CONSTELLATION ENERGY GROUP INC
Form 10-K
February 27, 2009

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended **DECEMBER 31, 2008**

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

MARYLAND
(States of incorporation)

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

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

SECURITIES REGISTERED PURSUANT TO SECTION 12(B) OF THE ACT:

Title of each class	Name of each exchange on which registered
Constellation Energy Group, Inc. Common Stock Without Par Value	New York Stock Exchange Chicago Stock Exchange
Constellation Energy Group, Inc. Series A Junior Subordinated Debentures 6.20% Trust Preferred Securities ($25 liquidation amount per preferred security) issued by BGE Capital Trust II, fully and unconditionally guaranteed, based on several obligations, by Baltimore Gas and Electric Company	New York Stock Exchange

SECURITIES REGISTERED PURSUANT TO SECTION 12(G) OF THE ACT:

Not Applicable

Indicate by check mark if Constellation Energy Group, Inc. is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ý No o.

Indicate by check mark if Baltimore Gas and Electric Company is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ý No o.

Indicate by check mark if Constellation Energy Group, Inc. is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes o No ý.

Indicate by check mark if Baltimore Gas and Electric Company is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes o No ý.

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrants' knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. o

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

Large accelerated filer ý Accelerated filer o Non-accelerated filer o Smaller reporting company o

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

Large accelerated filer o Accelerated filer o Non-accelerated filer ý Smaller reporting company o

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

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

Aggregate market value of Constellation Energy Group, Inc. Common Stock, without par value, held by non-affiliates as of June 30, 2008 was approximately $14,585,929,431 based upon New York Stock Exchange composite transaction closing price.

CONSTELLATION ENERGY GROUP, INC. COMMON STOCK, WITHOUT PAR VALUE
199,127,544 SHARES OUTSTANDING ON JANUARY 30, 2009.

DOCUMENTS INCORPORATED BY REFERENCE

Part of Form 10-K	Document Incorporated by Reference
III	Certain sections of the Proxy Statement for the 2009 Annual Meeting of Shareholders for Constellation Energy Group, Inc.

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

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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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PART I

Item 1. Business

Overview

Constellation Energy is an energy company that includes a merchant energy business and BGE, a regulated electric and gas public utility in central Maryland. References in this report to "we" and "our" are to Constellation Energy and its subsidiaries, collectively. References in this report to the "regulated business(es)" are to BGE.

Our merchant energy business is primarily a competitive provider of energy-related products and services for a variety of customers. It develops, owns, and operates electric generation facilities located in various regions of the United States. Our merchant energy business focuses on serving the energy and capacity requirements (load-serving) of, and providing other energy products and risk management services for, various customers.

BGE is a regulated electric transmission and distribution utility company and a regulated gas distribution utility company with a service territory that covers the City of Baltimore and all or part of 10 counties in central Maryland. BGE was incorporated in Maryland in 1906.

Our other nonregulated businesses:

- design, construct, and operate renewable energy, heating, cooling, and cogeneration facilities, and provide various energy-related services, including energy consulting, for commercial, industrial, and governmental customers throughout North America,
- provide home improvements, service heating, air conditioning, plumbing, electrical, and indoor air quality systems, and provide natural gas to residential customers in central Maryland, and
- develop new nuclear plants in North America through our joint venture (UniStar Nuclear Energy, LLC) with a subsidiary of EDF Group.

As a capital- and asset-intensive business, Constellation Energy was significantly impacted by events in the financial and credit markets during 2008. This has resulted in substantial ongoing changes to our business.

Over the past few years, our merchant energy business, which includes our trading operations and international commodities operation, grew rapidly. As that business grew, so too did its need for capital, particularly to fund the business' collateral requirements. We had previously met these collateral requirements through the use of cash and lines of credit, and we believed that we could meet any unexpected short-term capital needs by maintaining a significant amount of available liquidity, primarily from our unused credit facilities. Furthermore, by maintaining an investment grade credit rating, we believed we would continue to be able to access the capital markets if additional liquidity needs arose.

The growth of our merchant energy business and its increased need for collateral, coupled with significant volatility in commodity prices in 2008, required us to post substantial amounts of incremental collateral to our counterparties. The asymmetrical nature of the Customer Supply business' collateral posting requirements compounded the magnitude of the problem, negatively impacting our overall liquidity. We discuss the asymmetrical nature of our collateral in more detail in *Item 7. Management's Discussion and Analysis Collateral* section.

To address these liquidity issues, in 2008, we explored a series of strategic initiatives to improve our liquidity and reduce our business risk. In the first half of 2008, we began to pursue the sale or joint venturing of our highly capital-intensive commodities business based on the concern that our balance sheet could not support the significant growth of this business long-term. We embarked on a process and solicited bids from interested parties and although interest levels were high, following the collapse of Bear Stearns and the significant difficulties encountered by other major financial institutions, we determined we would not get reasonable value for our business. In August 2008, we began efforts to sell our upstream gas properties and our international commodities operation, which includes our coal sourcing, freight, power, natural gas, uranium, and emissions marketing activities outside the United States. In November 2008, we announced we had begun efforts to sell our gas trading operation. We have made progress on many of these initiatives as discussed in more detail in the *Divestitures* section.

In September 2008, a rapid and extreme increase in volatility of U.S. and global credit and capital markets caused us to face severe, near-term uncertainty about our ability to maintain sufficient liquidity to continue operating our business. The rating agencies downgraded Constellation Energy's credit ratings because of concerns over our liquidity. The downgrades, in turn, required us to post additional collateral assurance to some of our counterparties, and, since we could not access the capital markets, this further reduced our available liquidity. At that time, we had not made significant progress with our strategic initiatives to generate substantial reductions in our collateral requirements or substantial improvements in our liquidity. As a result, we sought an immediate, substantial investment to ensure our ability to continue operating our business, and in mid-September we ultimately agreed to a transaction with MidAmerican Energy Holdings Company (MidAmerican) that involved an immediate $1 billion preferred equity investment by MidAmerican in us, followed by an all cash sale of our company to MidAmerican for $4.7 billion. In early December 2008, we received an unsolicited offer from EDF Group and related entities

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(EDF) to acquire a membership interest in our nuclear generation and operation business. Our Board of Directors determined the EDF proposal to be in the best interests of our shareholders. Therefore, on December 17, 2008, we and MidAmerican terminated the planned transaction, and we simultaneously entered into a series of transactions with EDF.

The EDF transactions do not involve the sale of Constellation Energy, but rather the sale of a membership interest in our nuclear generation and operation business resulting in the Company continuing to operate on a standalone basis. The transactions that we agreed to with EDF include the following:

- EDF will purchase from Constellation Energy a 49.99% membership interest in our nuclear generation and operation business for $4.5 billion (subject to certain adjustments) at closing and an additional $150 million of cash received in 2008,
- EDF is providing Constellation Energy with up to $2 billion of additional liquidity pursuant to a put arrangement that will allow us to require EDF to purchase certain non-nuclear generation assets,
- EDF invested $1 billion in Constellation Energy by purchasing 10,000 shares of our 8% Series B Preferred Stock (Series B Preferred Stock). These shares will be surrendered to us when EDF purchases its membership interest in our nuclear generation and operation business, and the $1 billion will be credited against the $4.5 billion purchase price,
- EDF provided us with a $600 million interim backstop liquidity facility, and
- Prior to closing, we will transfer to our nuclear generation and operation business transactions with a negative mark-to-market value not to exceed $700 million in the aggregate using a 10% discount rate. This transfer will occur in a manner that is to be determined and to be mutually acceptable to Constellation Energy and EDF.

For additional information related to these transactions with MidAmerican and EDF, see *Note 15 to Consolidated Financial Statements*. For additional information related to the issuance of the Series B Preferred Stock, see *Note 9 to Consolidated Financial Statements*.

Over the next one to two years, we expect to be in a transition period during which we will focus on executing the following objectives that we believe will strengthen the Company:

- continuing to implement strategic initiatives to reduce collateral and liquidity needs of our merchant energy business, including selling certain assets and operations as discussed further in the *Divestitures* section.
- working to close the sale to EDF of 49.99% of our nuclear generation and operation business as expeditiously as possible,
- continuing a disciplined approach to the management of collateral and liquidity, including:
  - pricing new business to reflect the full cost of capital in the current economic environment and possibly requiring deposits from new retail customers that do not meet pre-existing credit conditions,
  - balancing cash generation with earnings growth, and
  - maintaining a liquidity cushion in excess of credit-rating downgrade collateral requirements,
- focusing on Constellation Energy's core strengths of:
  - owning, developing, and operating nuclear and non-nuclear generation assets,
  - providing reliable, regulated utility service to customers,
  - leveraging our expertise in managing physical risks inherent in our Generation and Customer Supply operations, and
  - maintaining strong supply relationships with retail and wholesale customers,

- continuing to reduce the scale of and re-focus the activities of our Global Commodities and Customer Supply operations through the following actions:
  - using the Global Commodities group to support our Generation and Customer Supply operations,
  - placing less reliance on proprietary trading, and
  - investing capital in areas where we are able to generate appropriate risk-adjusted returns,
- maintaining credit metrics consistent with investment grade ratings.

We believe that focusing on the near-term execution of the above objectives will allow us to preserve the flexibility to respond to long-term opportunities. For a further discussion of the above matters and how they have impacted us and our strategy, please refer to *Item 7. Management's Discussion and Analysis*.

Divestitures

In 2009, we made progress on many of the strategic initiatives we identified in 2008 to improve liquidity and reduce our business risk. These initiatives included selling our international commodities operation, which primarily includes our coal sourcing, freight, power, natural gas, uranium, and emissions marketing activities; our gas trading operation; and our upstream gas properties.

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In January 2009, we entered into a definitive agreement to sell a majority of our international commodities operation. In February 2009, we entered into a definitive agreement to sell our Houston-based gas trading operation. Simultaneously, we signed a letter of intent to enter into a related transaction with an affiliate of the buyer under which that company would provide us with the gas supply needed to support our retail gas customer supply business, while reducing our credit requirements. We expect that both of these sales will close by the end of the second quarter of 2009, subject to certain regulatory approvals and other standard closing conditions. Upon closing of these transactions, we expect to recognize an aggregate pre-tax loss of not more than $200 million based on current commodity prices. The actual amount of the loss will be affected by the final consideration exchanged, which is based on the timing of the close, and by changes in commodity prices. The impact on cash is not expected to be material.

Collectively, we expect both divestitures to return to us approximately $1 billion of currently posted collateral. In addition, we expect these divestitures to further reduce our downgrade collateral requirements by approximately $400 million. These reductions are based on current commodity prices, the final terms of the transactions, and the timing of collateral to be returned up to the close of the transactions, and, as a result, are subject to change. We discuss our downgrade collateral requirements in *Item 7. Management's Discussion and Analysis Collateral* section.

While we sold certain of our upstream gas properties in 2008, we continue to evaluate the sale of our remaining upstream gas properties while monitoring market conditions for opportunities to obtain appropriate value for these upstream gas properties. Unlike our international commodities operation and our gas trading operation, there are no material collateral needs associated with the remaining properties, minimizing the need to divest these immediately.

Operating Segments

The percentages of revenues, net income (loss), and assets attributable to our operating segments are shown in the tables below. We present information about our operating segments, including certain other items, in *Note 3 to Consolidated Financial Statements*.

	Unaffiliated Revenues			
	Merchant Energy	Regulated Electric	Regulated Gas	Holding Company and Other Nonregulated
2008	80%	14%	5%	1%
2007	83	12	4	1
2006	83	11	5	1

	Net Income (Loss) (1)			
	Merchant Energy	Regulated Electric	Regulated Gas	Holding Company and Other Nonregulated
2008	(103)%	%	3%	%
2007	83	12	3	2
2006	77	16	5	2

	Total Assets			
	Merchant Energy	Regulated Electric	Regulated Gas	Holding Company and Other Nonregulated
2008 (2)	62%	21%	6%	11%
2007	73	20	6	1
2006	75	17	6	2

(1)
Excludes income from discontinued operations in 2007 and 2006 as discussed in more detail in Item 8. Financial Statements and Supplementary Data.

(2) *The increase in Holding Company and Other Nonregulated assets is primarily related to approximately $1.6 billion of intercompany receivables from the merchant energy business, primarily related to the allocation of merger termination and Series A Preferred Stock conversion costs to these businesses, and $1.0 billion of restricted cash related to the issuance of Series B Preferred Stock to EDF. These funds are held at the holding company and are 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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Merchant Energy Business

Introduction

Our merchant energy business generates and sells power and gas to both regulated and nonregulated wholesale and retail marketers and consumers of energy products, manages all commodity price risk for our nonregulated businesses, enters into structured energy contracts, and trades energy. We conduct these activities across all regions in the United States and internationally.

Our merchant energy business includes:

- a power generation and development operation that owns, operates, and maintains fossil and renewable generating facilities, and holds interests in qualifying facilities, fuel processing facilities and power projects in the United States,
- a nuclear generation operation that owns, operates, and maintains nuclear generating facilities,
- a customer supply operation that primarily provides energy products and services to meet the load-serving obligations of wholesale and retail customers, including distribution utilities, cooperatives, aggregators, and commercial, industrial and governmental customers, and
- a global commodities operation that manages contractually controlled physical assets, including generation facilities, natural gas properties, international coal sourcing and freight operations; provides risk management services and uranium marketing services; and trades energy and energy-related commodities.

In 2008, we began pursuing a number of strategic initiatives that will impact our merchant energy business in 2009 and future years. We discuss these strategic initiatives and how they have impacted our merchant energy business segment and our strategy in *Item 7. Management's Discussion and Analysis*. We also discuss certain asset and operations divestitures in the *Divestitures* section.

During 2008, our merchant energy business:

- supplied approximately 26,600 megawatts (MW) of aggregate peak load to distribution utilities, municipalities, and commercial, industrial, and governmental customers,
- provided approximately 407,000 million British Thermal Units (mmBTUs) of natural gas to commercial, industrial, and governmental customers,
- delivered approximately 25.4 million tons of coal to international and domestic third-party customers and to our own fleet, and
- managed 9,136 MW of generation capacity as of December 31.

We analyze our merchant energy business in terms of Generation, Customer Supply and Global Commodities activities.

- Generation encompasses all of our generating assets.
- Customer Supply encompasses our load-serving operation that provides energy products and services to wholesale and retail electric and natural gas customers.
- Global Commodities encompasses our marketing, risk management, and trading operations, global coal sourcing and logistics services, and upstream and downstream natural gas services.

Generation

We own, operate, and maintain fossil, nuclear, and renewable generating facilities and hold interests in qualifying facilities, and power projects in the United States and Canada totaling 9,136 MW. We also provide operation and maintenance services, including testing and start-up, to owners of electric generating facilities. The output of these plants is managed by our Global Commodities operation and is hedged through a combination of power sales to wholesale and retail market participants. Our merchant energy business meets the load-serving requirements of various contracts using the output from our generating fleet and from purchases in the wholesale market.

We present details about our generating properties in *Item 2. Properties.*

Nuclear

The output of our nuclear facilities over the past three years is presented in the following table:

	Calvert Cliffs		Nine Mile Point		Ginna	
	MWH	Capacity Factor	MWH *	Capacity Factor	MWH	Capacity Factor
	(MWH in millions)					
2008	14.7	96%	12.8	94%	4.7	94%
2007	14.3	94	12.3	90	4.9	98
2006	13.8	90	12.8	93	4.1	93

* *represents our proportionate ownership interest*

We sell a significant portion of the output from our Nine Mile Point Nuclear Station (Nine Mile Point) and our R.E. Ginna Nuclear Plant (Ginna) under unit-specific power purchase agreements. We discuss these arrangements on the next page. Our Global Commodities operation manages the remainder of our generation output.

