and trading operation primarily as a result of the divestiture of our gas trading operation in the beginning of April 2009.

We did not record any origination gains during the six months ended June 30, 2009. During the six months ended June 30, 2008, our Global Commodities operation amended certain nonderivative contracts to mitigate counterparty performance risk under the existing contracts. As a result of these amendments, the revised contracts became derivatives subject to mark-to-market accounting. The change in accounting for these contracts from

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nonderivative to derivative resulted in substantially all of the origination gains for 2008 presented in the table above.

Derivative Assets and Liabilities

Derivative assets and liabilities consisted of the following:

	June 30, 2009	December 31, 2008
	(In millions)	
Current Assets	**$ 1,036.4**	$ 1,465.0
Noncurrent Assets	**747.2**	851.8
Total Assets	**1,783.6**	2,316.8
Current Liabilities	**1,272.8**	1,241.8
Noncurrent Liabilities	**937.5**	1,115.0
Total Liabilities	**2,210.3**	2,356.8
Net Derivative Position	**$ (426.7)**	$ (40.0)
Composition of net derivative position:		
Hedges	**$ (1,167.9)**	$ (1,837.6)
Mark-to-market	**801.2**	1,485.9
Net cash collateral included in derivative balances	**(60.0)**	311.7
Net Derivative Position	**$ (426.7)**	$ (40.0)

As discussed in the *Critical Accounting Policies* section of our 2008 Annual Report on Form 10-K, our "Derivative assets and liabilities" include contracts accounted for as hedges and those accounted for on a mark-to-market basis. These amounts are presented in our Consolidated Balance Sheets after the impact of legally binding master netting agreements. Due to the impacts of commodity prices, the number of open positions, master netting arrangements, and offsetting risk positions on the presentation of our derivative assets and liabilities in our Consolidated Balance Sheets, we believe an evaluation of the net position is the most relevant measure, and is discussed in more detail below.

The decrease in our net derivative liability subject to hedge accounting since December 31, 2008 of $669.7 million was due primarily to $1,212 million of realization of out-of-the-money cash-flow hedges, partially offset by $542 million of increases on our out-of-the-money cash-flow hedge positions primarily related to decreases in power, natural gas, and coal prices during the six months ended June 30, 2009.

The following are the primary sources of the change in the net mark-to-market derivative asset during the quarter and six months ended June 30, 2009:

	Quarter Ended June 30, 2009	Six Months Ended June 30, 2009
	(in millions)	
Fair value beginning of period	$ 1,036.4	$ 1,485.9
Changes in fair value recorded in earnings		

Origination gains	$		$	
Unrealized changes in fair value	(22.5)		(217.0)	
Changes in valuation techniques				
Reclassification of settled contracts to realized	158.8		(157.9)	
Total changes in fair value		136.3		(374.9)
Changes in value of exchange-listed futures and options		(76.4)		328.1
Net change in premiums on options		15.6		9.0
Contracts acquired		(116.2)		(35.7)
Dedesignated contracts and other changes in fair value		(194.5)		(611.2)
Fair value at end of period		$ 801.2		$ 801.2

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

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

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

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

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

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

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

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

Contracts acquired represents the initial fair value of acquired derivative contracts recorded in "Derivative assets and liabilities" in our Consolidated Balance Sheets. Substantially all of this activity for the quarter and six months ended June 30, 2009 related to the divestiture of our international commodities operation, Houston-based gas trading operation, and certain other trading operations in order to transfer risk and reward to the buyers. We discuss this divestiture in more detail beginning on page 14 of the *Notes to Consolidated Financial Statements*.

Dedesignated contracts and other changes in fair value represent transfers of derivative contracts from cash flow hedges to mark-to-market treatment, transfers of derivative contracts from mark-to-market treatment to cash flow hedges, and those derivative contracts that did not meet the qualifications of cash flow hedge accounting. In the quarter and six months ended June 30, 2009, substantially all of the activity related to dedesignations in connection with the strategic objective of restructuring and reducing the risk of our portfolio.

The settlement terms of the portion of our net derivative asset subject to mark-to-market accounting and sources of fair value based on the fair value hierarchy are as follows as of June 30, 2009:

	Settlement Term							
	2009	2010	2011	2012	2013	2014	Thereafter	Fair Value
	(In millions)							
Level 1	$ (9.3)	$	$	$	$	$	$	$ (9.3)
Level 2	162.5	46.9	260.8	134.5	(16.4)	(2.1)	1.4	587.6
Level 3	298.4	253.5	(132.7)	(182.8)	(12.2)	2.8	(4.1)	222.9
Total net derivative asset subject to mark-to-market accounting	$451.6	$300.4	$ 128.1	$ (48.3)	$(28.6)	$ 0.7	$ (2.7)	$ 801.2

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

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

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

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

Operating Expenses

Our merchant energy business operating expenses decreased $163.6 million for the quarter ended June 30, 2009 as compared to the same period of 2008 primarily due to lower performance-based labor and benefit costs of $130.2 million and lower non-labor operating expenses of $33.4 million.

Our merchant energy business operating expenses decreased $158.8 million for the six months ended June 30, 2009 as compared to the same period of 2008 primarily due to lower performance-based labor and benefit costs of $123.3 million and lower non-labor operating expenses of $35.5 million.

Merger Termination and Strategic Alternatives Costs

We discuss costs related to the mergers and strategic alternatives in more detail on page 11 in *Notes to Consolidated Financial Statements*.

Impairment losses and Other Costs

Our impairment losses and other costs are discussed in more detail beginning on page 13 in *Notes to Consolidated Financial Statements*.

Workforce Reduction Costs

Our merchant energy business recognized expenses associated with our workforce reduction efforts as discussed in more detail beginning on page 14 in *Notes to Consolidated Financial Statements*.

Amortization of Credit Facility Amendment Fees

Our merchant energy business incurred costs related to the amortization of credit facility amendment fees in connection with the EDF transaction. These costs are classified as interest expense in our Consolidated Statements of Income (Loss).

Depreciation, Depletion and Amortization Expense

Our merchant energy business incurred lower depreciation, depletion and amortization expenses of $10.6 million during the six months ended June 30, 2009 compared to the same period of 2008 primarily due to the absence of depletion expenses as a result of divestitures made in 2008 in our upstream gas operations.

Regulated Electric Business

Our regulated electric business is discussed in detail in *Item 1. Business Electric Business* section of our 2008 Annual Report on Form 10-K.

Results

	Quarter Ended June 30,		Six Months Ended June 30,	
	2009	**2008**	**2009**	**2008**
	(In millions)			
Revenues	**$ 655.7**	$ 448.7	**$ 1,462.5**	$ 1,158.1
Electricity purchased for	**(402.5)**	(404.3)	**(927.7)**	(859.6)

resale expenses				
Operations and maintenance expenses	**(103.9)**	(98.2)	**(195.0)**	(192.9)
Depreciation and amortization	**(55.0)**	(47.8)	**(110.5)**	(98.6)
Taxes other than income taxes	**(36.0)**	(31.6)	**(73.3)**	(67.8)
Income (Loss) from Operations	**$ 58.3**	$ (133.2)	**$ 156.0**	$ (60.8)
Net Income (Loss)	**$ 22.1**	$ (101.7)	**$ 67.5**	$ (65.5)
Net Income (Loss) attributable to common stock	**$ 19.5**	$ (104.2)	**$ 62.4**	$ (70.5)
Other Items Included in Operations (after-tax):				
Accrual of Maryland settlement credit	**$**	$ (125.3)	**$**	$ (125.3)
Effective tax rate impact of Maryland settlement agreement		2.0		5.0
Total Other Items	**$**	$ (123.3)	**$**	$ (120.3)

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 19 provides a reconciliation of operating results by segment to our Consolidated Financial Statements.

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Net income attributable to common stock from the regulated electric business for the quarter ended June 30, 2009 exceeded the net loss attributable to common stock from the regulated electric business for the quarter ended June 30, 2008 by $123.7 million, mostly due to the absence in 2009 of the impact of the accrual of the Maryland settlement credit of $125.3 million after-tax in 2008. This was partially offset by the absence in 2009 of the favorable impact of reduced earnings from the Maryland settlement agreement on our effective tax rate of $2.0 million in 2008.

Net income attributable to common stock from the regulated electric business for the six months ended June 30, 2009 exceeded the net loss attributable to common stock from the regulated electric business for the six months ended June 30, 2008 by $132.9 million, mostly due to increased revenues less electricity purchased for resale expenses of $142.7 million after-tax due to the absence in 2009 of the impact of the accrual of the Maryland settlement credit of $125.3 million after-tax in 2008. The increase was partially offset by increased depreciation and amortization of $7.2 million after-tax and the absence in 2009 of the favorable impact of reduced earnings from the Maryland settlement agreement on our effective tax rate of $5.0 million in 2008.

Electric Revenues

The changes in electric revenues in 2009 compared to 2008 were caused by:

	Quarter Ended June 30, 2009 vs. 2008	Six Months Ended June 30, 2009 vs. 2008
	(In millions)	
Distribution volumes	$ (3.4)	$ 0.7
Nuclear decommissioning charges	4.3	9.1
Smart energy savers program surcharges	5.8	11.1
Maryland settlement credit	188.2	188.2
Revenue decoupling	8.3	10.4
Standard offer service	(0.2)	69.3
Rate stabilization recovery	0.4	2.3
Financing credits	0.1	1.1
Senate Bill 1 credits	2.2	7.4
Total change in electric revenues from electric system sales	205.7	299.6
Other	1.3	4.8
Total change in electric revenues	$ 207.0	$ 304.4

Distribution Volumes

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

The percentage changes in our electric distribution volumes, by type of customer, in 2009 compared to 2008 were:

	Quarter Ended June 30, 2009 vs. 2008	**Six Months Ended June 30, 2009 vs. 2008**
Residential	(4.8)%	(3.1)%
Commercial	1.3	3.2
Industrial	(5.7)	(8.0)

During the quarter ended June 30, 2009 compared to the same period of 2008, we distributed less electricity to residential customers mostly due to milder weather and decreased usage per customer, partially offset by an increased number of customers. We distributed more electricity to commercial customers due to increased usage per customer and an increased number of customers. We distributed less electricity to industrial customers primarily

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due to decreased usage per customer and a decreased number of customers.

During the six months ended June 30, 2009 compared to the same period of 2008, we distributed less electricity to residential customers mostly due to decreased usage per customer, partially offset by colder weather and an increased number of customers. We distributed more electricity to commercial customers due to increased usage per customer and an increased number of customers. We distributed less electricity to industrial customers primarily due to decreased usage per customer and a decreased number of customers.

Nuclear Decommissioning Charges

Effective January 1, 2009, BGE and Calvert Cliffs Nuclear Power Plant Inc. (Calvert Cliffs) mutually agreed to terminate the decommissioning funds collection agent agreement, which was effective from July 1, 2000 to December 31, 2008. As a result, BGE ceased transferring funds to provide for the decommissioning of Calvert Cliffs Unit 1 and Unit 2. Calvert Cliffs retains the obligation to provide adequate assurances of funding pursuant to Nuclear Regulatory Commission requirements. Under the 2008 Maryland settlement agreement, BGE will continue to provide certain credits to residential customers and assess certain charges to all customers relating to decommissioning.

Smart Energy Savers Program Surcharges℠

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

Maryland Settlement Credit

In 2008, BGE entered into a settlement agreement with the State of Maryland and other parties, which provided residential electric customers a credit totaling $170 per customer. The total settlement of $188.2 million was accrued in the second quarter of 2008 and was paid in the third quarter of 2008.

Revenue Decoupling

Beginning in 2008, the Maryland PSC allows us to record a monthly adjustment to our electric distribution revenues from residential and small commercial customers to eliminate the effect of abnormal weather and usage patterns per customer on our electric distribution volumes. Beginning in February 2009, the Maryland PSC allows us to record a monthly adjustment to our electric distribution revenues from the majority of our large commercial and industrial customers to eliminate the effect of abnormal weather and usage patterns per customer on our electric distribution volumes. This means our monthly electric distribution revenues for these customers are based on weather and usage that is considered "normal" for the month. Therefore, while these revenues are affected by customer growth, they will not be affected by actual weather or usage conditions.

Standard Offer Service

BGE provides standard offer service for customers that do not select an alternative supplier. We discuss the provisions of Senate Bill 1 related to residential electric rates in the *Item 7. Management's Discussion and Analysis Business Environment Regulation Maryland Senate Bills 1 and 400* section of our 2008 Annual Report on Form 10-K.

Standard offer service revenues increased during the six months ended June 30, 2009 compared to the same period of 2008, mostly due to an increase in the standard offer service rates, partially offset by lower standard offer service volumes.

Rate Stabilization Recovery

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

Financing Credits

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

Senate Bill 1 Credits

As a result of Senate Bill 1, beginning January 1, 2007, we were required to provide to residential electric customers a credit equal to the amount collected from all BGE electric customers for the decommissioning of Calvert Cliffs and to suspend collection of the residential return component of the administrative charge collected through residential standard offer service rates through May 31, 2007. Under an order issued by the Maryland PSC in May 2007, as of June 1, 2007, we were required to reinstate collection of the residential return component of the administration charge in rates and to provide all residential electric customers a credit for the residential return component of

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the administrative charge. Under the 2008 Maryland settlement agreement, BGE was allowed to resume collection of the residential return portion of the administrative charge from June 1, 2008 through May 31, 2010 without having to rebate it to residential customers.

The increase in revenues during the quarter and six months ended June 30, 2009 compared to the same period in 2008 is primarily due to the absence of the credit for the residential return component of the administrative charge which was suspended under the Maryland settlement agreement, partially offset by lower distribution volumes.

Electricity Purchased for Resale Expenses

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

	Quarter Ended June 30,		Six Months Ended June 30,	
	2009	**2008**	**2009**	**2008**
		(In millions)		
Actual costs	**$ 392.0**	$ 393.1	**$ 901.4**	$ 834.3
Recovery under rate stabilization plans	**10.5**	11.2	**26.3**	25.3
Electricity purchased for resale expenses	**$ 402.5**	$ 404.3	**$ 927.7**	$ 859.6

Actual Costs

BGE's actual costs for electricity purchased for resale increased $67.1 million during the six months ended June 30, 2009 compared to the same period of 2008, primarily due to higher contract prices to purchase electricity for our customers, partially offset by lower volumes.

Recovery Under Rate Stabilization Plan

In late June 2007, we began recovering previously deferred amounts from customers. During the quarter and six months ended June 30, 2009, $9.7 million and $24.3 million, respectively, of the amount recovered secures the payment of principal and interest and other ongoing costs associated with rate stabilization bonds issued by a subsidiary of BGE in June 2007.

Electric Operations and Maintenance Expenses

Regulated electric operations and maintenance expenses increased $5.7 million in the quarter ended June 30, 2009 compared to the same period in 2008, primarily due to increased uncollectible accounts receivable expense of $13.0 million, partially offset by the absence of $5.3 million of incremental distribution service restoration expenses associated with 2008 storms and $2.9 million of lower labor and benefit costs.

Regulated electric operations and maintenance expenses increased $2.1 million in the six months ended June 30, 2009 compared to the same period in 2008, primarily due to increased uncollectible accounts receivable expense of $16.7 million, partially offset by the absence of $6.9 million in incremental distribution service restoration expenses associated with 2008 storms and $7.2 million of lower labor and benefit costs.

We discuss the Allowance for Uncollectible Accounts Receivable in more detail beginning on page 61.

Electric Depreciation and Amortization

Regulated electric depreciation and amortization expense increased $7.2 million during the quarter ended June 30, 2009, compared to the same period in 2008, primarily due to $9.8 million in increased amortization expense associated with the Smart Energy Savers Program^{SM} and additional property placed in service in 2009, partially offset by $3.8 million in lower depreciation expense as a result of revised depreciation rates which were implemented on June 1, 2008 for regulatory and financial reporting purposes as part of the Maryland settlement agreement.

Regulated electric depreciation and amortization expense increased $11.9 million during the six months ended June 30, 2009, compared to the same period in 2008, primarily due to $17.7 million in increased amortization expense associated with the smart energy savers programs and additional property placed in service in 2009, partially offset by $9.5 million in lower depreciation expense as a result of revised depreciation rates which were implemented on June 1, 2008 for regulatory and financial reporting purposes as part of the Maryland settlement agreement.

The Maryland settlement agreement is discussed in more detail in *Note 2 to Consolidated Financial Statements* of our 2008 Annual Report on Form 10-K.