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In December 2008, we entered into the Investment Agreement with EDF under which EDF will purchase a 49.99% membership interest in our nuclear generation and operation business, which owns our three nuclear facilities. We discuss the Investment Agreement in more detail in *Note 15 to Consolidated Financial Statements.*

Calvert Cliffs

We own 100% of Calvert Cliffs Unit 1 (873 MW) and Unit 2 (862 MW). Unit 1 entered service in 1974 and is licensed to operate until 2034. Unit 2 entered service in 1976 and is licensed to operate until 2036.

Nine Mile Point

We own 100% of Nine Mile Point Unit 1 (620 MW) and 82% of Unit 2 (933 MW of Unit 2's total 1,138 MW). The remaining interest in Nine Mile Point Unit 2 is owned by the Long Island Power Authority (LIPA). Unit 1 entered service in 1969 and is licensed to operate until 2029. Unit 2 entered service in 1988 and is licensed to operate until 2046.

We sell 90% of our share of Nine Mile Point's output to the former owners of the plant at an average price of nearly $35 per megawatt-hour (MWH) under agreements that terminate between 2009 and 2011. The agreements are unit contingent (if the output is not available because the plant is not operating, there is no requirement to provide output from other sources). The remaining 10% of our share of Nine Mile Point's output is managed by our Global Commodities operation and sold into the wholesale market.

After termination of the power purchase agreements, a revenue sharing agreement with the former owner of the plant will begin and continue through 2021. Under this agreement, which applies only to our ownership percentage of Unit 2, a predetermined strike price is compared to the market price for electricity. If the market price exceeds the strike price, then 80% of this excess amount is shared with the former owners of the plant. The average strike price for the first year of the revenue sharing agreement is $40.75 per MWH. The strike price increases two percent annually beginning in the second year of the revenue sharing agreement. The revenue sharing agreement is unit contingent and is based on the operation of the unit.

We exclusively operate Unit 2 under an operating agreement with LIPA. LIPA is responsible for 18% of the operating costs (including decommissioning costs) and construction costs of Unit 2 and has representation on the Nine Mile Point Unit 2 management committee, which provides certain oversight and review functions.

Ginna

We own 100% of the Ginna nuclear facility. Ginna consists of a 581 MW reactor that entered service in 1970 and is licensed to operate until 2029. We sell 90% of the plant's output and capacity to the former owner for 10 years ending in 2014 at an average price of $44.00 per MWH under a long-term unit-contingent power purchase agreement. The remaining output is managed by our Global Commodities operation and sold into the wholesale market.

Qualifying Facilities and Power Projects

We hold up to a 50% voting interest in 18 operating energy projects that consist of electric generation (primarily relying on alternative fuel sources), fuel processing, or fuel handling facilities. Sixteen of the electric generation projects are considered qualifying facilities under the Public Utility Regulatory Policies Act of 1978. Each electric generating plant sells its output to a local utility under long-term contracts.

Customer Supply

We are a leading supplier of energy products and services to wholesale and retail electric and natural gas customers.

In 2008, our wholesale competitive supply operation served approximately 12,500 peak MWs of wholesale full requirements load-serving products. During 2008, our retail competitive supply activities served approximately 14,100 MW of peak load and approximately 407,000 mmBTUs of natural gas.

Our wholesale customer supply operation structures transactions that serve the full energy and capacity requirements of various customers such as distribution utilities, municipalities, cooperatives and retail aggregators that do not own sufficient generating capacity or in-house supply functions to meet their own load requirements.

Our retail customer supply operation structures transactions to supply full energy and capacity requirements and provide natural gas, transportation, and other energy products and services to retail, commercial, industrial, and governmental customers. Contracts with these customers generally extend from one to ten years, but some can be longer. To meet our customers' load-serving requirements, our merchant energy business obtains energy from various sources, including:

- our generation assets,
- exchange-traded and bilateral power and natural gas purchase agreements,
- unit contingent power purchases from generation companies,
- tolling contracts with generation companies, which provide us the right, but not the obligation, to purchase power at a price linked to the variable cost of production, including fuel, with terms that generally extend from several months to several years, but can be longer, and
- regional power pools.

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Global Commodities

Our Global Commodities operation manages contractually owned physical assets, including generation facilities, natural gas properties, international coal sourcing and freight operations, provides risk management services and uranium marketing 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 structured products and energy investment activities and includes our merchant energy business' actual hedged positions with third parties.

Structured Products

Our Global Commodities operation uses energy and energy-related commodities and contracts in order to manage our portfolio of energy purchases and sales to customers through structured transactions. Our Global Commodities operation assists customers with customized risk management products in the power, gas, coal, and freight markets (e.g., generation tolls, gas transport and storage, and global coal and freight logistics).

Energy Investments

Our Global Commodities operation has investments in energy assets that primarily include coal sourcing activities, a joint interest in an entity that owns dry bulk cargo vessels and natural gas services. We discuss each of these investments below.

Coal and International Services

We participate in global coal sourcing activities by providing coal and coal-related logistical services for the variable or fixed supply needs of global customers. We own a 50% interest in a shipping joint venture that owns and operates five freight ships for the delivery of coal and other dry bulk freight products. In 2008, we delivered approximately 25.4 million tons of coal to global customers and to our own generation fleet. Additionally, we entered into power, natural gas, freight, uranium marketing, and emissions transactions outside of the United States.

Natural Gas Services

Our Global Commodities operation includes upstream (exploration and production) and downstream (transportation and storage) natural gas operations. Our upstream activities include the acquisition, development, exploration, and exploitation of natural gas properties, as well as an approximately 28.5% interest in Constellation Energy Partners LLC (CEP), a limited liability company that we formed. CEP is principally engaged in the acquisition, development, and exploitation of natural gas properties. Our downstream activities include providing natural gas to various customers, including large utilities, commercial and industrial customers, power generators, wholesale marketers, and retail aggregators.

In 2008, 2007, and 2006, we acquired working interests in gas producing fields. We discuss these acquisitions in more detail in *Note 15 to Consolidated Financial Statements*. In 2008, we divested working interests in certain of our gas producing fields. We discuss these divestitures in more in detail in *Note 2 to Consolidated Financial Statements.*

Portfolio Management and Trading

We trade energy and energy-related contracts and commodities and deploy risk capital in the management of our portfolio. These activities are managed through daily value at risk and stop loss limits and liquidity guidelines, and could have a material impact on our financial results.

In managing our portfolio, we may terminate, restructure, or acquire contracts. Such transactions are within the normal course of managing our portfolio and may materially impact the timing of our recognition of revenues, fuel and purchased energy expenses, and cash flows.

We use both derivative and nonderivative contracts in managing our portfolio of energy sales and purchase contracts. Although a substantial portion of our portfolio is hedged, we are able to identify opportunities to deploy risk capital to increase the value of our accrual positions, which we characterize as portfolio management.

Active portfolio management is intended to allow our merchant energy business to:

- manage and hedge its fixed-price energy purchase and sale commitments,

- provide fixed-price energy commitments to customers and suppliers,
- reduce exposure to the volatility of market prices, and
- hedge fuel requirements at our non-nuclear generation facilities.

We discuss the impact of our trading activities and value at risk in more detail in *Item 7. Management's Discussion and Analysis.*

Our portfolio management and trading activities involve the use of physical commodity inventories and a variety of instruments, including:

- forward contracts (which commit us to purchase or sell energy commodities in the future),
- swap agreements (which require payments to or from counterparties based upon the difference between two prices for a predetermined contractual (notional) quantity),
- option contracts (which convey the right to buy or sell a commodity, financial instrument, or index at a predetermined price), and

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futures contracts (which are exchange traded standardized commitments to purchase or sell a commodity or financial instrument, or make a cash settlement, at a specified price and future date).

Through the third quarter of 2008, our portfolio management and trading activities increased due to the significant growth in scale of our customer supply, energy investments, and structured products operations. However, in the fourth quarter of 2008, we began to take steps to reduce the risk and scale of our portfolio management and trading activities. Energy trading activities will be scaled back and will be used primarily to hedge our generation assets and Customer Supply operations. All of these efforts will materially reduce portfolio management and trading activities' contribution to our future operating results.

Fuel Sources

Our power plants use diverse fuel sources. Our fuel mix based on capacity owned at December 31, 2008 and our generation based on actual output by fuel type in 2008 were as follows:

Fuel	**Capacity Owned**	**Generation**
Nuclear	42%	63%
Coal	30	32
Natural Gas	11	1
Oil	8	
Renewable and Alternative (1)	5	4
Dual (2)	4	

(1) *Includes solar, geothermal, hydro, waste coal, and biomass.*

(2) *Switches between natural gas and oil.*

We discuss our risks associated with fuel in more detail in *Item 7. Management's Discussion and Analysis Risk Management.*

Nuclear

The supply of fuel for nuclear generating stations includes the:

- purchase of uranium (concentrates and uranium hexafluoride),
- conversion of uranium concentrates to uranium hexafluoride,
- enrichment of uranium hexafluoride, and
- fabrication of nuclear fuel assemblies.

We have commitments that provide for sufficient quantities of uranium (concentrates and uranium hexafluoride), enrichment requirements, and the fabrication of fuel assemblies to meet expected requirements for the next several years at our Calvert Cliffs, Nine Mile Point, and Ginna nuclear generating facilities.

The nuclear fuel markets are competitive, and prices can be volatile; however, we do not anticipate any significant problems in meeting our future supply requirements.

Storage of Spent Nuclear Fuel Federal Facilities

One of the issues associated with the operation and decommissioning of nuclear generating facilities is disposal of spent nuclear fuel. There are no facilities for the reprocessing or permanent disposal of spent nuclear fuel currently in operation in the United States, and the Nuclear Regulatory Commission (NRC) has not licensed any such facilities. The Nuclear Waste Policy Act of 1982 (NWPA) required the federal government, through the Department of Energy (DOE), to develop a repository for the disposal of spent nuclear fuel and high-level radioactive waste.

As required by the NWPA, we are a party to contracts with the DOE to provide for disposal of spent nuclear fuel from our nuclear generating plants. The NWPA and our contracts with the DOE require payments to the DOE of one tenth of one cent (one mill) per kilowatt hour on nuclear electricity generated and sold to pay for the cost of long-term nuclear fuel storage and disposal. We continue to pay those fees into the DOE's Nuclear Waste Fund for our nuclear generating facilities. The NWPA and our contracts with the DOE required the DOE to begin taking possession of spent nuclear fuel generated by nuclear generating units no later than January 31, 1998.

The DOE has stated that it may not meet that obligation until 2020 at the earliest. This delay has required that we undertake additional actions and incur costs to provide on-site fuel storage at our nuclear generating facilities, including the installation of on-site dry fuel storage capacity as described in more detail below.

In 2004, complaints were filed against the federal government in the United States Court of Federal Claims seeking to recover damages caused by the DOE's failure to meet its contractual obligation to begin disposing of spent nuclear fuel by January 31, 1998. These cases are currently stayed, pending litigation in other related cases.

In connection with our purchases of Nine Mile Point and Ginna, all of the former owners' rights and obligations related to recovery of damages for DOE's failure to meet its contractual obligations were assigned to us. However, we have an obligation to reimburse the former owner of Ginna for up to $10 million of any recovered damages for such claims.

Storage of Spent Nuclear Fuel On-Site Facilities

Calvert Cliffs has a license from the NRC to operate an on-site independent spent fuel storage installation that expires in 2012. Sufficient storage capacity exists within the plant and currently installed independent spent fuel

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storage installation modules to be able to contain the full contents of the core until 2015. Efforts are currently under way to renew the independent spent fuel installation license and expand its capacity to accommodate operations through 2034. Nine Mile Point and Ginna are developing independent spent fuel storage installations at each of those facilities, which we expect to be completed in 2012 and 2010, respectively. Nine Mile Point and Ginna have sufficient storage capacity within the plant until the expected completion of the on-site independent spent fuel storage installations.

Cost for Decommissioning Nuclear Facilities

We are obligated to decommission our nuclear power plants after these plants cease operation. Our nuclear decommissioning trust funds and the investment earnings thereon are restricted to meeting the costs of decommissioning the plants in accordance with NRC regulations and relevant state requirements. We develop our decommissioning trust fund strategy based on estimates of the costs to perform the decommissioning and the timing of incurring those costs. When developing our estimates of future fund earnings, we consider our asset allocation investment strategy, rates of return earned historically, and current market conditions.

Our nuclear decommissioning trust fund assets are as follows:

At December 31, 2008	
Calvert Cliffs	$ 346.9
Nine Mile Point	460.3
Ginna	199.1
Total	$ 1,006.3

Every two years, the NRC requires us to demonstrate reasonable assurance that funds will be available to decommission the sites. Our next NRC submittal will occur in March 2009. Due to recent declines in the financial markets, the fair value of our trust funds decreased $324.5 million, net of $18.7 million of contributions made to the trusts, during 2008. As a result of this decline, the NRC may require us to provide additional financial assurance for certain of our plants' decommissioning trusts. Previously, we have provided parental guarantees as additional financial assurance, but alternatively, the NRC could require other forms of financial assurance, including letters of credit, surety bonds, or additional cash contributions to the trusts.

Decommissioning activities are currently projected to be staged through 2083. Any changes in the costs or timing of decommissioning activities, or changes in the fund earnings, could affect the adequacy of the funds to cover the decommissioning of the plants, and if there were to be a shortfall, we would have to provide additional funding.

Calvert Cliffs

When BGE transferred all of its nuclear generating assets to our merchant energy business, it also transferred the funds accumulated to pay for decommissioning Calvert Cliffs. In March 2008, Constellation Energy, BGE, and a Constellation Energy affiliate entered into a settlement agreement with the State of Maryland, the Public Service Commission of Maryland (Maryland PSC), and certain State of Maryland officials. The settlement agreement became effective on June 1, 2008. Pursuant to the terms of the settlement agreement, BGE customers will be relieved of the potential future liability for decommissioning Calvert Cliffs Unit 1 and Unit 2. BGE will continue to collect the $18.7 million annual nuclear decommissioning charge from all electric customers through 2016 and continue to rebate this amount to residential electric customers, as previously required by Maryland Senate Bill 1 which was enacted in June 2006. We discuss the Maryland settlement agreement in more detail in *Note 2 to Consolidated Financial Statements.*

Nine Mile Point

The sellers of Nine Mile Point transferred a $441.7 million decommissioning trust fund to us at the time of sale. In return, we assumed all liability for the costs to decommission Unit 1 and 82% of the costs to decommission Unit 2.

Ginna

The seller of Ginna transferred $200.8 million in decommissioning funds to us. In return, we assumed all liability for the costs to decommission the unit.

Coal

We purchase the majority of our coal for electric generation under supply contracts with mining operators, and we acquire the remainder in the spot or forward coal markets. We believe that we will be able to renew supply contracts as they expire or enter into contracts with other coal suppliers. Our primary coal-burning facilities have the following requirements:

	Approximate Annual Coal Requirement (tons)
Brandon Shores Units 1 and 2 (combined)	3,500,000
C. P. Crane Units 1 and 2 (combined)	850,000
H. A. Wagner Units 2 and 3 (combined)	1,100,000

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We receive coal deliveries to these facilities by rail and barge. Over the past few years, we expanded our coal sources through a variety of methods, including restructuring our rail contracts, increasing the range of coals we can consume, and finding potential other coal supply sources including limited shipments from various international sources. While we primarily use coal produced from mines located in central and northern Appalachia, we are capable of switching to coal from the Western United States or imported coal to manage our coal supply. The timely delivery of coal together with the maintenance of appropriate levels of inventory is necessary to allow for continued, reliable generation from these facilities.