Taxes Other Than Income Taxes

Taxes other than income taxes increased $4.4 million and $5.5 million during the quarter and six months ended June 30, 2009, respectively, compared to the same periods in 2008, primarily due to the absence of the impact of the Maryland settlement agreement on franchise taxes.

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Regulated Gas Business

Our regulated gas business is discussed in detail in *Item 1. Business Gas Business* section of our 2008 Annual Report on Form 10-K.

Results

	Quarter Ended June 30,		Six Months Ended June 30,	
	2009	**2008**	**2009**	**2008**
		(In millions)		
Revenues	**$ 111.7**	$ 188.1	**$ 498.6**	$ 584.5
Gas purchased for resale expenses	**(51.6)**	(127.7)	**(309.7)**	(397.7)
Operations and maintenance expenses	**(45.0)**	(38.6)	**(80.9)**	(77.5)
Depreciation and amortization	**(10.7)**	(11.2)	**(22.1)**	(23.1)
Taxes other than income taxes	**(8.5)**	(8.4)	**(18.9)**	(18.8)
(Loss) Income from operations	**$ (4.1)**	$ 2.2	**$ 67.0**	$ 67.4
Net (Loss) Income	**$ (6.2)**	$ (2.3)	**$ 33.4**	$ 37.9
Net (Loss) Income attributable to common stock	**$ (6.9)**	$ (3.1)	**$ 31.9**	$ 36.3
Other Items Included in Operations (after-tax):				
Effective tax rate impact of Maryland settlement agreement	**$**	$ 0.1	**$**	$ 3.7

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 19 provides a reconciliation of operating results by segment to our Consolidated Financial Statements.

Net loss attributable to common stock from the regulated gas business increased $3.8 million during the quarter ended June 30, 2009, compared to the same period of 2008, primarily due to increased operations and maintenance expenses of $3.9 million after-tax, which consisted primarily of $3.0 million after-tax of increased uncollectible accounts receivable expense.

Net income attributable to common stock from the regulated gas business decreased $4.4 million during the six months ended June 30, 2009, compared to the same period of 2008, primarily due to the absence in 2009 of the impact of reduced earnings from the Maryland settlement agreement on our effective tax rate of $3.7 million.

Gas Revenues

The changes in gas revenues in 2009 compared to 2008 were caused by:

	Quarter Ended	Six Months Ended

	June 30, 2009 vs. 2008	June 30, 2009 vs. 2008
	(In millions)	
Distribution volumes	$ (0.9)	$ 5.4
Conservation surcharge	0.2	0.7
Gas revenue decoupling	0.9	(5.1)
Gas cost adjustments	(46.8)	(31.9)
Total change in gas revenues from gas system sales	(46.6)	(30.9)
Off-system sales	(29.3)	(53.8)
Other	(0.5)	(1.2)
Total change in gas revenues	$ (76.4)	$ (85.9)

Distribution Volumes

The percentage changes in our distribution volumes, by type of customer, in 2009 compared to 2008 were:

	Quarter Ended June 30, 2009 vs. 2008	Six Months Ended June 30, 2009 vs. 2008
Residential	2.2%	6.7%
Commercial	(22.3)	(5.8)
Industrial	13.2	6.8

During the quarter ended June 30, 2009 compared to the same period in 2008, we distributed more gas to residential customers, due to increased usage per customer and an increased number of customers, partially offset by milder weather. We distributed less gas to commercial customers compared to the same period of 2008, mostly due to decreased usage per customer, partially offset by an increased number of customers. We distributed more gas to industrial customers mostly due to increased usage by customers, partially offset by a decreased number of customers.

During the six months ended June 30, 2009 compared to the same period in 2008, we distributed more gas to residential customers due to colder weather and an increased number of customers, partially offset by decreased usage per customer. We distributed less gas to commercial customers due to decreased usage per customer, partially

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offset by an increased number of customers and colder weather. We distributed more gas to industrial customers mostly due to increased usage per customer, partially offset by a decreased number of customers.

Conservation Surcharge

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

Gas Revenue Decoupling

The Maryland PSC allows us to record a monthly adjustment to our gas distribution revenues to eliminate the effect of abnormal weather and usage patterns per customer on our gas distribution volumes. This means our monthly gas distribution revenues are based on weather and usage that is considered "normal" for the month. Therefore, while these revenues are affected by customer growth, they will not be affected by actual weather or usage conditions.

Gas Cost Adjustments

We charge our gas customers for the natural gas they purchase from us using gas cost adjustment clauses set by the Maryland PSC as described in *Note 1* of our 2008 Annual Report on Form 10-K. However, under the market-based rates mechanism approved by the Maryland PSC, our actual cost of gas is compared to a market index (a measure of the market price of gas in a given period). The difference between our actual cost and the market index is shared equally between shareholders and customers.

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

Gas cost adjustment revenues decreased $46.8 million and $31.9 million during the quarter and six months ended June 30, 2009, respectively, compared to the same period of 2008, because we sold less gas at lower prices.

Off-System Gas Sales

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

Revenues from off-system gas sales decreased during the quarter and six months ended June 30, 2009 compared to the same period of 2008 because we sold less gas at lower prices.

Gas Purchased For Resale Expenses

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

Gas costs decreased $76.1 million during the quarter ended June 30, 2009 compared to the same period of 2008 because we purchased less gas at lower prices.

Gas costs decreased $88.0 million during the six months ended June 30, 2009 compared to the same period of 2008 because we purchased gas at lower prices, partially offset by higher volumes.

Gas Operations and Maintenance Expenses

Regulated gas operation and maintenance expenses increased $6.4 million in the quarter ended June 30, 2009 compared to the same period in 2008, primarily due to increased uncollectible accounts receivable expense of $5.0 million.

Regulated gas operation and maintenance expenses increased $3.4 million during the six months ended June 30, 2009 compared to the same period in 2008, primarily due to increased uncollectible accounts receivable expense of $6.5 million, partially offset by $2.9 million in lower labor and benefit costs.

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Other Nonregulated Businesses

Results

	Quarter Ended June 30,		Six Months Ended June 30,	
	2009	**2008**	**2009**	**2008**
	(In millions)			
Revenues	**$ 51.6**	$ 66.1	**$ 108.9**	$ 125.3
Operating expense	**(41.3)**	(53.6)	**(83.6)**	(99.0)
Impairment losses and other costs	**(6.7)**		**(6.7)**	
Depreciation and amortization	**(18.2)**	(14.8)	**(36.3)**	(29.3)
Taxes other than income taxes	**(1.2)**	(0.6)	**(2.0)**	(1.1)
(Loss) Income from Operations	**$ (15.8)**	$ (2.9)	**$ (19.7)**	$ (4.1)
Net (Loss) Income	**$ (8.5)**	$ (1.0)	**$ (10.5)**	$ (0.7)
Net (Loss) Income attributable to common stock	**$ (8.6)**	$ (0.9)	**$ (10.6)**	$ (0.5)
Other Items Included in Operations (after-tax):				
Impairment losses and other costs	**$ (3.2)**	$	**$ (3.2)**	$

Above amounts include intercompany transactions eliminated in our Consolidated Financial Statements. The Information by Operating Segment section within the Notes to Consolidated Financial Statements on page 19 provides a reconciliation of operating results by segment to our Consolidated Financial Statements.

Net loss attributable to common stock increased $7.7 million during quarter ended June 30, 2009 and $10.1 million during the six months ended June 30, 2009 compared to the same periods of 2008 primarily due to increased losses from UniStar Nuclear Energy, LLC of $3.4 million and $5.3 million, respectively, increased impairment losses and other costs due to a write-off of an uncollectible advance to an affiliate of $3.2 million after-tax and depreciation and amortization expense as a result of increased property additions during 2008.

Consolidated Nonoperating Income and Expenses

Other Income (Expense)

In the six months ended June 30, 2009, we had other expenses of $15.4 million and, in the six months ended June 30, 2008, we had other income of $58.0 million. The $73.4 million decrease in 2009 compared to 2008 is mostly due to an increase in other-than-temporary impairment charges related to our nuclear decommissioning trust fund assets of $49.9 million.

Fixed Charges

Our fixed charges increased during the quarter and six months ended June 30, 2009 compared to the same periods of 2008 mostly due to a higher level of interest expense associated with new debt issuances, primarily the Series A and Series B Preferred Stock issuances, in 2008 and higher amortization of debt issuance and credit facility costs.

Fixed charges at BGE increased during the quarter and six months ended June 30, 2009 compared to the same periods of 2008 mostly due to a higher level of interest expense associated with new debt issuances in 2008 and higher amortization of debt issuance and credit facility costs.

Income Taxes

Income tax expense decreased $322.4 million during the six months ended June 30, 2009 compared to the same period of 2008 mostly due to a loss before income taxes in 2009 compared to income before income taxes in 2008. Additionally, a higher effective tax rate in 2009 decreased income tax expense because it produced a higher income tax benefit when applied to the loss before income taxes.

BGE's income tax expense for the quarter and six months ended June 30, 2009 exceeded the income tax benefit for the quarter and six months ended June 30, 2008 by $62.1 million and $82.2 million, respectively, mostly due to higher pre-tax income. In addition, for the quarter and six months ended June 30, 2008, BGE had a lower effective tax rate. BGE projected a reduction in its 2008 taxable income as a result of the impact of certain provisions of the 2008 Maryland settlement agreement, which increased the relative impact of the favorable permanent tax adjustments on its effective tax rate.

Allowance for Uncollectible Accounts Receivable

Our allowance for uncollectible accounts receivable increased $19.6 million from $240.6 million at December 31, 2008 to $260.2 million at June 30, 2009, primarily related to our regulated electric and gas businesses, whose allowance for uncollectible accounts receivable increased $17.9 million from December 31, 2008. We discuss the earnings impact to regulated electric and gas businesses on pages 58 and 60.

The increase in allowance for uncollectible accounts receivable from our regulated electric and gas businesses is primarily driven by a Maryland PSC ruling in the second quarter of 2009, which delayed BGE's ability to terminate service to customers with arrearages and offered those

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customers the option to enter into extended payment plans. In addition, the economic downturn continues to cause a decreased ability of customers to pay their utility bills.

If the current economic recession continues on a prolonged basis and the Maryland PSC continues to require BGE to offer extended payment plans, our and BGE's bad debt expense could materially increase in the future despite our efforts to mitigate those risks. We discuss our credit risk in more detail in the *Risk Management* section of our 2008 Annual Report on Form 10-K.

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Financial Condition

Cash Flows

The following table summarizes our cash flows for 2009 and 2008, excluding the impact of changes in intercompany balances.

	2009 Segment Cash Flows			Consolidated Cash Flows	
	Six Months Ended June 30, 2009			Six Months Ended June 30,	
	Merchant	Regulated	Holding Company and Other	2009	2008
			(In millions)		
Operating Activities					
Net (loss) income	$ (181.8)	$ 100.9	$ (10.5)	$ (91.4)	$ 324.4
Non-cash merger termination and strategic alternatives costs	37.2			37.2	
Derivative contracts classified as financing activities under SFAS No. 149	785.3			785.3	0.5
Other non-cash adjustments to net (loss) income	679.5	212.9	56.2	948.6	369.8
Changes in working capital:					
Derivative assets and liabilities, excluding collateral	177.5	(0.1)	7.8	185.2	(700.6)
Net collateral and margin	1,093.3	1.6		1,094.9	525.9
Other changes	116.9	138.5	(37.9)	217.5	58.6
Defined benefit obligations[1]				(263.9)	(44.8)
Other	(40.8)	(20.1)	111.9	51.0	6.2
Net cash provided by operating activities	2,667.1	433.7	127.5	2,964.4	540.0
Investing Activities					
Investments in property, plant and equipment	(635.5)	(166.5)	(7.1)	(809.1)	(869.5)
Asset and business acquisitions, net of cash acquired					(312.4)

Contributions to nuclear decommissioning trust funds	(18.7)			(18.7)	(18.7)
Proceeds from sale of investments and other assets	49.7		31.2	80.9	
Proceeds from sales of property, plant and equipment					217.0
Contract and portfolio acquisitions	(2,153.7)			(2,153.7)	
Decrease (increase) in restricted funds[2]		0.6	1,003.8	1,004.4	(196.9)
Other	(1.7)		(0.1)	(1.8)	12.9
Net cash (used in) provided by investing activities	(2,759.9)	(165.9)	1,027.8	(1,898.0)	(1,167.6)
Cash flows from operating activities less cash flows from investing activities	$ (92.8)	$ 267.8	$ 1,155.3	1,066.4	(627.6)
Financing Activities[1]					
Net (repayment) issuance of debt				(1,587.1)	938.6
Debt issuance costs				(62.8)	(15.6)
Proceeds from issuance of common stock				13.6	8.3
Common stock dividends paid				(133.7)	(165.0)
BGE preference stock dividends paid				(6.6)	(6.6)
Proceeds from contract and portfolio acquisitions				2,243.1	
Derivative contracts classified as financing activities under SFAS No. 149				(785.3)	(0.5)
Other				11.8	3.2
Net cash (used in) provided by financing activities				(307.0)	762.4
Net increase in cash and cash equivalents				$ 759.4	$ 134.8

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

2 The decrease in restricted funds at our Holding Company and Other is primarily related to $1.0 billion of restricted cash related to the issuance of Series B Preferred Stock to EDF in December 2008. These funds were held at the holding company and were restricted for payment of the 14% Senior Notes held by MidAmerican. The 14% Senior Notes were repaid in full in January 2009.

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Cash Flows from Operating Activities

Cash provided by operating activities was $2,964.4 million in 2009 compared to $540.0 million in 2008. This $2,424.4 million increase in cash flows was primarily due to $1,613.7 million of net favorable changes in working capital and a net increase of $784.8 million as a result of a reclassification of proceeds from derivative contracts as financing activities under SFAS No. 149. We discuss the impact on cash flows from financing activities below.

The net favorable changes in working capital of $1,613.7 million included $885.8 million related to net derivative assets and liabilities. Changes in derivative assets and liabilities are driven by fluctuations in commodity prices and the realization of contracts at settlement within our merchant energy business. There was also $569.0 million more in net collateral margin returned in 2009 as compared to 2008.

We continue to improve our collateral position in 2009. Total net cash collateral posted in 2009 decreased compared to the balance as of December 31, 2008 as follows:

	(In millions)
Net collateral and margin posted, December 31, 2008	$ (1,445.6)
Return of collateral held associated with nonderivative contracts	(5.4)
Net return of collateral posted associated with nonderivative contracts	320.9
Return of initial and variation margin posted on exchange-traded transactions recorded in accounts receivable	407.7
Return of fair value net cash collateral posted (netted against derivative assets / liabilities)*	371.7
Change in net collateral and margin posted	1,094.9
Net collateral and margin posted, June 30, 2009	$ (350.7)

** We discuss our netting of fair value collateral with our derivative assets / liabilities in more detail in Note 13 to Consolidated Financial Statements of our 2008 Annual Report on Form 10-K.*

The $1,094.9 million decrease in net collateral and margin posted during 2009 primarily reflects the following:

- fewer contracts as a result of reducing the risk in our portfolio,
- collateral returned/reduced as part of the divestiture of a majority of our international commodities operation and gas trading operation as well as the execution of a gas supply agreement with the buyer of the gas trading operation, and
- the termination of in-the-money contracts.

These decreases were offset by changes in commodity prices and the level of our open positions.

We discuss all forms of collateral in terms of their impact on our net available liquidity in the *Available Sources of Funding* section.

Cash Flows from Investing Activities

Cash used in investing activities was $1,898.0 million in 2009 compared to $1,167.6 million in 2008. The $730.4 million increase in cash used in 2009 compared to 2008 was primarily due to $2,153.7 million for contract and portfolio acquisitions. As a result of the structure of the divestitures of a majority of our international commodities, Houston-based gas trading and other trading operations, we are required to present in-the-money contracts on a gross basis separate from out-of-the-money contracts executed simultaneously. We discuss our divestitures in more detail beginning on page 15 of the *Notes to Consolidated Financial Statements*. There was no such activity in 2008.

This increase was partially offset by:

- a $1,201.3 million decrease in restricted funds, primarily due to the release of funds for the repayment of the $1 billion of 14% Senior Notes to MidAmerican in January 2009, and

- the absence of cash used for acquisitions. $312.4 million was used in the six months ended June 30, 2008 for the acquisition of the Hillabee Energy Center, a partially completed 774 MW gas-fired combined cycle power generation facility in Alabama, the West Valley Power Plant, a 200MW gas-fired peaking plant, and a uranium market participant.