As discussed in the *Environmental Matters* section, our Maryland coal-fired generating facilities must comply with the requirements of the Maryland Healthy Air Act (HAA), which requires reduction of sulfur dioxide (SO_2), nitrogen oxide (NO_x), and mercury emissions. We are installing emission control equipment at each of our Maryland coal-fired facilities. The new equipment and HAA emission reduction requirements will influence the characteristics of the coals that we burn in the future.

All of the Conemaugh and Keystone plants' annual coal requirements are purchased by the plant operators from regional suppliers on the open market. The sulfur restrictions on coal are approximately 2.3% for the Keystone plant and approximately 5.3% for the Conemaugh plant. The Keystone owners are installing emission control equipment at Keystone which will result in a sulfur restriction of 5.3%. Although we expected the Keystone and Conemaugh facilities would have to comply with Pennsylvania mercury regulations beginning in 2010, in January 2009, the Pennsylvania Commonwealth Court held that those regulations were invalid based on a February 2008 federal court decision that struck down the Federal Clean Air Mercury Rule (CAMR). The Commonwealth of Pennsylvania has indicated that it may appeal the court's decision. At this time, we cannot predict the ultimate outcome of these proceedings or its effect on our financial results.

The annual coal requirements for the ACE, Jasmin, and Poso plants, which are located in California, are supplied under contracts with mining operators. These plants are restricted to coal with sulfur content less than 4.0%.

The primary fuel source for Panther Creek and Colver generating facilities is waste coal. These facilities meet their annual requirements through existing reserves of mined and processed waste coal and through supply agreements with various terms.

All of our coal requirements reflect historical generating levels. The actual fuel quantities required can vary substantially from historical levels depending upon the relationship between energy prices and fuel costs, weather conditions, and operating requirements. However, we believe that we will be able to obtain adequate quantities of coal to meet our requirements.

Gas

We purchase natural gas, storage capacity, and transportation, as necessary, for electric generation at certain plants. Some of our gas-fired units can use residual fuel oil or distillates instead of gas. Gas is purchased under contracts with suppliers on the spot market and forward markets, including financial exchanges and under bilateral agreements. The actual fuel quantities required can vary substantially from year to year depending upon the relationship between energy prices and fuel costs, weather conditions, and operating requirements. However, we believe that we will be able to obtain adequate quantities of gas to meet our requirements.

Oil

From 2006 through 2008, our requirements for residual fuel oil (No. 6) amounted to less than 0.5 million barrels of low-sulfur oil per year. Deliveries of residual fuel oil are made from the suppliers' Baltimore Harbor and Philadelphia marine terminals for distribution to the various generating plant locations. Also, based on normal burn practices, we require approximately 8.0 million to 11.0 million gallons of distillates (No. 2 oil and kerosene) annually, but these requirements can vary substantially from year to year depending upon the relationship between energy prices and fuel costs, weather conditions, and operating requirements. Distillates are purchased from the suppliers' Baltimore truck terminals for distribution to the various generating plant locations. We have contracts with various suppliers to purchase oil at spot prices, and for future delivery, to meet our requirements.

Competition

We encounter competition from companies of various sizes, having varying levels of experience, financial and human resources, and differing strategies.

We face competition in the market for energy, capacity, and ancillary services. In our merchant energy business, we compete with international, national, and regional full-service energy providers, merchants, and producers to obtain competitively priced supplies from a variety of sources and locations, and to utilize efficient transmission, transportation, or storage. We principally compete on the basis of price, customer service, reliability, and availability of our products.

With respect to power generation, we compete in the operation of energy-producing projects, and our competitors in this business are both domestic and international organizations, including various utilities, industrial companies and independent power producers (including affiliates of utilities, financial investors, and banks), some of which have greater financial resources.

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States are considering different types of regulatory initiatives concerning competition in the power and gas industry, which makes a competitive assessment difficult. Many states continue to support or expand retail competition and industry restructuring. Other states that were considering deregulation have slowed their plans or postponed consideration of deregulation. In addition, certain previously restructured states are considering re-regulation of their retail markets. While there is significant activity in this area, we believe there is adequate growth potential in the current deregulated market.

As the market for commercial, industrial, and governmental energy supply continues to grow, we have experienced increased competition on a regional basis in our retail competitive supply activities. The increase in retail competition and the impact of wholesale power prices compared to the rates charged by local utilities has, in certain circumstances, reduced the margins that we realize from our customers. However, we believe that our experience and expertise in assessing and managing risk and our strong focus on customer service will help us to remain competitive during volatile or otherwise adverse market circumstances.

Merchant Energy Operating Statistics

	2008	2007	2006
Gross Margin *(In millions)*			
Generation	**$ 1,956**	$ 1,700	$ 1,490
Customer Supply	**765**	889	764
Global Commodities	**260**	654	656
Total Gross Margin	**$ 2,981**	$ 3,243	$ 2,910
Generation *(In millions)* MWH *	**50.9**	51.6	59.1

*

Includes output from gas-fired plants until sale in December 2006.

Operating statistics do not reflect the elimination of intercompany transactions.

Baltimore Gas and Electric Company

BGE is an electric transmission and distribution utility company and a gas distribution utility company with a service territory that covers the City of Baltimore and all or part of ten counties in central Maryland. BGE is regulated by the Maryland PSC and Federal Energy Regulatory Commission (FERC) with respect to rates and other aspects of its business.

BGE's electric service territory includes an area of approximately 2,300 square miles. There are no municipal or cooperative wholesale customers within BGE's service territory. BGE's gas service territory includes an area of approximately 800 square miles.

BGE's electric and gas revenues come from many customers residential, commercial, and industrial.

Electric Business

Electric Competition

Deregulation

Maryland has implemented electric customer choice and competition among electric suppliers. As a result, all customers can choose their electric energy supplier. While BGE does not sell electricity to all customers in its service territory, BGE continues to deliver electricity to all customers and provides meter reading, billing, emergency response, and regular maintenance.

Standard Offer Service

BGE is obligated to provide market-based standard offer service (SOS) to all of its electric customers who elect not to select a competitive energy supplier. The SOS rates charged recover BGE's wholesale power supply costs and include an administrative fee. The administrative fee includes a shareholder return component and an incremental cost component. As discussed in *Item 7. Management's Discussion and Analysis Regulated Electric Business* section, BGE resumed collection of the shareholder return portion of the residential SOS administrative charge, which had been eliminated under Maryland Senate Bill 1, from June 1, 2008 through May 31, 2010 without having to rebate it to all residential electric customers. BGE will cease collecting the residential shareholder return component again from June 1, 2010 through December 31, 2016.

Bidding to supply BGE's SOS occurs from time to time through a competitive bidding process approved by the Maryland PSC. Successful bidders, which may include subsidiaries of Constellation Energy, execute contracts with BGE for varying terms.

Commercial and Industrial Customers

BGE is obligated to provide several variations of SOS to commercial and industrial customers depending on customer load.

For those commercial and industrial customers for which SOS originally had been scheduled to expire at the end of May 2007, BGE must continue to provide SOS indefinitely on substantially the same terms as under the then existing service, except that wholesale bidding for service to some customers will be conducted more frequently.

BGE's obligation to provide SOS to its largest commercial and industrial customers expired in 2005. However, BGE continues to provide an hourly priced SOS to those customers.

Residential Customers

As a result of the November 1999 Maryland PSC order regarding the deregulation of electric generation in Maryland, BGE's residential electric base rates were frozen until July 2006. However, Maryland Senate Bill 1, enacted in June 2006, delayed full market rates for some residential customers until June 2007, with the remainder of residential customers going to full market rates in January 2008. Pursuant to a settlement agreement entered into with the State of Maryland, the Maryland PSC, and certain Maryland officials in March 2008, BGE provided residential electric customers approximately $189 million in the form of a one-time $170 per customer rate credit. We discuss the Maryland settlement agreement in more detail in *Note 2 to Consolidated Financial Statements* and the market risk of our regulated electric business in more detail in *Item 7. Management' Discussion and Analysis Risk Management* section.

Electric Load Management

BGE has implemented various programs for use when system-operating conditions or market economics indicate that a reduction in load would be beneficial. These programs include:

two options for commercial and industrial customers to reduce their electric loads,

air conditioning and heat pump control for residential and commercial customers through both programmable thermostats and load control devices, and

residential water heater control.

These programs generally take effect on summer days when demand and/or wholesale prices are relatively high and had the effect of reducing BGE's system peak load by 236 MW during the summer period in 2008.

BGE is developing other programs designed to help manage its peak demand, improve system reliability and improve service to customers by giving customers greater control over their energy use.

BGE has concluded an advanced metering pilot program and is utilizing the results to develop a strategy for full deployment of the advanced metering program. BGE is also continuing a pilot program to evaluate pricing options designed to incentivize customers to

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decrease energy use during peak demand periods. Additionally, in 2007, BGE initiated a limited conservation program that provides incentives to customers to use energy efficient products and to take other actions to conserve energy. The Maryland PSC recently approved a full portfolio of conservation programs for implementation in 2009 as well as a customer surcharge to recover the associated costs. We also discuss the demand response initiatives in *Item 7. Management's Discussion and Analysis Regulation Maryland Maryland PSC* section.

Transmission and Distribution Facilities

BGE maintains approximately 250 substations and approximately 1,300 circuit miles of transmission lines throughout central Maryland. BGE also maintains approximately 24,500 circuit miles of distribution lines. The transmission facilities are connected to those of neighboring utility systems as part of PJM Interconnection (PJM). Under the PJM Tariff and various agreements, BGE and other market participants can use regional transmission facilities for energy, capacity, and ancillary services transactions, including emergency assistance.

We discuss various FERC initiatives relating to wholesale electric markets in more detail in *Item 7. Management's Discussion and Analysis Federal Regulation* section.

Electric Operating Statistics

	2008	**2007**	**2006**
Revenues *(In millions)*			
Residential	**$ 1,695.9**	$ 1,514.9	$ 1,092.1
Commercial			
Excluding Delivery Service Only	**604.0**	577.4	733.4
Delivery Service Only	**222.8**	217.0	149.4
Industrial			
Excluding Delivery Service Only	**31.3**	31.6	46.8
Delivery Service Only	**27.1**	27.8	26.2
System Sales and Deliveries	**2,581.1**	2,368.7	2,047.9
Other (A)	**98.6**	87.0	68.0
Total	**$ 2,679.7**	$ 2,455.7	$ 2,115.9
Distribution Volumes *(In thousands)* MWH			
Residential	**13,023**	13,365	12,886
Commercial			
Excluding Delivery Service Only	**3,957**	4,364	6,325
Delivery Service Only	**11,739**	11,921	9,392
Industrial			
Excluding Delivery Service Only	**242**	287	467
Delivery Service Only	**3,002**	3,175	2,988
Total	**31,963**	33,112	32,058
Customers *(In thousands)*			
Residential	**1,108.5**	1,103.1	1,093.3
Commercial	**117.6**	116.7	115.5
Industrial	**5.3**	5.5	5.2
Total	**1,231.4**	1,225.3	1,214.0

(A) Primarily includes network integration transmission service revenues, late payment charges, miscellaneous service fees, and tower leasing revenues.

Operating statistics do not reflect the elimination of intercompany transactions.
"Delivery service only" refers to BGE's delivery of electricity that was purchased by the customer from an alternate supplier.

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Gas Business

The wholesale price of natural gas as a commodity is not subject to regulation. All BGE gas customers have the option to purchase gas from alternative suppliers, including subsidiaries of Constellation Energy. BGE continues to deliver gas to all customers within its service territory. This delivery service is regulated by the Maryland PSC.

BGE also provides customers with meter reading, billing, emergency response, regular maintenance, and balancing services.

Approximately 50% of the gas delivered on BGE's distribution system is for customers that purchase gas from alternative suppliers. These customers are charged fees to recover the costs BGE incurs to deliver the customers' gas through our distribution system.

A market-based rates incentive mechanism applies to customers that buy their gas from BGE. Under this mechanism, BGE's 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 BGE's actual cost and the market index is shared equally between shareholders and customers. BGE must secure fixed-price contracts for at least 10%, but not more than 20%, of forecasted system supply requirements for flowing (i.e., non-storage) gas for the November through March period. These fixed-price contracts are not subject to sharing under the market-based rates incentive mechanism.

BGE meets its natural gas load requirements through firm pipeline transportation and storage entitlements.

BGE's current pipeline firm transportation entitlements to serve its firm loads are 338,053 dekatherms (DTH) per day.

BGE's current maximum storage entitlements are 254,697 DTH per day. To supplement its gas supply at times of heavy winter demands and to be available in temporary emergencies affecting gas supply, BGE has:

- a liquefied natural gas facility for the liquefaction and storage of natural gas with a total storage capacity of 1,092,977 DTH and a daily capacity of 311,500 DTH, and
- a propane air facility and a mined cavern with a total storage capacity equivalent to 564,200 DTH and a daily capacity of 85,000 DTH.

BGE has under contract sufficient volumes of propane for the operation of the propane air facility and is capable of liquefying sufficient volumes of natural gas during the summer months for operations of its liquefied natural gas facility during peak winter periods.

BGE historically has been able to arrange short-term contracts or exchange agreements with other gas companies in the event of short-term disruptions to gas supplies or to meet additional demand.

BGE also participates in the interstate markets by releasing pipeline capacity or bundling pipeline capacity with gas for off-system sales. Off-system gas sales are low-margin direct sales of gas to wholesale suppliers of natural gas. Earnings from these activities are shared between shareholders and customers. BGE makes these sales as part of a program to balance its supply of, and cost of, natural gas.

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Gas Operating Statistics

	2008	2007	2006
Revenues *(In millions)*			
Residential			
Excluding Delivery Service Only	**$ 567.8**	$ 552.0	$ 490.2
Delivery Service Only	**19.0**	19.0	20.6
Commercial			
Excluding Delivery Service Only	**161.8**	154.1	148.9
Delivery Service Only	**46.4**	41.2	35.9
Industrial			
Excluding Delivery Service Only	**8.1**	7.8	7.5
Delivery Service Only	**14.5**	22.1	19.3
System Sales and Deliveries	**817.6**	796.2	722.4
Off-System Sales	**197.7**	157.4	168.6
Other	**8.7**	9.2	8.5
Total	**$ 1,024.0**	$ 962.8	$ 899.5
Distribution Volumes *(In thousands)* DTH			
Residential			
Excluding Delivery Service Only	**37,675**	39,199	33,019
Delivery Service Only	**4,119**	4,310	3,948
Commercial			
Excluding Delivery Service Only	**12,205**	12,464	11,683
Delivery Service Only	**29,289**	30,367	25,695
Industrial			
Excluding Delivery Service Only	**650**	658	604
Delivery Service Only	**18,432**	17,897	20,325
System Sales and Deliveries	**102,370**	104,895	95,274
Off-System Sales	**18,782**	19,963	19,738
Total	**121,152**	124,858	115,012
Customers *(In thousands)*			
Residential	**605.0**	602.3	597.1
Commercial	**42.8**	42.7	42.3
Industrial	**1.1**	1.2	1.2
Total	**648.9**	646.2	640.6

Operating statistics do not reflect the elimination of intercompany transactions.
"Delivery service only" refers to BGE's delivery of gas that was purchased by the customer from an alternate supplier.

Franchises

BGE has nonexclusive electric and gas franchises to use streets and other highways that are adequate and sufficient to permit it to engage in its present business. Conditions of the franchises are satisfactory.

Other Nonregulated Businesses

UniStar Nuclear

In 2005, we formed UniStar Nuclear, LLC (UniStar), a joint enterprise with AREVA NP, Inc., (AREVA) to introduce the advanced design Evolutionary Power Reactor to the U.S. market. Upon conversion to U.S. electrical standards, the technology will be known as the U.S. EPR.