Cash Flows from Financing Activities

Cash used in financing activities was $307.0 million in 2009 compared to cash provided of $762.4 million in 2008. The increase in cash used for financing activities of $1,069.4 million was primarily due to:

- $1,534.7 million net increase in cash used to repay short-term borrowings and long-term debt primarily due to the repayment of the $1 billion 14% Senior Notes to MidAmerican in January 2009,

- $991.0 million net decrease in cash received from the issuance of long-term debt, and

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$784.8 million in cash outflows related to derivative contracts classified as financing activity under SFAS No. 149. These contracts relate to transactions associated with the divestiture of our international commodities operation, Houston-based gas trading operation and certain other trading operations. During the six months ended June 30, 2009, we executed transactions at prices that differed from market prices. As a result, for cash flows associated with the out-of-the money derivative transactions executed, we recorded the ongoing cash flows related to these contracts as financing cash flows. We discuss our divestitures in more detail beginning on page 16 of the *Notes to Consolidated Financial Statements.*

This increase in cash used for financing activities was partially offset by $2,243.1 million for contract and portfolio acquisitions. As a result of the structure of the divestitures of a majority of our international commodities, Houston-based gas trading and other trading operations, we are required to present out-of-the-money contracts on a gross basis separate from in-the-money contracts executed simultaneously. We discuss our divestitures in more detail beginning on page 15 of the *Notes to Consolidated Financial Statements.* There was no such activity in 2008.

Security Ratings

We discuss our security ratings in our 2008 Annual Report on Form 10-K.

On July 31, 2009, Fitch Ratings downgraded Constellation Energy's senior unsecured debt rating from BBB to BBB- and BGE's senior unsecured debt rating from A- to BBB+. Fitch Ratings also updated both companies' ratings outlook from Watch Evolving to Stable.

Available Sources of Funding

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

The primary drivers of our use of liquidity have been our capital expenditure requirements and collateral requirements associated with hedging our generating assets and hedging our Customer Supply business in both power and gas. As part of our strategic initiatives, we have modified the structure of certain transactions and terminated others in order to reduce these collateral requirements. Significant changes in the prices of commodities, depending on hedging strategies we have employed, could require us to post additional letters of credit, and thereby reduce the overall amount available under our credit facilities or to post additional cash, and thereby reduce our available cash balance.

Constellation Energy

At June 30, 2009, we had approximately $5.6 billion in committed credit facilities available as shown below. We have also included in the table below the pro forma effect on our credit facilities of closing the EDF transactions:

Facility Expiration	Facility Size	Facility Size Upon Completion of the EDF Transactions
	(In billions)	
July 2012	$ 3.85	$ 2.32
November 2009[1]	1.23	
September 2013	0.35	
December 2009	0.15	
Total	$ 5.58	$ 2.32

1 Size of facility may be reduced by proceeds received from certain securities offerings or asset sales.

Collectively, these facilities currently support the issuance of letters of credit and/or cash borrowings up to approximately $5.6 billion as of June 30, 2009. At June 30, 2009, we had approximately $2.8 billion in letters of credit issued, and we had no commercial paper outstanding.

In connection with the Investment Agreement with EDF, EDF has provided us with up to $2 billion pre-tax, or approximately $1.4 billion after-tax, of additional liquidity pursuant to a put arrangement that will allow us to require EDF to purchase certain non-nuclear generation assets. The amount of after-tax proceeds will be impacted by the assets actually sold and the related tax impacts at that time.

During April 2009, we received regulatory approvals and consents for the majority of the assets covered by the put arrangement. As of July 31, 2009, we have approximately $1.1 billion after-tax of liquidity available under the put arrangement. We expect to receive regulatory approval for an additional asset in the first quarter of 2010, which will increase the net after-tax liquidity from the put arrangement to approximately $1.4 billion. The put arrangement will expire at the earlier of December 31, 2010 or the termination of the Investment Agreement by EDF in the event of a breach of contract by us.

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Certain credit facilities of Constellation Energy contain a provision requiring Constellation Energy to maintain a ratio of debt to capitalization equal to or less than 65%. At June 30, 2009, the debt to capitalization ratios as defined in the credit agreements were no greater than 51%.

Our $1.23 billion credit facility requires us to maintain consolidated earnings before interest, taxes, depreciation, and amortization to consolidated interest expense ratio of at least 2.75 when our Standard and Poors (S&P) senior unsecured debt rating is BBB- or lower and our Moody's senior unsecured debt rating is Baa3 or lower. Compliance with the covenant is not required as of July 31, 2009 as S&P's senior unsecured debt rating is above BBB-.

The terms of the Series B Preferred Stock allow us to issue debt without the consent of the holders of the majority of the Series B Preferred Stock only if, after issuance of such debt, we maintain a ratio of debt to capitalization equal to or less than 65%.

Under our $3.85 billion and $1.23 billion credit facilities, we will be required to grant a lien on certain generating facilities and pledge our ownership interests in our nuclear business to the lenders upon the earlier of (i) the closing of the Investment Agreement with EDF or (ii) the date on which both the Investment Agreement is terminated and our S&P or FitchRatings senior unsecured debt credit rating is below BBB- or our Moody's senior unsecured debt credit rating is below Baa3.

BGE

BGE currently maintains a $400.0 million five-year revolving credit facility expiring in 2011. BGE can use the facility to issue letters of credit or to issue short-term debt through the issuance of commercial paper or through direct borrowing against the facility. At June 30, 2009, BGE had $0.5 million outstanding on its $400 million credit facility to secure funds in advance of maturing commercial paper and other obligations.

At June 30, 2009, BGE had $339.9 million in commercial paper outstanding.

The credit agreement of BGE contains a provision requiring BGE to maintain a ratio of debt to capitalization equal to or less than 65%. At June 30, 2009, the debt to capitalization ratio for BGE as defined in this credit agreement was 52%.

Decreases in Constellation Energy's or BGE's credit ratings would not trigger an early payment on any of our, or BGE's, credit facilities.

Net Available Liquidity

The following tables provide a summary of our net available liquidity at December 31, 2008 and June 30, 2009:

	As of December 31, 2008		
	Constellation Energy	BGE	Total Consolidated
	(In billions)		
Credit facilities	$ 6.2	$ 0.4	$ 6.6
Less: Letters of credit issued	(3.6)		(3.6)
Less: Cash drawn on credit facilities	(0.5)	(0.4)	(0.9)
Undrawn facilities	2.1		2.1
Less: Commercial paper outstanding			

Net available facilities		2.1				2.1
Add: Cash		0.2				0.2
Net available liquidity	$	2.3	$		$	2.3

	As of June 30, 2009					
	Constellation Energy		BGE		Total Consolidated	
	(In billions)					
Credit facilities	$	5.6	$	0.4	$	6.0
Less: Letters of credit issued		(2.8)				(2.8)
Less: Cash drawn on credit facilities						
Undrawn facilities		2.8		0.4		3.2
Less: Commercial paper outstanding				(0.3)		(0.3)
Net available facilities		2.8		0.1		2.9
Add: Cash		1.0				1.0
Add: EDF put arrangement		1.1				1.1
Net available liquidity	$	4.9	$	0.1	$	5.0

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Net available liquidity increased from December 31, 2008 through June 30, 2009 by $2.7 billion as follows:

		(In billions)
Decrease in cash drawn on facilities	$	0.9
Decrease in letters of credit issued		0.8
Increase in cash		0.8
EDF put arrangement		1.1
Decrease in credit facilities		(0.6)
Increase in commercial paper issued		(0.3)
Increase in net available liquidity	$	2.7

Through our efforts to reduce risk, we have significantly improved our liquidity. Specifically, we executed on our planned divestitures, significantly reduced the activities of our Global Commodities operation, and restructured and terminated existing transactions and amended certain agreements, all of which have led to lower collateral requirements. Through June 30, 2009 we received substantially all of the $1 billion of total net collateral expected to be returned as a result of the successful execution of our divestitures. The change in credit facilities and EDF put arrangement was due to the receipt of required regulatory approvals on the majority of assets covered by the EDF put arrangement, which resulted in the termination of the EDF interim backstop liquidity facility. Finally, cash flows from operating activities funded the repayment of all outstanding cash draws on our credit facilities, and BGE was able to issue $339.9 million of commercial paper, demonstrating an ability to access the capital market in a more traditional manner.

Our liquidity needs vary as commodity prices change. We regularly evaluate the effects of changing price levels on our liquidity needs by estimating the impacts of volatile power, gas, and coal prices on our price sensitive sources and uses of liquidity. For example, energy contracts settling in the current year may impact our cash flows and changing price levels may impact our collateral requirements. Additionally, we consider the impact of other sources and uses of liquidity, including planned business divestitures, anticipated new business, capital expenditures, operating expenses and credit charges.

We believe that the actions that we have taken and our current net available liquidity will be sufficient to support the ongoing liquidity requirements over the next 12 months. Our liquidity projections include assumptions for commodity price changes, which are subject to significant volatility, and we are exposed to certain operational risks that could have a significant impact on our liquidity. We discuss significant items that could negatively impact our liquidity in the *Risk Factors* section of our 2008 Annual Report on Form 10-K.

Collateral

Constellation Energy's collateral requirements arise from its merchant energy business' need to participate in certain organized markets, such as Independent System Operators (ISOs) or financial exchanges, as well as from our margining on over-the-counter (OTC) contracts.

To support wholesale and retail power Customer Supply obligations, as well as some trading activities, Constellation Energy posts collateral to ISOs. Forward hedging of our Generation and Customer Supply obligations, as well as our Global Commodities trading activities, creates the need to transact with exchanges such as New York Mercantile Exchange and Intercontinental Exchange. We post initial margin based on exchange rules, as well as variation margin related to the change in value of the net open position with the exchange. Constellation Energy's initial margin requirements increased during the third quarter of 2008 as a result of changes in exchange rules and decreased during the fourth quarter of 2008 as a result of portfolio risk reduction and downsizing activities.

During the six months ended June 30, 2009, our initial margin requirements continued to decrease. In March 2009 and April 2009, we closed out our exchange positions related to our international commodities operation and Houston-based gas trading operation, respectively, which reduced our margin posted with each exchange with which we transact. Daily variation margin postings to each exchange depend on price moves in the underlying power, gas and coal exchange traded forward and option contracts.

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

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

In our Customer Supply operation, we generally do not receive collateral under contractual obligations to supply power or gas to our customers but our Global Commodities operation hedges these transactions through purchases of power and gas that generally require us to post collateral. By entering into a gas supply agreement with the buyer of our gas trading operation, we have reduced our collateral requirements to support our retail gas operation. We discuss this gas supply agreement in more detail on page 17 of the *Notes to Consolidated Financial Statements*.

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

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contracts, but our generating plants are not a source of collateral.

Customers of our merchant energy business rely on the creditworthiness of Constellation Energy. In this regard, we have certain agreements that contain provisions that would require us to post additional collateral upon a credit rating downgrade in the senior unsecured debt of Constellation Energy. Based on contractual provisions at June 30, 2009, we estimate that if Constellation Energy's senior unsecured debt were downgraded to one level below the investment grade threshold we would have the following additional collateral obligations:

Credit Ratings Downgraded to*	**Level Below Current Rating**	**Additional Obligations****
		(In billions)
Below investment grade	1	$ 1.5

** If there are split ratings among the independent credit-rating agencies, the lowest credit rating is used to determine our incremental collateral obligations.*
*** Includes $0.3 billion related to derivative contracts as discussed in Notes to Consolidated Financial Statements beginning on page 35.*

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

Capital Resources

Our estimated annual cash requirement amounts for the years 2009 and 2010 are shown in the table below.

We will continue to have cash requirements for:

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

Capital requirements for 2009 and 2010 include estimates of spending for existing and anticipated projects. We continuously review and modify those estimates. Actual requirements may vary from the estimates included in the table below because of a number of factors including:

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

business decisions to invest in capital projects.

Our estimates are also subject to additional factors. Please see the *Forward Looking Statements* section on page 75 and *Risk Factors* section in our 2008 Annual Report on Form 10-K. We discuss the potential impact of environmental legislation and regulation in more detail in *Business Environment* section on page 45 and *Item 1. Business Environmental Matters* section of our 2008 Annual Report on Form 10-K.

Calendar Year Estimates	**2009**	**2010**
	(In billions)	
Nonregulated Capital Requirements:		
Merchant energy		
Generation plants[1]	$ 0.4	$ 0.2
Environmental controls	0.3	
Portfolio acquisitions/investments	0.1	0.1
Technology/other	0.1	
Nuclear Fuel[1]	0.2	
Total merchant energy capital requirements	1.1	0.3
Other nonregulated capital requirements	0.1	
Total nonregulated capital requirements	1.2	0.3
Regulated Capital Requirements:		
Regulated electric	0.4	0.7
Regulated gas	0.1	0.1
Total regulated capital requirements	0.5	0.8
Total Capital Requirements	$ 1.7	$ 1.1

1 Assumes the Investment Agreement with EDF closes in the fall of 2009 and we deconsolidate our nuclear generation and operation business. As a result, we are reflecting nine months of nuclear plant related and nuclear fuel capital requirements for 2009 and none for 2010.

Capital Requirements

Merchant Energy Business

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

improvements to generating plants,

nuclear fuel costs,

costs of complying with the EPA, Maryland, and Pennsylvania environmental regulations and legislation, and

enhancements to our information technology infrastructure.

Cost for Decommissioning Nuclear Facilities

Every two years, the U. S. Nuclear Regulatory Commission (NRC) requires us to demonstrate reasonable assurance that funds will be available to decommission our nuclear generating facilities after these facilities cease operation. In response to our March 2009 biennial report, the NRC notified us that they had identified a potential "shortfall" in

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the decommissioning fund balance for certain of our nuclear reactors. This condition was a result of declining market performance during the last two quarters of 2008 for the investments held by our decommissioning trusts.

In July 2009, we filed with the NRC a plan that we expect will enable us to demonstrate by December 2009 reasonable assurance for adequate decommissioning funding in accordance with NRC regulations. Our plan proposes the use of a safe storage approach which allows funds to grow during the extended safe storage period following license termination but prior to decommissioning. In the event the NRC requires additional funding assurance beyond consideration of the safe storage approach, we will provide parental guarantees which would be subject to review and updating as necessary, but which are expected to be less than $70 million in the aggregate as of December 2009. We discuss the costs for decommissioning our nuclear generating facilities in more detail in the *Business Overview* section of our 2008 Annual Report on Form 10-K.

Regulated Electric and Gas

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

In July 2009, BGE filed with the Maryland PSC a proposal for a comprehensive and advanced smart grid initiative. The proposal includes the planned installation of 2 million residential and commercial smart meters. We expect the total cost of the program to be approximately $480 million, although potential stimulus funding from the United States Department of Energy could reduce the cost by as much as $200 million. If approved, this proposal would have a material impact on future regulated electric and gas construction expenditures.

Funding for Capital Requirements

We discuss our funding for capital requirements in our 2008 Annual Report on Form 10-K.

Contractual Payment Obligations and Committed Amounts

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

We detail our contractual payment obligations at June 30, 2009 in the following table:

	Payments				
	2009	2010-2011	2012-2013	There-after	Total
			(In millions)		
Contractual Payment Obligations					
Long-term debt:[1]					
Nonregulated					
Principal	$1,500.5	$ 0.4	$ 721.8	$ 2,625.0	$ 4,847.7
Interest	151.0	314.9	264.3	3,016.6	3,746.8
Total	1,651.5	315.3	986.1	5,641.6	8,594.5
BGE					
Principal	38.4	138.2	639.1	1,422.8	2,238.5
Interest	66.7	258.1	231.3	1,336.6	1,892.7
Total	105.1	396.3	870.4	2,759.4	4,131.2
BGE preference stock				190.0	190.0

Operating leases[2]					
Operating leases, gross	133.8	431.6	382.1	569.1	1,516.6
Sublease rentals	(39.9)	(133.6)	(77.5)	(139.1)	(390.1)
Operating leases, net	93.9	298.0	304.6	430.0	1,126.5
Purchase obligations:[3]					
Purchased capacity and energy[4]	295.8	285.0	188.5	229.8	999.1
Fuel and transportation	528.3	1,143.9	580.5	1,368.1	3,620.8
Other	152.8	122.0	50.8	27.9	353.5
Other noncurrent liabilities:					
FIN 48 tax liability		123.1	2.9	9.8	135.8
Pension benefits[5]	49.2	360.5	292.9	(63.4)	639.2
Postretirement and postemployment benefits[6]	22.5	83.0	95.9	278.4	479.8
Total contractual payment obligations	$ 2,899.1	$ 3,127.1	$ 3,372.6	$ 10,871.6	$ 20,270.4

1 Amounts in long-term debt reflect the original maturity date and include $697.7 million of principal for the Zero Coupon Senior Notes, assuming the notes are not redeemed prior to June 19, 2023 and the original issue discount accrues until redemption. Investors may require us to repay $483.8 million early through remarketing and put features. Interest on variable rate debt is included based on the forward curve for interest rates.