In August 2007, we formed a joint venture, UniStar Nuclear Energy, LLC (UNE) with EDF. We have a 50% ownership interest in this joint venture to develop, own, and operate new nuclear projects in the United States and Canada. EDF initially invested $350 million of cash in UNE, and we contributed our interest in UniStar and other UniStar-related assets, which had a book value of $49 million, and the right to develop new nuclear projects at our existing nuclear plant locations. In the event that the joint venture is terminated, the remaining equity of UNE, after certain expenses, will be divided equally between Constellation Energy and EDF pursuant to the joint venture agreement.

In 2008, EDF contributed an additional $175 million to UNE based upon reaching certain licensing milestones. EDF will contribute up to an additional $100 million to UNE, for a total of $625 million, upon reaching additional licensing

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milestones after which future funding will be made on a pro rata basis. In 2008, we contributed additional assets which had a book value of $2 million.

In connection with this joint venture, in 2007 we entered into an investor agreement with EDF under which EDF is limited to owning no more than 9.9% of our outstanding common stock until July 2012 and is required to vote any shares of our common stock owned by it in the manner recommended by our Board of Directors and not take any actions that seek control of Constellation Energy until July 2012. In connection with the execution of the Investment Agreement in December 2008, the investor agreement was amended to enable EDF, in connection with certain extraordinary events, such as a change in control transaction, to acquire shares of our common stock above the 9.9% limitation and to vote its shares at its discretion. The amended investor agreement also provides that following EDF's acquisition of 49.99% of our nuclear generation and operation business, EDF will have the right to appoint one director to our Board of Directors. As of December 31, 2008, EDF owned approximately 8.5% of our outstanding common stock.

Energy Projects and Services

We offer energy projects and services to large commercial, industrial and governmental customers. These energy products and services include:

- designing, constructing, and operating renewable energy, heating, cooling, and cogeneration facilities,
- water and energy savings projects and performance contracting,
- energy consulting and procurement services,
- services to enhance the reliability of individual electric supply systems, and
- customized financing alternatives.

Home Products and Gas Retail Marketing

We offer services to customers in Maryland including:

- home improvements,
- the service of heating, air conditioning, plumbing, electrical, and indoor air quality systems, and
- the sale of natural gas to residential customers.

Consolidated Capital Requirements

Our total capital requirements for 2008 were $2.2 billion. Of this amount, $1.7 billion was used in our nonregulated businesses and $0.5 billion was used in our regulated business. We estimate our total capital requirements will be $1.7 billion in 2009.

We continuously review and change our capital expenditure programs, so actual expenditures may vary from the estimate above. We discuss our capital requirements further in *Item 7. Management's Discussion and Analysis Capital Resources* section.

Environmental Matters

The development (involving site selection, environmental assessments, and permitting), construction, acquisition, and operation of electric generating and distribution facilities are subject to extensive federal, state, and local environmental and land use laws and regulations. From the beginning phases of development to the ongoing operation of existing or new electric generating and distribution facilities, our activities involve compliance with diverse laws and regulations that address emissions and impacts to air and water, protection of natural and cultural resources, and chemical and waste handling and disposal.

We continuously monitor federal, state, and local environmental initiatives to determine potential impacts on our financial results. As new laws or regulations are promulgated, we assess their applicability and implement the necessary modifications to our facilities or their operation to maintain ongoing compliance. Our capital expenditures were approximately $750 million during the five-year period 2004-2008 to comply with existing environmental standards and regulations. Our estimated environmental capital requirements for the next three years are approximately $330 million in 2009, $50 million in 2010, and $25 million in 2011.

Air Quality

Federal

The Clean Air Act created the basic framework for the federal and state regulation of air pollution.

National Ambient Air Quality Standards (NAAQS)

The NAAQS are federal air quality standards authorized under the Clean Air Act that establish maximum ambient air concentrations for the following specific pollutants: ozone (smog), carbon monoxide, lead, particulates, SO_2, and nitrogen dioxides.

In order for states to achieve compliance with the NAAQS, the Environmental Protection Agency (EPA) adopted the Clean Air Interstate Rule (CAIR) in March 2005 to further reduce ozone and fine particulate pollution by addressing the interstate transport of SO_2 and NO_x emissions from fossil fuel-fired generating facilities located primarily in the Eastern United States.

In December 2008, the United States Court of Appeals for the District of Columbia Circuit reversed its July 2008 decision to effectively repeal CAIR and remanded the issue to the EPA for reconsideration. As a result, the requirements of CAIR remain in effect until the EPA takes further action. We cannot predict what additional judicial, legislative or regulatory actions will be taken in response to the court's decision or the EPA's reconsideration of CAIR or whether such actions may affect our financial results. We do not believe that the repeal of CAIR would result in a material change to our emissions reduction plan in Maryland as the emissions reduction requirements of Maryland's HAA and Clean

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Power Rule (CPR) are more stringent and apply sooner than those under CAIR. However, future changes in CAIR could affect the market prices of SO_2 and NO_x emission allowances, which could in turn affect our financial results. We discuss the impact that these rulings had on our 2008 results in *Item 7. Management's Discussion and Analysis Merchant Energy Business* section. We discuss these rulings in more detail in the *Note 12 to Consolidated Financial Statements.*

In March 2008, the EPA adopted a stricter NAAQS for ozone. We are unable to determine the impact that complying with the stricter NAAQS for ozone will have on our financial results until the states in which our generating facilities are located adopt plans to meet the new standards.

In December 2006, the United States Court of Appeals for the District of Columbia Circuit ruled that a requirement to impose fees on emissions sources based on the previous ozone standard (Section 185 fees), which had been rescinded by the EPA in May 2005, remained applicable retroactive to November 2005 and remanded the issue to the EPA for reconsideration. A petition to the United States Supreme Court to hear an appeal was denied in January 2008. The EPA has announced that it intends to propose regulations to address how Section 185 fees will be handled. In addition, the exact method of computing these fees has not been established and will depend in part on state implementation regulations that have not been proposed. Consequently, we are unable to estimate the ultimate financial impact of this matter in light of the uncertainty surrounding the anticipated EPA and state rulemakings. However, the final resolution of this matter, and any fees that are ultimately assessed could have a material impact on our financial results.

In September 2006, the EPA adopted a stricter NAAQS for particulate matter. We are unable to determine the impact that complying with the stricter NAAQS for particulate matter will have on our financial results until the states in which our generating facilities are located adopt plans to meet the new standard.

Hazardous Air Emissions

In March 2005, the EPA finalized the CAMR to reduce the emissions of mercury from coal-fired facilities through a market-based cap and trade program. CAMR was to affect all coal or waste coal fired boilers at our generating facilities. However, in February 2008, the United States Court of Appeals for the District of Columbia Circuit struck down CAMR. In response to this decision, the EPA recently announced that it intends to develop new mercury emission standards under the CAA. Any new standards that require the installation of additional emissions control technology beyond what is required under Maryland's Healthy Air Act and Clean Power Rule, which are discussed below, may require us to incur additional costs, which could have a material effect on our financial results.

New Source Review

In connection with its enforcement of the CAA's new source review requirements, in 2000, the EPA requested information relating to modifications made to our Brandon Shores, Crane, and Wagner plants located in Maryland. The EPA also sent similar, but narrower, information requests to two of our newer Pennsylvania waste-coal burning plants in which we have an ownership interest. We responded to the EPA in 2001, and as of the date of this report the EPA has taken no further action.

As discussed in *Note 12 to Consolidated Financial Statements*, in January 2009, the EPA issued a Notice of Violation to one of our subsidiaries alleging that the Keystone plant located in Pennsylvania, of which we own a 21% interest, performed various capital projects without complying with the new source review requirements.

Based on the level of emissions control that the EPA and states are seeking in new source review enforcement actions, we believe that material additional costs and penalties could be incurred, and planned capital expenditures could be accelerated, if the EPA was successful in any future actions regarding our facilities.

State

Maryland has adopted the HAA and the CPR, which establish annual SO_2, NO_x, and mercury emission caps for specific coal-fired units in Maryland, including units located at three of our facilities. The requirements of the HAA and the CPR for $SO_{2,}$ $NO_{x,}$ and mercury emissions are more stringent and apply sooner than those required under CAIR. In addition, Pennsylvania had adopted regulations requiring coal-fired generating facilities located in Pennsylvania to reduce mercury emissions. As we discuss in the *Coal* section, a Pennsylvania court held that those regulations were invalid in January 2009.

Several other states in the northeastern U.S. continue to consider more stringent and earlier SO_2, NO_x, and mercury emissions reductions than those required under CAIR or CAMR.

Maryland also is in the process of considering changes to its current opacity regulations consistent with its commitment to resolve long-standing industry concerns about the regulations' continuous compliance requirements. However, we are not yet able to determine the final form these revised regulations will take or the impact such revised regulations could have on our business or financial results.

Capital Expenditure Estimates Air Quality

We expect to incur additional environmental capital spending as a result of complying with the air quality laws and regulations discussed above. To comply with HAA and CPR, we will install additional air emission control equipment at our coal-fired generating facilities in Maryland and at our co-owned coal-fired facilities in Pennsylvania to meet air quality standards. We include in our estimated environmental capital requirements capital spending for these air quality projects, which we expect will be approximately $295 million in 2009, $40 million in 2010, $15 million in 2011 and $30 million from 2012-2013.

Our estimates are subject to significant uncertainties including the timing of any additional federal and/or state regulations or legislation, such as any regulations adopted by the EPA in response to the court decision striking down CAMR, the implementation timetables for such regulation or legislation, and the specific amount of emissions reductions that will be required at our facilities. As a result, we cannot predict our capital spending or the scope or timing of these projects with certainty, and the actual expenditures, scope, and timing could differ significantly from our estimates.

We believe that the additional air emission control equipment we plan to install will meet the emission reduction requirements under HAA and CPR. If additional emission reductions still are required, we will assess our various compliance alternatives and their related costs, and although we cannot yet estimate the additional costs we may incur, such costs could be material.

Global Climate Change

Although uncertainty remains as to the nature and timing of greenhouse gas emissions regulation, there is an increasing likelihood that such regulation will occur at the federal and/or state level. In the event that greenhouse gas emissions reduction legislation or regulations are enacted, we will assess our various compliance alternatives, which may include installation of additional environmental controls, modification of operating schedules, or the closure of one or more of our coal-fired generating facilities. Any compliance costs we incur could have a material impact on our financial results.

However, to the extent greenhouse gas emissions are regulated through a federal, mandatory cap and trade greenhouse gas emissions program, we believe our business could also benefit. Our generation fleet currently has a carbon dioxide (CO_2) emission rate lower than the industry average with more than 60% of the fleet's output coming from low CO_2 emitting nuclear and hydroelectric plants. Our global commodities operation has experience trading in the markets for emissions allowances and renewable energy credits.

In accordance with HAA requirements, Maryland became a full participant in the Northeast Regional Greenhouse Gas Initiative (RGGI) in April 2007. Under RGGI, the Maryland Department of the Environment auctions 100% of CO_2 allowances associated with Maryland's power plants, which include plants owned by us. Auctions occurred in September and December 2008. Although we did not incur material costs in these auctions, we could incur material costs in the future to purchase CO_2 allowances necessary to offset emissions from our plants.

In addition, California has adopted regulations requiring our generating facilities in California to submit greenhouse gas emissions data to the state, which the state intends to use to develop a plan to reduce greenhouse gas emissions.

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

Water Quality

The Clean Water Act established the basic framework for federal and state regulation of water pollution control and requires facilities that discharge waste or storm water into the waters of the United States to obtain permits.

Water Intake Regulations

The Clean Water Act requires cooling water intake structures to reflect the best technology available for minimizing adverse environmental impacts. In July 2004, the EPA published final rules under the Clean Water Act for existing facilities that establish performance standards for meeting the best technology available for minimizing adverse environmental impacts. We currently have seven facilities affected by the regulation. In January 2007, the United States Court of Appeals for the Second Circuit ruled that the EPA's rule did not properly implement the Clean Water Act requirements in a number of areas and remanded the rule to the EPA for reconsideration.

In response to this ruling, in July 2007, the EPA suspended the second phase of the regulations pending further rulemaking and directed the permitting authorities to establish controls for cooling water intake structures that reflect the best technology available for minimizing adverse environmental impacts. In December 2008, the United States Supreme Court heard an appeal of the Second Circuit's decision relating to the application of cost-benefit analysis to best technology available decisions and a decision is expected in 2009.

In addition, the EPA is expected to propose new regulations, but the timing of those regulations is uncertain. We will evaluate our compliance options in light of the Supreme Court and Second Circuit decisions, the EPA's July 2007 order and any subsequent EPA proposals. At this time, we cannot estimate our compliance costs, but they could be material.

Hazardous and Solid Waste

We discuss proceedings relating to compliance with the Comprehensive Environmental Response, Compensation and Liability Act in *Note 12 to Consolidated Financial Statements*.

Our coal-fired generating facilities produce approximately two and a half million tons of combustion by-products ("ash") each year. The EPA announced in 2007 its intention to develop national standards to regulate this material as a non-hazardous waste, and has been developing or considering regulations governing the placement of ash in landfills, surface impoundments, sand/gravel surface mines and coal mines. In addition, the Maryland Department of the Environment finalized regulations governing the disposal, storage, use and placement of ash in December 2008. Federal regulation has the potential to result in additional requirements. Depending on the scope of any final federal requirements, our compliance costs could be material.

As a result of these regulatory proposals and our current ash generation projections, we are exploring our options for the management of ash, including construction of an ash placement facility. Over the next five years, we estimate that our capital expenditures for this project will be approximately $60 million. Our estimates are subject to significant uncertainties, including the timing of any regulatory change, its implementation timetable, and the scope of the final requirements. As a result, we cannot predict our capital spending or the scope and timing of this project with certainty, and the actual expenditures, scope and timing could differ significantly from our estimates.

Employees

In December 2008, we announced a global workforce reduction of approximately 8%. We completed a portion of this reduction in 2008 with the remainder expected to occur in 2009 in connection with our efforts to sell our upstream gas properties and finalize the sale of a majority of our international commodities operation and our gas trading operation.

Constellation Energy and its subsidiaries had approximately 10,200 employees at December 31, 2008. At the Nine Mile Point facility, approximately 500 employees are represented by the International Brotherhood of Electrical Workers, Local 97. The labor contract with this union expires in June 2011. We believe that our relationship with this union is satisfactory, but there can be no assurances that this will continue to be the case.

Available Information

Constellation Energy maintains a website at constellation.com where copies of our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and any amendments may be obtained free of charge. These reports are posted on our website the same day they are filed with the SEC. The SEC maintains a website (sec.gov), where copies of our filings may be obtained free of charge. The website address for BGE is bge.com. These website addresses are inactive textual references, and the contents of these websites are not part of this Form 10-K.

In addition, the website for Constellation Energy includes copies of our Corporate Governance Guidelines, Principles of Business Integrity, Corporate Compliance Program, Insider Trading Policy, Policy and Procedures with respect to Related Person Transactions, Information Disclosure Policy, and the charters of the Audit, Compensation and Nominating and Corporate Governance Committees of the Board of Directors. Copies of each of these documents may be printed from our website or may be obtained from Constellation Energy upon written request to the Corporate Secretary.

The Principles of Business Integrity is a code of ethics that applies to all of our directors, officers, and employees, including the chief executive officer, chief financial officer, and chief accounting officer. We will post any amendments to, or waivers from, the Principles of Business Integrity applicable to our chief executive officer, chief financial officer, or chief accounting officer on our website.

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Item 1A. Risk Factors

You should consider carefully the following risks, along with the other information contained in this Form 10-K. The risks and uncertainties described below are not the only ones that may affect us. Additional risks and uncertainties also may adversely affect our business and operations including those discussed in Item 7. Management's Discussion and Analysis. If any of the following events actually occur, our business and financial results could be materially adversely affected.

Economic conditions and instability in the financial markets could negatively impact our business.

Our operations are affected by local, national, and worldwide economic conditions. The consequences of a prolonged recession may include a lower level of economic activity and uncertainty regarding energy prices and the capital and commodity markets. A lower level of economic activity might result in a decline in energy consumption, an increase in customers' inability to pay their accounts, and lower commodity prices. These impacts may adversely affect our financial results and future growth.

Instability in the financial markets, as a result of recession or otherwise, may affect the cost of capital and our ability to raise capital. We rely on the capital markets, as well as the banking and commercial paper markets to the extent available, to meet our financial commitments and short-term liquidity needs if internal funds are not available from our operations. We also use letters of credit issued under our credit facilities to support our operations. Disruptions in the capital and credit markets as a result of uncertainty, reduced alternatives, or failures of significant financial institutions could adversely affect our access to liquidity needed for our businesses, including our ability to secure credit facilities and refinance debt that comes due, and our ability to complete other alternatives we are exploring. In addition, such disruptions could adversely affect our ability to draw on our credit facilities. Our access to funds under those credit facilities is dependent on the ability of the banks that are parties to the facilities to meet their funding commitments. Those banks may not be able to meet their funding commitments to us if they experience shortages of capital and liquidity or if they experience excessive volumes of borrowing requests from borrowers within a short period of time. The disruptions in capital and credit markets may also result in higher interest rates on publicly issued debt securities and increased costs associated with commercial paper borrowing and under bank credit facilities.

Any disruptions could require us to take measures to conserve cash until the markets stabilize or until alternative credit arrangements or other funding for our business needs can be arranged. Such measures could include deferring capital expenditures, further changing our strategies to reduce collateral-posting requirements, and reducing or eliminating future dividend payments or other discretionary uses of cash. The inability to obtain the liquidity needed to meet our business requirements, or to obtain such liquidity on terms that are favorable to us, would have a material adverse effect on our business, results of operations and financial condition. If entities with which we do business are unable to raise capital or access the credit markets, they may be unable to perform their obligations or make payments under agreements we have with them. Defaults by these entities may have an adverse effect on our financial results.

We may be unable to execute our strategies to improve liquidity and reduce invested capital.

In an effort to improve our liquidity and reduce our business risk, we are undertaking a number of strategic initiatives to reduce capital spending and ongoing expenses, scale down the expected variability in long-term earnings and short-term collateral usage, and limit our exposure to business activities that require contingent capital support. In connection with these efforts, we have entered into agreements to sell the majority of our international commodities operation and our gas trading operation and we have signed a letter of intent to enter into a gas supply arrangement to support our retail gas activities. While we have entered into these agreements, they remain subject to regulatory approval and other standard closing conditions and we cannot provide any assurance that these sales or other sales will be completed.

In addition, if we cannot execute on our strategic initiatives successfully, including completing the sales of our international commodities operation and our gas trading operation, our liquidity will be adversely affected, which would have a material adverse effect on our business, results of operations, and financial condition.

A downgrade in our credit ratings could negatively affect our ability to access capital and/or operate our wholesale and retail competitive supply businesses.

We rely on access to capital markets as a source of liquidity for capital requirements not satisfied by operating cash flows. If any of our credit ratings were to be downgraded, especially below investment grade, our ability to raise capital on favorable terms, including in the commercial paper markets, if available, could be hindered, and our borrowing costs would increase. Additionally, the business prospects of our wholesale and retail competitive supply businesses, which in many cases rely on the creditworthiness of Constellation Energy, would be negatively impacted. In this regard, we have certain agreements that contain provisions that would require us to post additional collateral upon a credit rating downgrade. Based on market conditions and contractual obligations at the time of a downgrade, we could be required to post collateral in an amount that exceeds our available liquidity. Also, a credit rating downgrade would

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require us to grant a lien on certain of our generation assets and pledge our ownership interest in our nuclear generation business to the lenders under our credit facilities following the closing or termination of our investment agreement with EDF. Some of the factors that affect credit ratings are cash flows, liquidity, the amount of debt as a component of total capitalization, and political, legislative, and regulatory events. Also, failure to complete our sales of the majority of our international commodities operation and our gas trading operation could result in a credit rating downgrade.

Changes in the prices of commodities and initial margin requirements impact our liquidity requirements.

As a result of the nature of our business, we are exposed to the impact of market fluctuations in the price and transportation costs of electricity, natural gas, coal, uranium, and other commodities. We seek to mitigate the effect of these fluctuations through various hedging strategies, which may require the posting of collateral by both us and our counterparties. Changes in the prices of commodities and initial margin requirements for exchange-traded contracts can affect the amount of collateral that must be posted, depending on the particular position we hold. There are certain asymmetries relating to the use of collateral that create liquidity requirements for our merchant energy business. 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. As a result, significant changes in the prices of commodities and margin requirements for exchange-traded contracts could require us to post additional collateral from time to time without our counterparties having to post collateral to us, which could adversely affect our overall liquidity and ability to finance our operations, which, in turn, could adversely affect our credit ratings.

Our merchant energy business may incur substantial costs and liabilities and be exposed to price volatility and counterparty performance risk as a result of its participation in the wholesale energy markets.

We purchase and sell power and fuel in markets exposed to significant risks, including price volatility for electricity and fuel and the credit risks of counterparties with which we enter into contracts.

We use various hedging strategies in an effort to mitigate many of these risks. However, hedging transactions do not guard against all risks and are not always effective, as they are based upon predictions about future market conditions. The inability or failure to effectively hedge assets or fuel or power positions against changes in commodity prices, interest rates, counterparty credit risk or other risk measures could significantly impair future financial results.

Exposure to electricity price volatility. We buy and sell electricity in both the wholesale bilateral markets and spot markets, which expose us to the risks of rising and falling prices in those markets, and our cash flows may vary accordingly. At any given time, the wholesale spot market price of electricity for each hour is generally determined by the cost of supplying the next unit of electricity to the market during that hour. This is highly dependent on the regional generation market. In many cases, the next unit of electricity supplied would be supplied from generating stations fueled by fossil fuels, primarily coal, natural gas and oil. Consequently, the open market wholesale price of electricity may reflect the cost of coal, natural gas or oil plus the cost to convert the fuel to electricity and an appropriate return on capital. Therefore, changes in the supply and cost of coal, natural gas and oil may impact the open market wholesale price of electricity.

A portion of our power generation facilities operates wholly or partially without long-term power purchase agreements. As a result, power from these facilities is sold on the spot market or on a short-term contractual basis, which if not fully hedged may affect the volatility of our financial results.

Exposure to fuel cost volatility. Currently, our power generation facilities purchase a portion of their fuel through short-term contracts or on the spot market. Fuel prices can be volatile, and the price that can be obtained for power produced from such fuel may not change at the same rate as fuel costs. As a result, fuel price changes may adversely affect our financial results.

Exposure to counterparty performance. Our merchant energy business enters into transactions with numerous third parties (commonly referred to as "counterparties"). In these arrangements, we are exposed to the credit risks of our counterparties and the risk that one or more counterparties may fail to perform under their obligations to make payments or deliver fuel or power. In addition, we 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 risks are exacerbated during periods of commodity price fluctuations. 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. Defaults by suppliers and other counterparties may adversely affect our financial results.

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Reduced liquidity in the markets in which we operate could impair our ability to appropriately manage the risks of our operations.

We are an active participant in energy markets through our competitive energy businesses. The liquidity of regional energy markets is an important factor in our ability to manage risks in these operations. Over the past several years, other market participants in the merchant energy business have ended or significantly reduced their activities as a result of several factors, including government investigations, changes in market design, and deteriorating credit quality. As a result, several regional energy markets experienced a significant decline in liquidity, which, in turn, has impacted our ability to enter into certain types of transactions to manage our risks for settlement periods beyond 18 to 24 months. Liquidity in the energy markets can be adversely affected by various factors, including price volatility and the availability of credit. As a result, future reductions in liquidity may restrict our ability to manage our risks and this could impact our financial results.

We often rely on single suppliers and at times on single customers, exposing us to significant financial risks if either should fail to perform their obligations.

We often rely on a single supplier for the provision of fuel, water, and other services required for operation of a facility, and at times, we rely on a single customer or a few customers to purchase all or a significant portion of a facility's output, in some cases under long-term agreements that provide the support for any project debt used to finance the facility. The failure of any one customer or supplier to fulfill its contractual obligations could negatively impact our financial results. Consequently, our financial performance depends on the continued performance by customers and suppliers of their obligations under these agreements.

We may not fully hedge our generation assets, customer supply activities, or other market positions against changes in commodity prices, and our hedging procedures may not work as planned.

To lower our financial exposure related to commodity price fluctuations, we routinely enter into contracts to hedge a portion of our purchase and sale commitments, weather positions, fuel requirements, inventories of natural gas, coal and other commodities, and competitive supply obligations. As part of this strategy, we routinely utilize fixed-price forward physical purchase and sales contracts, futures, financial swaps, and option contracts traded in the over-the-counter markets or on exchanges. However, we may not cover the entire exposure of our assets or positions to market price volatility, and the coverage will vary over time. Fluctuating commodity prices may negatively impact our financial results to the extent we have unhedged positions.

In addition, risk management tools and metrics such as daily value at risk, economic value at risk, stop loss limits and liquidity guidelines are based on historical price movements. If price movements significantly or persistently deviate from historical behavior, the limits may not protect us from significant losses.

Our risk management policies and procedures may not always work as planned. As a result of these and other factors, we cannot predict with precision the impact that risk management decisions may have on our financial results.

The use of derivative contracts in the normal course of business could result in financial losses that negatively impact our financial results.

We use derivative instruments such as swaps, options, futures and forwards to manage our commodity and financial market risks and to engage in trading activities. We could recognize financial losses as a result of volatility in the market values of these contracts or if a counterparty fails to perform.

In the absence of actively quoted market prices and pricing information from external sources, the valuation of these derivative instruments involves management's judgment or use of estimates. As a result, changes in the underlying assumptions or use of alternative valuation methods could affect the reported fair value of these contracts.

Additionally, the settlement of these derivative instruments could reflect a realized value that differs from our estimates of fair value.

Poor market performance will affect our benefit plan and nuclear decommissioning trust asset values, which may adversely affect our liquidity and financial results.

At December 31, 2008, our qualified pension obligations were approximately $835 million greater than the fair value of our plan assets. The Pension Protection Act requires that we fully fund our obligations by 2015. The performance of the capital markets will affect the value of the assets that are held in trust to satisfy our future obligations under our qualified pension plans. A decline in the market value of those assets or the failure of those assets to earn an adequate return may increase our funding requirements for these obligations, which may adversely affect our liquidity and financial results.

We are required to maintain funded trusts to satisfy our future obligations to decommission our nuclear power plants. A decline in the market value of those assets due to poor investment performance or other factors may increase our funding requirements for these obligations, which may have an adverse effect on our liquidity and financial results.

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The operation of power generation facilities, including nuclear facilities, involves significant risks that could adversely affect our financial results.

We own and operate a number of power generation facilities. The operation of power generation facilities involves many risks, including start-up risks, breakdown or failure of equipment, transmission lines, substations or pipelines, use of new technology, the dependence on a specific fuel source, including the transportation of fuel, or the impact of unusual or adverse weather conditions (including natural disasters such as hurricanes) or environmental compliance, as well as the risk of performance below expected or contracted levels of output or efficiency. This could result in lost revenues and/or increased expenses. Insurance, warranties, or performance guarantees may not cover any or all of the lost revenues or increased expenses, including the cost of replacement power. A portion of our generation facilities were constructed many years ago. Older generating equipment may require significant capital expenditures to keep it operating at peak efficiency. This equipment is also likely to require periodic upgrading and improvement. Breakdown or failure of one of our operating facilities may prevent the facility from performing under applicable power sales agreements which, in certain situations, could result in termination of the agreement or incurring a liability for liquidated damages.

Our generation business may incur substantial costs and liabilities due to its ownership and operation of nuclear generating facilities.

We own and operate nuclear power plants. Ownership and operation of these plants exposes us to risks in addition to those that result from owning and operating non-nuclear power generation facilities. These risks include normal operating risks for a nuclear facility and the risks of a nuclear accident.

Nuclear Operating Risks. The ownership and operation of nuclear generating facilities involve routine operating risks, including:

- mechanical or structural problems;
- inadequacy or lapses in maintenance protocols;
- impairment of reactor operation and safety systems due to human or mechanical error;
- costs of storage, handling and disposal of nuclear materials, including the availability or unavailability of a permanent repository for spent nuclear fuel;
- regulatory actions, including shut down of units because of public safety concerns, whether at our plants or other nuclear operators;
- limitations on the amounts and types of insurance coverage commercially available;
- uncertainties regarding both technological and financial aspects of decommissioning nuclear generating facilities; and
- environmental risks, including risks associated with changes in environmental legal requirements.

Nuclear Accident Risks. In the event of a nuclear accident, the cost of property damage and other expenses incurred may exceed our insurance coverage available from both private sources and an industry retrospective payment plan. In addition, in the event of an accident at one of our or another participating insured party's nuclear plants, we could be assessed retrospective insurance premiums (because all nuclear plant operators contribute to a nationwide catastrophic insurance fund). Uninsured losses or the payment of retrospective insurance premiums could each have a material adverse effect on our financial results.

Our generation investment plans may not achieve the desired financial results.

We may expand our generation capacity over the next several years through increasing the generating power of existing plants, the renovation of retired plants owned by us, and the construction or acquisition of new plants. The renovation, development, construction, and acquisition of additional generation capacity involves numerous risks. Any planned power uprates, construction, or renovation could result in cost overruns, lower than expected plant efficiency, and higher operating and other costs. With respect to the renovation of retired plants or the construction of new plants, we may incur significant sums for preliminary engineering, permitting, legal, and other expenses before it can be established whether a project is feasible, economically attractive, or capable of being financed.

If we were unable to complete the construction or renovation of a plant, we may not be able to recover our investment in the project. Furthermore, we may be unable to run any new, acquired or renovated plants as efficiently as projected, which could result in higher-than-projected operating and other costs that adversely affect our financial results.

We are subject to numerous environmental laws and regulations that require capital expenditures, increase our cost of operations and may expose us to environmental liabilities.

We are subject to extensive federal, state, and local environmental statutes, rules, and regulations relating to air quality, water quality, waste management, wildlife protection, the management of natural resources, and the protection of human health and safety that could, among other things, require additional pollution control equipment, limit the use of certain fuels, restrict the output of certain facilities, or otherwise increase costs. Significant capital expenditures, operating and other costs are associated with compliance with environmental requirements, and these expenditures and costs could become even more significant in the future as a result of regulatory changes.

For example, there is increasing likelihood that additional regulation of greenhouse gas emissions will

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occur at the federal, regional, and/or state level, which could increase our compliance and operating costs.

We are subject to liability under environmental laws for the costs of remediating environmental contamination. Remediation activities include the cleanup of current facilities and former properties, including manufactured gas plant operations and offsite waste disposal facilities. The remediation costs could be significantly higher than the liabilities recorded by us. Also, our subsidiaries are currently involved in proceedings relating to sites where hazardous substances have been released and may be subject to additional proceedings in the future.

We are subject to legal proceedings by individuals alleging injury from exposure to hazardous substances and could incur liabilities that may be material to our financial results. Additional proceedings could be filed against us in the future.

We may also be required to assume environmental liabilities in connection with future acquisitions. As a result, we may be liable for significant environmental remediation costs and other liabilities arising from the operation of acquired facilities, which may adversely affect our financial results.

We, and BGE in particular, are subject to extensive local, state and federal regulation that could affect our operations and costs.