2 Our operating lease commitments include future payment obligations under certain power purchase agreements as discussed further in Note 11 of our 2008 Annual Report on Form 10-K.

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

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

5 Amounts related to pension benefits reflect our current 5-year forecast of contributions for our qualified pension plans and participant payments for our nonqualified pension plans. Refer to Note 7 of our 2008 Annual Report on Form 10-K for more detail on our pension plans.

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

Off-Balance Sheet Arrangements

We discuss our off-balance sheet arrangements in our 2008 Annual Report on Form 10-K.

At June 30, 2009, Constellation Energy had a total face amount of $14.1 billion in guarantees outstanding, of which $12.7 billion related to our merchant energy business. These amounts do not represent incremental consolidated Constellation Energy obligations; rather, they primarily represent parental guarantees of certain subsidiary obligations to third parties in order to allow our subsidiaries the flexibility needed to conduct business with counterparties without having to post other forms of collateral. Our estimated net exposure for obligations under commercial transactions covered by these guarantees was approximately $2.5 billion at June 30, 2009, which represents the total amount the parent company could be required to fund based on June 30, 2009 market prices. For those guarantees related to our derivative liabilities, the fair value of the obligation is recorded in our Consolidated Balance Sheets. We believe it is unlikely that we would be required to perform or incur any losses associated with guarantees of our subsidiaries' obligations.

We discuss our other guarantees in the *Notes to Consolidated Financial Statements* beginning on page 23.

Risk Management

Market Risk

Economic Value at Risk (EVaR)

EVaR is a measure that attempts to estimate the sensitivity of our total portfolio economic value to changes in market prices. The EVaR measure includes all positions of our merchant business, including Generation, Customer Supply, and Global Commodities operations. Each business day, the Company undertakes EVaR calculations that include both its trading and its non-trading risks. EVaR for non-trading positions measures the amount of potential change in the fair values of the exposures related to accrual exposures. EVaR is a one-day measure calculated at a 95% confidence level on the portfolio through 2013. At June 30, 2009, our EVaR was approximately $97 million, which represents a 29% decline from its level of $136 million at December 31, 2008.

Due to the inherent limitations of statistical measures such as EVaR and the seasonality of changes in market prices, the EVaR calculation may not reflect the full extent of our commodity price risk exposure. Additionally, because our EVaR methodology uses a linear approximation method, actual changes in the value of options in our portfolio resulting from significant price changes may differ from estimates generated using this methodology. As a result, actual changes in the fair value of derivative assets and liabilities subject to mark-to-market accounting could differ from the calculated EVaR, and such changes could have a material impact on our financial results.

While EVaR reflects the risk of loss under normal market conditions, stress testing captures Constellation Energy's exposure to unlikely but plausible events in abnormal markets. We regularly conduct economic value stress tests for our market activities using multiple scenarios that assume stressed changes in both price level and spreads. Additional scenarios focus on the risks predominant in individual portions of our business segments and include scenarios that focus on loss of generation, customer demand growth or demand destruction, or a shift in the composition of load serving customers.

Along with EVaR, stress testing is important in measuring and controlling risk. Stress testing enhances the understanding of Constellation Energy's risk profile and loss potential, and stress losses are monitored against limits. We also use stress testing in approvals of non-standard transactions and for cross-business risk measurement, as well as an input to economic capital allocation. Stress test results, trends, and explanations are provided each month to Constellation Energy's senior management and to the lines of business to help them better measure and manage risks and to understand event risk-sensitive positions.

Value at Risk (VaR)

Where EVaR is a measure that attempts to estimate the sensitivity of our total portfolio economic value, VaR is a measure that attempts to measure the sensitivity of our mark-to-market energy contracts of our Global Commodities operation to potential changes in market prices. VaR is a statistical model designed to predict risk of loss based on historical market price volatility. We calculate VaR using a historical variance/covariance technique that models option positions using a linear approximation of their value. Additionally, we estimate variances and correlation using historical commodity price changes over the most recent rolling three-month period. Our VaR calculation includes all of our Global Commodities operation derivative assets and liabilities subject to mark-to-market accounting, including contracts for energy commodities and derivatives that result in physical settlement and contracts that require cash settlement. VaR is a statistical risk measurement model subject to limitations similar to those of EVaR.

The VaR calculation does not include market risks associated with activities that are subject to accrual accounting, primarily our generating facilities and our customer supply load-serving activities.

The VaR amounts below represent the potential pre-tax loss in the fair value of our Global Commodities operation derivative assets and liabilities subject to mark-to-market accounting, including both trading and

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non-trading activities, over one and ten-day holding periods.

Total Wholesale VaR	Quarter Ended June 30, 2009
	(In millions)
99% Confidence Level, One-Day Holding Period	
Average	$ 17.6
High	22.9
95% Confidence Level, One-Day Holding Period	
Average	13.4
High	17.4
95% Confidence Level, Ten-Day Holding Period	
Average	42.4
High	55.1

Constellation Energy's proprietary trading activities are greatly reduced from previous years and are largely focused on price discovery. These activities continue to be managed with daily VaR limits, stop loss limits and liquidity guidelines and are immaterial relative to the overall portfolio VaR.

Credit Risk

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

As of June 30, 2009 and December 31, 2008, counterparties in the credit portfolio of our Global Commodities operation had the following public credit ratings:

	June 30, 2009	December 31, 2008
Rating		
Investment Grade[1]	**57%**	52%
Non-Investment Grade	**9**	15
Not Rated	**34**	33

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

Our exposure to "Not Rated" counterparties was $1 billion at June 30, 2009 compared to $1.5 billion at December 31, 2008. This decrease was mostly due to a decrease in our portfolio's credit exposure to natural gas customers, international coal customers, and freight companies that do not have public credit ratings as a result of the divestiture of a majority of our international commodities operation.

Many of our not rated counterparties are considered investment grade equivalent based on our internal credit ratings. We utilize internal credit ratings to evaluate the creditworthiness of our wholesale customers, including those companies that do not have public credit ratings. Based on internal credit ratings, approximately $528.5 million or 52% of the exposure to not rated counterparties was rated investment grade equivalent at June 30, 2009 and approximately $883.7 million or 60% was rated investment grade equivalent at December 31, 2008.

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

	June 30, 2009	December 31, 2008
Investment Grade Equivalent	**77%**	74%
Non-Investment Grade	**23**	26

Our total exposure, net of collateral, to counterparties across our entire wholesale portfolio is $3 billion as of June 30, 2009. The top ten counterparties account for 37% of our total exposure. As shown in the table below, no single counterparty concentration comprises more than 10% of the total exposure of the portfolio.

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

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Our total exposure of $3 billion, net of collateral, includes accrual positions and derivatives. The portion of our wholesale credit risk related to transactions that are recorded in our Consolidated Balance Sheets, net of collateral, totals approximately $1 billion and primarily relates to open energy commodity positions from our Global Commodities operation that are accounted for using mark-to-market accounting, derivatives that qualify for designation as hedges, as well as amounts owed by wholesale counterparties for transactions that settled but have not yet been paid.

The following table highlights the credit quality and exposures related to these activities at June 30, 2009:

Rating	Total Exposure Before Credit Collateral	Credit Collateral	Net Exposure	Number of Counterparties Greater than 10% of Net Exposure	Net Exposure of Counterparties Greater than 10% of Net Exposure
			(In millions)		
Investment grade	$ 1,319	$ 493	$ 826		$
Split rating	18	1	17		
Non-investment grade	117	66	51		
Internally rated investment grade	72		72		
Internally rated non-investment grade	67		67		
Total	$ 1,593	$ 560	$ 1,033		$

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

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

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

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

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

We discuss our exposure to interest rate risk, retail credit risk, foreign currency risk, security price risk and operational risk in the *Risk Management* section of our 2008 Annual Report on Form 10-K.