We are subject to regulation by federal and state governmental entities, including the FERC, the NRC, the Maryland PSC and the utility commissions of other states in which we have operations. In addition, changing governmental policies and regulatory actions can have a significant impact on us. Regulations can affect, for example, allowed rates of return, requirements for plant operations, recovery of costs, limitations on dividend payments, and the regulation or re-regulation of wholesale and retail competition (including, but not limited to, retail choice and transmission costs).

BGE's distribution rates are subject to regulation by the Maryland PSC, and such rates are effective until new rates are approved. If the Maryland PSC does not approve adequate new rates, BGE might not be able to recover certain costs it incurs or earn an adequate rate of return. In addition, limited categories of costs are recovered through adjustment charges that are periodically reset to reflect current and projected costs. Inability to recover material costs not included in rates or adjustment clauses, including increases in uncollectible customer accounts that may result from higher gas and electric costs, could have an adverse effect on our, or BGE's, cash flow and financial position.

Energy legislation enacted in Maryland in June 2006 and April 2007 mandated that the Maryland PSC review Maryland's deregulated electricity market. Although the settlement agreement reached with the State of Maryland in March 2008 terminated certain studies relating to the 1999 deregulation settlement, the State of Maryland, including the Maryland legislature, and the Maryland PSC are still undertaking a review of the Maryland electric industry and market structure to consider various options for providing standard offer service to residential customers, including re-regulation. We cannot at this time predict the final outcome of this review or how such outcome may affect our, or BGE's financial results, but it could be material.

The regulatory and legislative process may restrict our ability to grow earnings in certain parts of our business, cause delays in or affect business planning and transactions and increase our, or BGE's, costs.

We operate in deregulated segments of the electric and gas industries created by federal and state restructuring initiatives. If competitive restructuring of the electric or gas industries is reversed, discontinued, restricted, or delayed, our business prospects and financial results could be materially adversely affected.

The regulatory environment applicable to the electric and natural gas industries has undergone substantial changes as a result of restructuring initiatives at both the state and federal levels. These initiatives have had a significant impact on the nature of the electric and natural gas industries and the manner in which their participants conduct their businesses. We have targeted the competitive segments of the electric and natural gas industries created by these initiatives.

Due to recent events in the energy markets, energy companies have been under increased scrutiny by state legislatures, regulatory bodies, capital markets, and credit rating agencies. This increased scrutiny could lead to substantial changes in laws and regulations affecting us, including modifications to the auction processes in competitive markets and new accounting standards that could change the way we are required to record revenues, expenses, assets, and liabilities. Recent proposals by the Maryland PSC and certain members of the Maryland legislature, relating to the structure of the electric industry in Maryland and various options for re-regulation of the industry are examples of how these laws and regulations can change. We cannot predict the future development of regulation or legislation in these markets or the ultimate effect that this changing regulatory environment will have on our business.

If competitive restructuring of the electric and natural gas markets is reversed, discontinued, restricted, or delayed, or if the recent Maryland PSC or legislative proposals are implemented in a manner adverse to us, our business prospects and financial results could be negatively impacted.

Our financial results may be harmed if transportation and transmission availability is limited or unreliable.

We have business operations throughout the United States and internationally. As a result, we depend on transportation and transmission facilities owned and operated by utilities and other energy companies to deliver the electricity, coal, and natural gas we sell to

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the wholesale and retail markets, as well as the natural gas and coal we purchase to supply some of our generating facilities. If transportation or transmission is disrupted or capacity is inadequate, our ability to sell and deliver products may be hindered. Such disruptions could also hinder our ability to provide electricity, coal, or natural gas to our customers or power plants and may materially adversely affect our financial results.

Our merchant energy business has contractual obligations to certain customers to provide full requirements service, which makes it difficult to predict and plan for load requirements and may result in increased operating costs to our business.

Our merchant energy business has contractual obligations to certain customers to supply full requirements service to such customers to satisfy all or a portion of their energy requirements. The uncertainty regarding the amount of load that our merchant energy business must be prepared to supply to customers may increase our operating costs. A significant under- or over-estimation of load requirements could result in our merchant energy business not having enough power or having too much power to cover its load obligation, in which case it would be required to buy or sell power from or to third parties at prevailing market prices. Those prices may not be favorable and thus could increase our operating costs and result in the possibility of reduced earnings or incurring losses.

Our financial results may fluctuate on a seasonal and quarterly basis or as a result of severe weather.

Our business is affected by weather conditions. Our overall operating results may fluctuate substantially on a seasonal basis, and the pattern of this fluctuation may change depending on the nature and location of any facility we acquire and the terms of any contract to which we become a party. Weather conditions directly influence the demand for electricity and natural gas and affect the price of energy commodities.

Generally, demand for electricity peaks in winter and summer and demand for gas peaks in the winter. Typically, when winters are warmer than expected and summers are cooler than expected, demand for energy is lower, resulting in less electric and gas consumption than forecasted. Depending on prevailing market prices for electricity and gas, these and other unexpected conditions may reduce our revenues and results of operations. First and third quarter financial results, in particular, are substantially dependent on weather conditions, and may make period comparisons less relevant.

Severe weather can be destructive, causing outages and/or property damage. This could require us to incur additional costs. Catastrophic weather, such as hurricanes, could impact our or our customers' operating facilities, communication systems and technology. Unfavorable weather conditions may have a material adverse effect on our financial results.

A failure in our operational systems or infrastructure, or those of third parties, may adversely affect our financial results.

Our businesses are dependent upon our operational systems to process a large amount of data and complex transactions. If any of our financial, accounting, or other data processing systems fail or have other significant shortcomings, our financial results could be adversely affected. Our financial results could also be adversely affected if an employee causes our operational systems to fail, either as a result of inadvertent error or by deliberately tampering with or manipulating our operational systems. In addition, dependence upon automated systems may further increase the risk that operational system flaws or employee tampering or manipulation of those systems will result in losses that are difficult to detect.

We may also be subject to disruptions of our operational systems arising from events that are wholly or partially beyond our control (for example, natural disasters, acts of terrorism, epidemics, computer viruses and telecommunications outages). Third party systems on which we rely could also suffer operational system failure. Any of these occurrences could disrupt one or more of our businesses, result in potential liability or reputational damage or otherwise have an adverse affect on our financial results.

Our ability to successfully identify, complete and integrate acquisitions is subject to significant risks, including the effect of increased competition.

We are likely to encounter significant competition for acquisition opportunities that may become available. In addition, we may be unable to identify attractive acquisition opportunities at favorable prices, to secure the financing necessary to undertake them, or to successfully and timely complete and integrate them.

War and threats of terrorism and catastrophic events that could result from terrorism may impact our results of operations in unpredictable ways.

We cannot predict the impact that any future terrorist attacks may have on the energy industry in general and on our business in particular. In addition, any retaliatory military strikes or sustained military campaign may affect our operations in unpredictable ways, such as changes in insurance markets and disruptions of fuel supplies and markets, particularly oil. The possibility alone that infrastructure facilities, such as electric generation, electric and gas transmission and distribution facilities would be direct targets of, or indirect casualties of, an act of terror may affect our operations.

Such activity may have an adverse effect on the United States economy in general. A lower level of economic activity might result in a decline in energy consumption, which may adversely affect our financial results or restrict our future growth. Instability in the financial markets as a result of terrorism or war may affect our stock price and our ability to raise capital.

We are subject to employee workforce factors that could affect our businesses and financial results.

We are subject to employee workforce factors, including loss or retirement of key executives or other employees, availability of qualified personnel, collective bargaining agreements with union employees, and work stoppage that could affect our financial results. In particular, our competitive energy businesses are dependent, in part, on recruiting and retaining personnel with experience in sophisticated energy transactions and the functioning of complex wholesale markets.

Our transaction with EDF is subject to closing conditions, including regulatory approvals, that, if not satisfied or waived by the appropriate party, will result in the transaction not being completed, which may result in material adverse consequences to our business and operations.

On December 17, 2008, we announced the execution of an investment agreement with EDF relating to the acquisition by EDF of a 49.99% ownership interest in our nuclear generation and operation business. The transaction is subject to closing conditions, including the receipt of consents, orders, approvals, or clearances from various federal, state and international regulatory agencies, that, if not satisfied, will prevent the transaction from being completed. In addition, if the agreement is terminated by EDF as a result of our breach of the agreement, the put arrangement between us and EDF that provides us with additional liquidity of up to $2.0 billion would also terminate.

As part of the regulatory approval process, governmental entities may impose terms and conditions that may not be acceptable to us or EDF, which may give either party the right to terminate the investment agreement. Also, governmental entities may impose terms and conditions that are unfavorable or add significant additional costs to our future operations whether the transaction is completed or not. A substantial delay in obtaining required approvals or the imposition of unfavorable terms or conditions in connection with such approvals could have a material adverse effect on our business or financial results and could also have a negative impact on our credit ratings. In addition, delays or unfavorable terms could lead us to become involved in litigation with one or more governmental entities or private litigants or may cause us or EDF to terminate the investment agreement.

If the investment agreement with EDF is terminated we will be required to issue senior notes to EDF.

If the investment agreement with EDF is terminated the Series B Preferred Stock acquired by EDF will be redeemed on the later of the date of termination of the agreement or December 31, 2009 for $1.0 billion in aggregate principal amount of 10% Senior Notes. The 10% Senior Notes to be issued upon redemption of the Series B Preferred Stock will mature on June 30, 2010. This obligation will reduce the cash available to finance our operations and other business activities and could limit our flexibility in planning for or reacting to changes in our business. The redemption of the Series B Preferred Stock could also have a negative impact on our credit ratings.

If the investment agreement with EDF is terminated and the 10% Senior Notes are issued by us upon redemption of the Series B Preferred Stock, the 10% Senior Notes will contain restrictions on the operation of our business.

The 10% Senior Notes to be issued upon redemption of our Series B Preferred Stock contain various covenants that will limit our ability to engage in specific types of transactions and in operating our business. Constellation Energy and certain of its subsidiaries will be subject to negative covenants that will be consistent with those included in Constellation Energy's credit facilities, which include limitations on indebtedness; incurring certain liens; engaging in certain fundamental changes; the sale of its assets; certain types of restricted payments; investments, loans and advances; acquisitions and transactions with affiliates; optional payments and modifications to debt instruments; and the issuance of capital stock.

The sale of non-nuclear generation plants pursuant to the put arrangement with EDF may have an adverse effect on our financial results.

We have entered into a put arrangement with EDF that, subject to regulatory approval, provides us with additional liquidity of up to $2.0 billion by allowing us to exercise an option to require EDF to acquire certain specified non-nuclear generation plants at pre-agreed prices. To the extent we exercise this option, we will no longer own the plants sold to EDF and will not be able to recognize their financial results, which may have an adverse effect on our future financial results.

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Item 2. Properties

Constellation Energy occupies approximately 970,000 square feet of leased and owned office space in North America, which includes its corporate offices in Baltimore, Maryland. We describe our electric generation properties on the next page. We also have leases for other offices and services located in the Baltimore metropolitan region, and for various real property and facilities relating to our generation projects.

BGE owns its principal headquarters building located in downtown Baltimore. BGE also leases approximately 50,000 square feet of office space. In addition, BGE owns propane air and liquefied natural gas facilities as discussed in *Item 1. Business Gas Business* section.

BGE also has rights-of-way to maintain 26-inch natural gas mains across certain Baltimore City-owned property (principally parks) which expired in 2004. BGE is in the process of renewing the rights-of-way with Baltimore City for an additional 25 years. The expiration of the rights-of-way does not affect BGE's ability to use the rights-of-way during the renewal process.

BGE has electric transmission and electric and gas distribution lines located:

- in public streets and highways pursuant to franchises, and
- on rights-of-way secured for the most part by grants from owners of the property.

We believe we have satisfactory title to our power project facilities in accordance with standards generally accepted in the energy industry, subject to exceptions, which in our opinion, would not have a material adverse effect on the use or value of the facilities.

Our merchant energy business owns several natural gas producing properties. We also lease office space in Australia, Canada, Indonesia, Japan and the United Kingdom to support our merchant energy business.

The following table describes our generating facilities:

Plant	Location	Capacity (MW)	% Owned	Capacity Owned (MW)	Primary Fuel
Calvert Cliffs Unit 1 (1)	Calvert Co., MD	873	100.0	873	Nuclear
Calvert Cliffs Unit 2 (1)	Calvert Co., MD	862	100.0	862	Nuclear
Nine Mile Point Unit 1 (1)	Scriba, NY	620	100.0	620	Nuclear
Nine Mile Point Unit 2 (1)	Scriba, NY	1,138	82.0	933	Nuclear
R.E. Ginna (1)	Ontario, NY	581	100.0	581	Nuclear
Brandon Shores	Anne Arundel Co., MD	1,286	100.0	1,286	Coal
H. A. Wagner	Anne Arundel Co., MD	995	100.0	995	Coal/Oil/Gas
C. P. Crane (2)	Baltimore Co., MD	399	100.0	399	Oil/Coal
Keystone (2)	Armstrong and Indiana Cos., PA	1,711	21.0	359(4)	Coal
Conemaugh (2)	Indiana Co., PA	1,711	10.6	181(4)	Coal
Perryman (2)	Harford Co., MD	355	100.0	355	Oil/Gas
Riverside	Baltimore Co., MD	228	100.0	228	Oil/Gas
Handsome Lake (2)	Rockland Twp, PA	268	100.0	268	Gas
Notch Cliff	Baltimore Co., MD	120	100.0	120	Gas
Westport	Baltimore City, MD	121	100.0	121	Gas
Gould Street	Baltimore City, MD	97	100.0	97	Gas
Philadelphia Road	Baltimore City, MD	64	100.0	64	Oil
Safe Harbor (2)	Safe Harbor, PA	417	66.7	278	Hydro
Grande Prairie (2)	Calgary, Alberta, Canada	85	100.00	85	Gas
West Valley (2)	West Valley, UT	200	100.00	200	Gas
Panther Creek (2)	Nesquehoning, PA	80	50.0	40	Waste Coal
Colver (2)	Colver Township, PA	104	25.0	26	Waste Coal
Sunnyside (2)	Sunnyside, UT	51	50.0	26	Waste Coal
ACE (2)	Trona, CA	102	31.1	32	Coal
Jasmin	Kern Co., CA	35	50.0	18	Coal
POSO	Kern Co., CA	35	50.0	18	Coal
Mammoth Lakes G-1	Mammoth Lakes, CA	6	50.0	3	Geothermal
Mammoth Lakes G-2	Mammoth Lakes, CA	13	50.0	7	Geothermal
Mammoth Lakes G-3	Mammoth Lakes, CA	13	50.0	7	Geothermal
Rocklin	Placer Co., CA	24	50.0	12	Biomass
Fresno	Fresno, CA	24	50.0	12	Biomass
Chinese Station	Jamestown, CA	20	45.0	9	Biomass
Malacha	Muck Valley, CA	32	50.0	16	Hydro
SEGS IV	Kramer Junction, CA	33	12.2	4	Solar
SEGS V	Kramer Junction, CA	24	4.2	1	Solar
SEGS VI	Kramer Junction, CA	34	8.8	3	Solar
Total Generating Facilities (3)		12,761		9,136	

(1)

In December 2008, we entered into an Investment Agreement with EDF under which EDF would acquire a 49.99% interest in our subsidiary that holds these nuclear generation assets. We discuss the Investment Agreement in more detail in Note 15 to Consolidated Financial Statements.

(2)

In connection with the Investment Agreement with EDF, we have the option to sell one or more of these facilities to EDF for aggregate proceeds of up to $2 billion through the earlier of December 31, 2010 or the termination of the Investment Agreement by EDF due to our breach.

(3)

The sum of the individual plant capacity megawatts may not equal the total due to the effects of rounding.

(4)

Reflects our proportionate interest in and entitlement to capacity from Keystone and Conemaugh, which include 2 MW of diesel capacity for Keystone and 1 MW of diesel capacity for Conemaugh.

In February 2008, we acquired the Hillabee Energy Center, a partially completed 774 MW gas-fired combined cycle power generation facility located in Alabama. We plan to complete the construction of this facility and expect it to be ready for commercial operation in late 2009.

As of December 31, 2008, we also have a 50% ownership interest in a waste coal processing facility located in Hazelton, Pennsylvania.

Item 3. Legal Proceedings

We discuss our legal proceedings in Note 12 to Consolidated Financial Statements.

Item 4. Submission of Matters to Vote of Security Holders

Not applicable.

Executive Officers of the Registrant

Name	Age	Present Office	Other Offices or Positions Held During Past Five Years
Mayo A. Shattuck III	54	Chairman of the Board (since July 2002), President and Chief Executive Officer (since November 2001) of Constellation Energy	Chairman of the Board of Baltimore Gas and Electric Company
Michael J. Wallace	61	Vice Chairman of Constellation Energy (since March 2008)	President and Chief Executive Officer Constellation Energy Nuclear Group, LLC and Executive Vice President Constellation Energy
Henry B. Barron	58	Executive Vice President of Constellation Energy (since April 2008); and President, Chief Executive Officer and Chief Nuclear Officer (since September 2008) of Constellation Energy Nuclear Group	Group Executive and Chief Nuclear Officer Duke Energy
Thomas F. Brady	59	Executive Vice President of Constellation Energy (since January 2004); and Chairman of the Board of Baltimore Gas and Electric Company (since April 2007)	None
James L. Connaughton	47	Executive Vice President, Corporate Affairs, Public, and Environmental Policy (since February 2009)	Chairman of the White House Council on Environmental Quality and Director of the White House Office of Environmental Policy
Paul J. Allen	57	Senior Vice President (since January 2004) and Chief Environmental Officer (since June 2007) of Constellation Energy	Vice President, Corporate Affairs Constellation Energy
Charles A. Berardesco	50	Senior Vice President (since October 2008), General Counsel (since October 2008) and Corporate Secretary (since July 2004) of Constellation Energy	Vice President and Deputy General Counsel Constellation Energy; and Associate General Counsel Constellation Energy
Brenda L. Boultwood	44	Senior Vice President and Chief Risk Officer of Constellation Energy (since January 2008)	Global Head of Strategy, Alternative Investment Services J.P. Morgan Chase & Company
Kenneth W. DeFontes, Jr.	58	Senior Vice President of Constellation Energy (since October 2004); and President and Chief Executive Officer of Baltimore Gas and Electric Company (since October 2004)	Vice President, Electric Transmission and Distribution Baltimore Gas and Electric Company
Kathleen W. Hyle	50	Senior Vice President of Constellation Energy (since September 2005); and Chief Operating Officer of Constellation Energy Resources (since November 2008)	Senior Vice President, Finance, and Chief Financial Officer Constellation Energy Nuclear Group; Chief Financial Officer UniStar Nuclear Energy; Senior Vice President, Finance Constellation Energy; and Chief Financial Officer, Constellation NewEnergy
Beth S. Perlman	48	Senior Vice President (since January 2004), Chief Administrative Officer (since June 2007) and Chief Information Officer (since April 2002) of Constellation Energy	None

Jonathan W. Thayer	37	Senior Vice President and Chief Financial Officer of Constellation Energy (since October 2008)	Vice President and Managing Director, Corporate Strategy and Development Constellation Energy; Treasurer Constellation Energy; and Senior Vice President and Chief Financial Officer Baltimore Gas and Electric Company

Officers are elected by, and hold office at the will of, the Board of Directors and do not serve a "term of office" as such. There is no arrangement or understanding between any director or officer and any other person pursuant to which the director or officer was selected.

PART II

Item 5. Market for Registrant's Common Equity, Related Shareholder Matters, Issuer Purchases of Equity Securities, and Unregistered Sales of Equity and Use of Proceeds

Stock Trading

Constellation Energy's common stock is traded under the ticker symbol CEG. It is listed on the New York and Chicago stock exchanges.

As of January 30, 2009, there were 36,697 common shareholders of record.

Dividend Policy

Constellation Energy pays dividends on its common stock after its Board of Directors declares them. There are no contractual limitations on Constellation Energy paying common stock dividends.

Dividends have been paid continuously since 1910 on the common stock of Constellation Energy, BGE, and their predecessors. Future dividends depend upon future earnings, our financial condition, and other factors.

In February 2009, we announced a quarterly dividend of $0.24 per share payable April 1, 2009 to holders of record on March 10, 2009. This is equivalent to an annual rate of $0.96 per share.

Quarterly dividends were declared on our common stock during 2008 and 2007 in the amounts set forth below.

BGE pays dividends on its common stock after its Board of Directors declares them. There are no contractual limitations on BGE paying common stock dividends unless:

- BGE elects to defer interest payments on the 6.20% Deferrable Interest Subordinated Debentures due 2043, and any deferred interest remains unpaid; or
- any dividends (and any redemption payments) due on BGE's preference stock have not been paid.

Common Stock Dividends and Price Ranges

	2008			2007		
	Dividend Declared	Price High	Price Low	Dividend Declared	Price High	Price Low
First Quarter	$0.4775	$107.97	$81.94	$0.435	$ 88.20	$68.78
Second Quarter	0.4775	94.62	78.74	0.435	95.57	82.71
Third Quarter	0.4775	85.53	13.00	0.435	98.20	76.64
Fourth Quarter	0.4775	30.17	21.70	0.435	104.29	85.81
Total	$ 1.91			$ 1.74		

Purchases of Equity Securities by the Issuer and Affiliated Purchases

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 Amount of Shares that May Yet Be Purchased Under the Plans and Programs (at month end) (2)
October 1 - October 31, 2008	3,075	$ 23.96		$ 750 million
November 1 - November 30, 2008	2,031	24.21		750 million
December 1 - December 31, 2008	725	25.01		750 million
Total	5,831	$ 24.18		

(1) *Represents shares surrendered by employees to satisfy tax withholding obligations on vested restricted stock.*

(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.*

Unregistered Sales of Equity Securities and Use of Proceeds

The sale and issuance of Constellation Energy's 8% Series A Convertible Preferred Stock to MidAmerican Energy Holdings Company was reported previously on a Current Report on Form 8-K dated September 22, 2008. The sale and issuance of Constellation Energy's 8% Series B Preferred Stock to EDF was reported previously on a Current Report on Form 8-K dated December 17, 2008. We also discuss these issuances in *Note 9 to Consolidated Financial Statements.*

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Item 6. Selected Financial Data

Constellation Energy Group, Inc. and Subsidiaries

	2008	2007	2006	2005	2004
			(In millions, except per share amounts)		
Summary of Operations					
Total Revenues	**$ 19,818.3**	$ 21,193.2	$ 19,284.9	$ 16,968.3	$ 12,127.2
Total Expenses	**20,821.9**	19,858.8	18,025.2	16,023.8	11,209.1
Gains on Sales of Assets	**25.5**		73.8		
(Loss) Income From Operations	**(978.1)**	1,334.4	1,333.5	944.5	918.1
Gains on Sales of CEP LLC equity		63.3	28.7		
Other (Expense) Income	**(52.3)**	158.6	66.1	65.5	25.5
Fixed Charges	**362.3**	305.6	328.7	310.2	326.8
(Loss) Income Before Income Taxes	**(1,392.7)**	1,250.7	1,099.6	699.8	616.8
Income Tax (Benefit) Expense	**(78.3)**	428.3	351.0	163.9	118.4
(Loss) Income from Continuing Operations and Before Cumulative Effects of Changes in Accounting Principles	**(1,314.4)**	822.4	748.6	535.9	498.4
(Loss) Income from Discontinued Operations, Net of Income Taxes		(0.9)	187.8	94.4	41.3
Cumulative Effects of Changes in Accounting Principles, Net of Income Taxes				(7.2)	
Net (Loss) Income	**$ (1,314.4)**	$ 821.5	$ 936.4	$ 623.1	$ 539.7
(Loss) Earnings Per Common Share from Continuing Operations and Before Cumulative Effects of Changes in Accounting Principles Assuming Dilution	**$ (7.34)**	$ 4.51	$ 4.12	$ 2.98	$ 2.88
(Loss) Income from Discontinued Operations		(0.01)	1.04	0.53	0.24
Cumulative Effects of Changes in Accounting Principles				(0.04)	
(Loss) Earnings Per Common Share Assuming Dilution	**$ (7.34)**	$ 4.50	$ 5.16	$ 3.47	$ 3.12
Dividends Declared Per Common Share	**$ 1.91**	$ 1.74	$ 1.51	$ 1.34	$ 1.14
Summary of Financial Condition					
Total Assets	**$ 22,284.1**	$ 21,742.3	$ 21,801.6	$ 21,473.9	$ 17,347.1
Current Portion of Long-Term Debt	**$ 2,591.5**	$ 380.6	$ 878.8	$ 491.3	$ 480.4
Capitalization					
Long-Term Debt	**$ 5,098.7**	$ 4,660.5	$ 4,222.3	$ 4,369.3	$ 4,813.2
Minority Interests	**20.1**	19.2	94.5	22.4	90.9
	190.0	190.0	190.0	190.0	190.0

Preference Stock Not Subject to Mandatory Redemption					
Common Shareholders' Equity	**3,181.4**	5,340.2	4,609.3	4,915.5	4,726.9
Total Capitalization	**$ 8,490.2**	$ 10,209.9	$ 9,116.1	$ 9,497.2	$ 9,821.0
Financial Statistics at Year End					
Ratio of Earnings to Fixed Charges	**N/A**	3.84	4.05	3.04	2.71
Book Value Per Share of Common Stock	**$ 15.98**	$ 29.93	$ 25.54	$ 27.57	$ 26.81

N/A Calculation is not applicable as a result of the net loss for 2008.

We discuss items that affect comparability between years, including acquisitions and dispositions, accounting changes and other items, in *Item 7. Management's Discussion and Analysis*.

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Baltimore Gas and Electric Company and Subsidiaries

	2008	2007	2006	2005	2004
			(In millions)		
Summary of Operations					
Total Revenues	**$ 3,703.7**	$ 3,418.5	$ 3,015.4	$ 3,009.3	$ 2,724.7
Total Expenses	**3,521.2**	3,084.2	2,646.3	2,612.8	2,353.3
Income From Operations	**182.5**	334.3	369.1	396.5	371.4
Other Income (Expense)	**29.6**	26.8	6.0	5.9	(6.4)
Fixed Charges	**139.9**	125.3	102.6	93.5	96.2
Income Before Income Taxes	**72.2**	235.8	272.5	308.9	268.8
Income Taxes	**20.7**	96.0	102.2	119.9	102.5
Net Income	**51.5**	139.8	170.3	189.0	166.3
Preference Stock Dividends	**13.2**	13.2	13.2	13.2	13.2
Earnings Applicable to Common Stock	**$ 38.3**	$ 126.6	$ 157.1	$ 175.8	$ 153.1
Summary of Financial Condition					
Total Assets	**$ 6,086.2**	$ 5,783.0	$ 5,140.7	$ 4,742.1	$ 4,662.9
Current Portion of Long-Term Debt	**$ 90.0**	$ 375.0	$ 258.3	$ 469.6	$ 165.9
Capitalization					
Long-Term Debt	**$ 2,197.7**	$ 1,862.5	$ 1,480.5	$ 1,015.1	$ 1,359.5
Minority Interest	**16.9**	16.8	16.7	18.3	18.7
Preference Stock Not Subject to Mandatory Redemption	**190.0**	190.0	190.0	190.0	190.0
Common Shareholder's Equity	**1,538.2**	1,671.7	1,651.5	1,622.5	1,566.0
Total Capitalization	**$ 3,942.8**	$ 3,741.0	$ 3,338.7	$ 2,845.9	$ 3,134.2
Financial Statistics at Year End					
Ratio of Earnings to Fixed Charges	**1.50**	2.84	3.60	4.22	3.75
Ratio of Earnings to Fixed Charges and Preferred and Preference Stock Dividends	**1.33**	2.42	2.99	3.45	3.08

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Item 7. 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 *Note 3 to Consolidated Financial Statements.*

This report is a combined report of Constellation Energy and BGE. References in this report to "we" and "our" are to Constellation Energy and its subsidiaries, collectively. References in this report to the "regulated business(es)" are to BGE. We discuss our business in more detail in *Item 1. Business* section and the risk factors affecting our business in *Item 1A. Risk Factors* section.

In this discussion and analysis, we will explain the general financial condition of 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 sources of cash for future capital expenditures,
- our net available liquidity and collateral requirements, and
- expected future expenditures for capital projects.

As you read this discussion and analysis, refer to our Consolidated Statements of Income (Loss), which present the results of our operations for 2008, 2007, and 2006. We analyze and explain the differences between periods in the specific line items of our Consolidated Statements of Income (Loss).

We have organized our discussion and analysis as follows:

- First, we discuss our strategy.
- Then, we describe the business environment in which we operate including how recent events, competition, regulation, weather, and other factors affect our business.
- Next, we discuss our critical accounting policies. These are the accounting policies that are most important to both the portrayal of our financial condition and results of operations and require management's most difficult, subjective or complex judgment.
- We highlight significant events that are important to understanding our results of operations and financial condition.
- We 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, security ratings, capital resources, capital requirements, commitments, and off-balance sheet arrangements.
- We conclude with a discussion of our exposure to various market risks.

Strategy

We are pursuing a strategy of operating nuclear and non-nuclear generation facilities, providing energy and energy-related products and services through our Customer Supply activities, and delivering electricity and gas to customers of BGE, our regulated utility located in central Maryland. Our merchant energy business focuses on short-term and long-term purchases and sales of energy, capacity, and related products to various customers, including distribution utilities, municipalities, cooperatives, and industrial, commercial, and governmental customers.

We obtain this energy from both owned and contracted supply resources. Our generation fleet is strategically located in deregulated markets and includes various fuel types, such as nuclear, coal, natural gas, oil, and renewable sources. In addition to owning generating facilities, we contract for power from other merchant providers, typically through power purchase agreements. We use both our owned generation and our contracted generation to support our wholesale and retail Customer Supply operations.

We are also in the forefront of the proposed development of new nuclear generation in the United States through our UniStar Nuclear Energy joint venture with EDF Group and related entities (EDF). In addition, in December 2008, we entered into an investment agreement with EDF to sell to EDF a 49.99% interest in our nuclear generation and operation business (Investment Agreement). EDF brings operational experience, global scale, and procurement leverage to the development of new nuclear plants in the United States and to the operation of our existing nuclear plants. This new joint venture is expected to close in the third quarter of 2009, subject to receipt of regulatory approvals.

Collectively, the integration of owned and contracted electric generation assets with origination, fuel procurement, and risk management expertise allows our merchant energy business to earn incremental margin and more effectively manage energy and commodity price risk over geographic regions and time. Our focus is on providing solutions to customers' energy needs, and our Customer Supply and Global Commodities operations add value to our owned and contracted generation assets by providing national market access, market infrastructure, real-time market intelligence, risk management and arbitrage opportunities, and transmission and transportation expertise. Generation capacity supports our Customer Supply and Global Commodities operations by providing a source of reliable power supply.

We expect BGE and our Customer Supply operation to grow through focused and disciplined expansion. At BGE, we are also focused on enhancing reliability, customer satisfaction, and customer demand response initiatives.