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Item 3. Quantitative and Qualitative Disclosures About Market Risk

We discuss the following information related to our market risk:

- hedging activities in the *Notes to Consolidated Financial Statements* beginning on page 27,
- activities of our Global Commodities operation in the *Merchant Energy Business* section of *Management's Discussion and Analysis* beginning on page 50,
- evaluation of commodity and credit risk in the *Risk Management* section of *Management's Discussion and Analysis* beginning on page 70, and
- changes to our business environment in the *Business Environment* section of *Management's Discussion and Analysis* on page 44.

Items 4 and 4(T). Controls and Procedures

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

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

Evaluation of Disclosure Controls and Procedures

The principal executive officers and principal financial officers of both Constellation Energy and BGE have evaluated the effectiveness of the disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")) as of the end of the fiscal quarter covered by this quarterly report (the "Evaluation Date"). Based on such evaluation, such officers have concluded that, as of the Evaluation Date, Constellation Energy's and BGE's disclosure controls and procedures are effective.

Changes in Internal Control over Financial Reporting

During the quarter ended June 30, 2009, there has been no change in either Constellation Energy's or BGE's internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) that has materially affected, or is reasonably likely to materially affect, either Constellation Energy's or BGE's internal control over financial reporting.

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PART II. OTHER INFORMATION

Item 1. Legal Proceedings

We discuss our Legal Proceedings in the *Notes to Consolidated Financial Statements* beginning on page 24.

Item 2. Issuer Purchases of Equity Securities

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

Period	Total Number of Shares Purchased[1]	Average Price Paid for Shares	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Dollar Amounts of Shares that May Yet Be Purchased Under the Plans and Programs (at month end)[2]
April 1 April 30, 2009	15,533	$ 20.42		$ 750 million
May 1 May 31, 2009	1,129	23.14		750 million
June 1 June 30, 2009	2,067	26.83		750 million
Total	18,729	$ 21.29		

1 Represents shares surrendered by employees to satisfy tax withholding obligations on vested restricted stock and restricted stock units.
2 In October 2007, our Board of Directors approved a common share repurchase program for up to $1 billion of our outstanding common shares over the 24 months following approval. Pursuant to the terms of our Series B Preferred Stock, we are prohibited from engaging in a common share repurchase in an aggregate amount in excess of $100 million without the approval of the holders of more than 50% of the then outstanding shares of Series B Preferred Stock.

Item 4. Submission of Matters to Vote of Security Holders

On May 29, 2009, we held our annual meeting of shareholders. At that meeting, the following matters were voted upon:

1. Directors nominated by Constellation Energy were elected to serve for a term to expire in 2010 and until their successors are duly elected and qualified as follows:

	COMMON SHARES CAST:		
	For	Against	Abstain
Yves C. de Balmann	165,975,225	5,556,613	2,559,713
Ann C. Berzin	165,915,138	5,659,901	2,516,513
James T. Brady	164,989,362	8,148,322	953,874
James R. Curtiss	167,249,182	5,844,567	997,804
Freeman A. Hrabowski III	153,038,551	20,120,649	932,357
Nancy Lampton	166,360,505	6,724,875	1,006,172
Robert J. Lawless	152,871,815	20,224,820	994,921
Lynn M. Martin	155,696,864	17,372,666	1,022,024
Mayo A. Shattuck III	148,029,915	25,207,202	854,445
John L. Skolds	166,282,660	5,303,808	2,505,089
Michael D. Sullivan	147,786,173	25,308,509	996,873

2. The ratification of PricewaterhouseCoopers LLP as independent registered public accounting firm for 2009 was approved. With respect to holders of common stock, the number of affirmative votes cast was 170,190,530, the number of votes cast against was 2,977,483, and the number of abstentions was 923,544.

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Item 5. Other Information

Forward Looking Statements

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

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

the liquidity and competitiveness of wholesale markets for energy commodities,

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

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

the ability to complete our strategic initiatives to improve our liquidity and the impact of such initiatives on our business and financial results,

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

the ability to successfully identify, finance, and complete acquisitions and sales of businesses and assets,

the likelihood and timing of the completion of the pending transaction with EDF Group and related entities (EDF), the terms and conditions of any required regulatory approvals for the pending transaction, potential impact of a termination of the pending transaction and potential diversion of management's time and attention from our ongoing business during this time period,

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

the ability to attract and retain customers in our Customer Supply activities and to adequately forecast their energy usage,

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

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

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

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

the ability of BGE to recover all its costs associated with providing customers service, operational factors affecting commercial operations of our generating facilities (including nuclear facilities) and BGE's transmission and distribution facilities, including catastrophic weather-related damages, unscheduled outages or repairs, unanticipated changes in fuel costs or availability, unavailability of coal or gas transportation or electric transmission services, workforce issues, terrorism, liabilities associated with catastrophic events, and other events beyond our control,

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

changes in accounting principles or practices, and

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

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

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

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Item 6. Exhibits

Exhibit No. 4(a)*	Indenture and Security Agreement dated as of July 9, 2009, between Baltimore Gas and Electric Company and Deutsche Bank Trust Company Americas, as trustee (including form of Baltimore Gas and Electric Company Officer's Certificate and form of Senior Secured Bond) (Designated as Exhibits 4(u) and 4(u)(1) to Post-Effective Amendment No. 1 to the Registration Statement on Form S-3 dated July 9, 2009, File Nos. 333-157637 and 333-157637-01).
Exhibit No. 4(b)*	Baltimore Gas and Electric Company Deed of Easement and Right-of-Way Grant dated as of July 9, 2009 (Designated as Exhibit 4(u)(2) to Post-Effective Amendment No. 1 to the Registration Statement on Form S-3 dated July 9, 2009, File Nos. 333-157637 and 333-157637-01).
Exhibit No. 12(a)	Constellation Energy Group, Inc. Computation of Ratio of Earnings to Fixed Charges.
Exhibit No. 12(b)	Baltimore Gas and Electric Company Computation of Ratio of Earnings to Fixed Charges and Computation of Ratio of Earnings to Combined Fixed Charges and Preferred and Preference Dividend Requirements.
Exhibit No. 31(a)	Certification of Chairman of the Board, President, and Chief Executive Officer of Constellation Energy Group, Inc. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
Exhibit No. 31(b)	Certification of Senior Vice President and Chief Financial Officer of Constellation Energy Group, Inc. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
Exhibit No. 31(c)	Certification of President and Chief Executive Officer of Baltimore Gas and Electric Company pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
Exhibit No. 31(d)	Certification of Senior Vice President and Chief Financial Officer of Baltimore Gas and Electric Company pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
Exhibit No. 32(a)	Certification of Chairman of the Board, President, and Chief Executive Officer of Constellation Energy Group, Inc. pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
Exhibit No. 32(b)	Certification of Senior Vice President and Chief Financial Officer of Constellation Energy Group, Inc. pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
Exhibit No. 32(c)	Certification of President and Chief Executive Officer of Baltimore Gas and Electric Company pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
Exhibit No. 32(d)	Certification of Senior Vice President and Chief Financial Officer of Baltimore Gas and Electric Company pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
Exhibit No. 101.INS	XBRL Instance Document
Exhibit No. 101.SCH	XBRL Taxonomy Extension Schema Document
Exhibit No. 101.PRE	XBRL Taxonomy Presentation Linkbase Document
Exhibit No. 101.LAB	XBRL Taxonomy Label Linkbase Document
Exhibit No. 101.CAL	XBRL Taxonomy Calculation Linkbase Document
Exhibit No. 101.DEF	XBRL Taxonomy Definition Linkbase Document

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* Incorporated by reference

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

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SIGNATURE

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

	CONSTELLATION ENERGY GROUP, INC
	(Registrant)
Date: August 7, 2009	/s/ JONATHAN W. THAYER
	Jonathan W. Thayer, ***Senior Vice President of Constellation Energy Group, Inc. and as Principal Financial Officer***
	BALTIMORE GAS AND ELECTRIC COMPANY
	(Registrant)
Date: August 7, 2009	/s/ KEVIN W. HADLOCK
	Kevin W. Hadlock, ***Senior Vice President of Baltimore Gas and Electric Company and as Principal Financial Officer***