Customer choice, regulatory change, and energy market conditions significantly impact our business. In response, we regularly evaluate our strategies with these goals in mind: to improve our competitive position, to anticipate and adapt to the business environment and regulatory changes, and to maintain a strong balance sheet and investment-grade credit quality through the use of a financial model that applies cash flow to reduce debt.

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As a result of the significant events of 2008 as discussed in the *Business Environment* section, we are actively seeking to increase available liquidity and reduce our business risk. Over the next one to two years, we expect to be in a transition period during which we will focus on executing the following objectives that we believe will strengthen the Company:

- continuing to implement strategic initiatives to reduce collateral and liquidity needs of our merchant energy business, including selling certain assets and operations as discussed further in the *Divestitures* section in *Item 1*.
- working to close the sale to EDF of 49.99% of our nuclear generation and operation business as expeditiously as possible,
- continuing a disciplined approach to the management of collateral and liquidity, including:
  - pricing new business to reflect the full cost of capital in the current economic environment and possibly requiring deposits from new retail customers that do not meet pre-existing credit conditions,
  - balancing cash generation with earnings growth, and
  - maintaining a liquidity cushion in excess of credit-rating downgrade collateral requirements,
- focusing on Constellation Energy's core strengths of:
  - owning, developing, and operating nuclear and non-nuclear generation assets,
  - providing reliable, regulated utility service to customers,
  - leveraging our expertise in managing physical risks inherent in our Generation and Customer Supply operations, and
  - maintaining strong supply relationships with retail and wholesale customers,
- continuing to reduce the scale of and re-focus the activities of our Global Commodities and Customer Supply operations through the following actions:
  - using the Global Commodities group to support our Generation and Customer Supply operations,
  - placing less reliance on proprietary trading,
  - investing capital in areas where we are able to generate appropriate risk-adjusted returns,
- maintaining credit metrics consistent with investment grade ratings.

The execution of our strategy in the future will be affected by our ability to achieve these goals as well as by continued instability in financial and commodities markets. Execution of our goals, including the pending asset divestitures, could have a substantial effect on the nature and mix of our business activities, as well as our financial position, results of operation and cash flows.

In addition, upon closing the transaction contemplated by our Investment Agreement with EDF, we expect to deconsolidate our subsidiary that owns our nuclear generation assets. 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.

Business Environment

Various factors affect our financial results. We discuss some of these factors in more detail in *Item 1. Business Competition* section. We also discuss these various factors in the *Forward Looking Statements* and *Item 1A. Risk Factors* sections.

During the last year, two events significantly influenced our business environment: the collapse of the credit markets and the extreme volatility in the energy markets. Throughout 2008, volatility in the financial markets intensified, leading to dramatic declines in equity prices and substantially reducing liquidity in the credit markets. Most equity indices declined significantly, the cost of credit default swaps and bond spreads increased substantially, and credit markets effectively ceased to be accessible for all but the most highly rated borrowers.

Major financial institutions experienced significant financial difficulty, and widespread fears developed about the viability of any business that required access to credit markets to support liquidity needs or that required substantial access to the capital markets to function, including Constellation Energy. By mid-September 2008, despite having announced a number of actions to address our liquidity situation, we faced a sudden and immediate need to raise equity capital and take other steps to enhance our overall liquidity. As a result, on September 19, 2008, we entered into a definitive merger agreement with MidAmerican Energy Holdings Company (MidAmerican) to acquire Constellation Energy for $4.7 billion, which also provided us with an immediate $1 billion cash infusion. In December 2008, however, we terminated the merger agreement with MidAmerican and entered into an agreement to sell a 49.99% interest in our nuclear generation and operation business for $4.5 billion to EDF. Under that agreement, EDF provided us with a $1 billion cash infusion to replace the investment made by MidAmerican. We repaid MidAmerican's $1 billion plus interest in January 2009. We discuss the termination of the merger with MidAmerican and our transaction with EDF in more detail in *Note 15 to Consolidated Financial Statements*.

The volatility of the 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. We continue to actively manage our credit risk to attempt to reduce the impact of a potential counterparty default. We discuss our customer (counterparty) credit and other risks in more detail in the *Risk Management* section.

Competition

We face competition in the sale of electricity, natural gas, coal, and uranium in wholesale energy markets and to retail customers.

Various states have moved to restructure their retail electricity and gas markets. The pace of deregulation in these states varies based on historical moves to competition and responses to recent market events. While many states continue to support or expand retail competition and industry restructuring, other states that were considering deregulation

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have slowed their plans or postponed consideration. In addition, other states are reconsidering deregulation.

Specifically, legislatures in a number of states are currently considering, to varying degrees, legislation to either eliminate or expand retail choice programs. In addition, many states have initiated proceedings to reconsider the method of wholesale procurement for meeting their utilities' default/provider-of-last-resort (POLR) requirements. Both the reconsideration of retail choice and possible new methodologies for wholesale procurement could affect our Customer Supply operation's future opportunities to service commercial and industrial customers and the ability to provide wholesale products to utilities. The outcome of these efforts cannot be predicted, but they could have a material effect on our financial results.

All BGE electricity and gas customers have the option to purchase electricity and gas from alternate suppliers.

We discuss merchant competition in more detail in *Item 1. Business Competition* section.

The impacts of electric deregulation on BGE in Maryland are discussed in *Item 1. Business Baltimore Gas and Electric Company Electric Business Electric Competition* section.

Regulation Maryland

Maryland PSC

In addition to electric restructuring, which we discuss in *Item 1. Business Electric Competition section*, regulation by the Maryland Public Service Commission (Maryland PSC) significantly influences BGE's businesses. The Maryland PSC determines the rates that BGE can charge customers of its electric distribution and gas businesses. The Maryland PSC incorporates into BGE's standard offer service rates the transmission rates determined by the Federal Energy Regulatory Commission (FERC). BGE's electric rates are unbundled in customer billings to show separate components for delivery service (i.e. base rates), electric supply (commodity charge and transmission), a universal service surcharge, and certain taxes. The rates for BGE's regulated gas business continue to consist of a delivery charge (base rate) and a commodity charge.

Maryland Settlement Agreement

In March 2008, Constellation Energy, BGE, and a Constellation Energy affiliate entered into a settlement agreement with the State of Maryland, the Maryland PSC and certain State of Maryland officials to resolve pending litigation and to settle other prior legal, regulatory, and legislative issues. On April 24, 2008, the Governor of Maryland signed enabling legislation, which became effective on June 1, 2008. Pursuant to the terms of the settlement agreement:

- Each party acknowledged that the agreements adopted in 1999 relating to Maryland's electric restructuring law are final and binding and the Maryland PSC will close ongoing proceedings relating to the 1999 settlement.

- BGE provided its residential electric customers approximately $189 million in the form of a one-time $170 per customer rate credit. We recorded a reduction to "Electric revenues" on our and BGE's Consolidated Statements of Income (Loss) during the second quarter of 2008 and reduced customers' bills by the amount of the credit between September and December 2008.

- BGE customers are relieved of the potential future liability for decommissioning Constellation Energy's Calvert Cliffs Unit 1 and Unit 2, scheduled to occur no earlier than 2034 and 2036, respectively, and are no longer obligated to pay a total of $520 million, in 1993 dollars adjusted for inflation, pursuant to the 1999 Maryland PSC order regarding the deregulation of electric generation. BGE will continue to collect the $18.7 million annual nuclear decommissioning charge from all electric customers through 2016 and continue to rebate this amount to residential electric customers, as previously required by Maryland Senate Bill 1, which was enacted in June 2006.

- BGE resumed collection of the residential return portion of the administrative charge included in Standard Offer Service (SOS) rates, which had been eliminated under Senate Bill 1, on June 1, 2008 and will continue collection through May 31, 2010 without having to rebate it to all residential electric customers. This will total approximately $40 million over this period. This charge will be suspended from June 1, 2010 through December 31, 2016.

- Any electric distribution base rate case filed by BGE will not result in increased distribution rates prior to October 2009, and any increase in electric distribution revenue awarded will be capped at 5% with certain exceptions. Any subsequent electric distribution base rate case may not be filed prior to August 1, 2010. The agreement does not govern or affect our ability to recover costs associated with gas rates, federally approved transmission rates and charges, electric riders, tax increases, or increases associated with standard offer service power supply auctions.

Effective June 1, 2008, BGE implemented revised depreciation rates for regulatory and financial reporting purposes. The revised rates reduced depreciation expense by approximately $14 million in 2008 without impacting distribution rates charged to customers.

Effective June 1, 2008, Maryland laws governing investments in companies that own and operate regulated gas and electric utilities were amended to make them less restrictive with respect to certain capital stock acquisition transactions.

Constellation Energy elected two independent directors to the Board of Directors of BGE within the required six months from the execution of the settlement agreement.

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Senate Bills 1 and 400

In June 2006, Maryland Senate Bill 1 was enacted, which among other things:

- imposed rate stabilization measures that (i) capped rate increases by BGE for residential SOS service at 15% from July 1, 2006 to May 31, 2007, (ii) gave residential SOS customers the option from June 1, 2007 until December 31, 2007 of paying a full market rate or choosing a short term rate stabilization plan in order to provide a smooth transition to market rates without adversely affecting the creditworthiness of BGE, and (iii) provided for full market rates for all residential SOS service starting January 1, 2008; and
- allowed BGE to recover the costs deferred from July 1, 2006 to May 31, 2007 from its customers over a period not to exceed 10 years, on terms and conditions to be determined by the Maryland PSC, including through the issuance of rate stabilization bonds that securitize the deferred costs.

In connection with these provisions of Senate Bill 1:

- In May 2007, the Maryland PSC approved a plan to allow residential electric customers to defer the transition to full market rates from June 1, 2007 to January 1, 2008. The 4 percent of customers who chose to defer are repaying the deferred amounts without interest over a twenty-one month period which began on April 1, 2008.
- In June 2007, a subsidiary of BGE issued an aggregate principal amount of $623.2 million of rate stabilization bonds to recover costs relating to the residential rate deferral from July 1, 2006 to May 31, 2007. We discuss the rate stabilization bond issuance in more detail in *Note 9 to Consolidated Financial Statements*.

In April 2007, Maryland Senate Bill 400 was enacted, which made certain modifications to Senate Bill 1. Pursuant to Senate Bill 400, the Maryland PSC was required to initiate several studies, including studies relating to stranded costs, the costs and benefits of various options for re-regulation, and the structure of the electric industry in Maryland.

In December 2007, the Maryland PSC issued an interim report addressing the costs and benefits of various options for re-regulation and recommending actions to be taken to address an anticipated shortage of generation and transmission capacity in Maryland, which included implementation of demand response initiatives and requiring utilities to enter into long-term power purchase contracts with suppliers.

The Maryland PSC issued a final report in December 2008. In the final report, the Maryland PSC does not recommend returning the former utility generation assets to full cost of service regulation, but rather recommends incremental, forward looking re-regulation when appropriate to ensure a reliable supply of electricity or to obtain economic benefits for customers. The report also indicates that the Maryland PSC will investigate in 2009 whether, and on what terms, additional generation should be built in Maryland. In addition, the Maryland legislature continues to review the structure of the Maryland energy markets and the need for re-regulation. We cannot at this time predict the ultimate outcome of these inquiries, studies, and recommendations or their actual effect on our, or BGE's financial results, but it could be material.

We discuss the market risk of our regulated electric business in more detail in the *Risk Management* section.

Base Rates

Base rates are the rates the Maryland PSC allows BGE to charge its customers for the cost of providing them delivery service, plus a profit. BGE has both electric base rates and gas base rates.

BGE may ask the Maryland PSC to increase base rates from time to time. The Maryland PSC historically has allowed BGE to increase base rates to recover its utility plant investment and operating costs, plus a profit. Generally, rate increases improve the earnings of our regulated business because they allow us to collect more revenue. However, rate increases are normally granted based on historical data and those increases may not always keep pace with increasing costs. Other parties may petition the Maryland PSC to decrease base rates.

BGE's most recently approved return on electric distribution rate base was 9.4% (approved in 1993). BGE's most recently approved return on gas rate base was 8.49% (approved in 2005).

According to the terms of the 2008 Maryland settlement agreement, any future electric distribution base rate case filed by BGE will not result in increased distribution rates prior to October 2009, and any increase in electric distribution revenue awarded will be capped at 5% with certain exceptions. Any subsequent electric distribution base rate case may not be filed prior to August 1, 2010. The agreement does not govern or affect our ability to recover costs associated with gas rates, federally approved transmission rates and charges, electric riders, tax increases, or increases associated with standard offer service power supply auctions.

Revenue Decoupling

Beginning in 2008, the Maryland PSC approved, and BGE implemented, revenue decoupling for residential and small commercial customers to eliminate the effect of abnormal weather and usage patterns per customer on its electric distribution volumes. This means that BGE's electric distribution revenues from residential and small commercial customers reflect weather and usage that is considered normal for the month. Therefore, these revenues are affected primarily by customer growth. The Maryland PSC approved revenue decoupling for the majority of our remaining commercial and industrial customers beginning February 1, 2009. We have a similar revenue decoupling mechanism in our gas business.

Demand Response and Advanced Metering Programs

In order to implement an advanced metering pilot program and a demand response program, BGE defers costs associated with these programs as a regulatory asset and recovers these costs from customers in future periods. We discuss the advanced metering and demand response programs in more detail in *Item 1. Business Baltimore Gas and Electric Company Electric Load Management.*

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Electric Commodity and Transmission Charges

We discuss BGE electric commodity and transmission charges (standard offer service), including the impact of the enactment of Senate Bill 1 in Maryland, in the *Business Environment Regulation Maryland Senate Bills 1 and 400* section.

Gas Commodity Charge

BGE charges its gas customers separately for the natural gas they purchase. The price BGE charges for the natural gas is based on a market-based rates incentive mechanism approved by the Maryland PSC. We discuss market-based rates in more detail in the *Regulated Gas Business Gas Cost Adjustments* section and in *Note 6 to Consolidated Financial Statements.*

Federal Regulation

FERC

The FERC has jurisdiction over various aspects of our business, including electric transmission and wholesale natural gas and electricity sales. BGE transmission rates are updated annually based on a formula methodology approved by FERC. The rates also include transmission investment incentives approved by FERC in orders issued in July and November of 2007. We believe that FERC's continued commitment to fair and efficient wholesale energy markets should continue to result in improvements to competitive markets across various regions.

Since 1997, operation of BGE's transmission system has been under the authority of PJM Interconnection (PJM), the Regional Transmission Organization (RTO) for the Mid-Atlantic region, pursuant to FERC oversight. As the transmission operator, PJM administers the energy markets and conducts day-to-day operations of the bulk power system. The liability of transmission owners, including BGE, and power generators is limited to those damages caused by the gross negligence of such entities.

In addition to PJM, RTOs exist in other regions of the country such as the Midwest, New York, and New England. Similar to PJM, these RTOs also administer the energy market for their region and are responsible for operation of the transmission system and transmission system reliability. Our merchant energy business participates in these regional energy markets. These markets are continuing to develop, and revisions to market structure are subject to review and approval by FERC. We cannot predict the outcome of any reviews at this time. However, changes to the structure of these markets could have a material effect on our financial results.

FERC Initiatives

Ongoing initiatives at FERC have included a review of its methodology for the granting of market-based rate authority to sellers of electricity. FERC has established interim tests that it uses to determine the extent to which companies may have market power in certain regions. Where FERC finds that market power exists, it may require companies to implement measures to mitigate the market power in order to maintain market-based rate authority. We believe that our entities selling wholesale power continue to satisfy FERC's test for determining whether to grant a public utility market-based rate authority.

In November 2004, FERC eliminated through and out transmission rates between the Midwest Independent System Operator (MISO) and PJM and put in place Seams Elimination Charge/Cost Adjustment/Assignment (SECA) transition rates, which are paid by the transmission customers of MISO and PJM and allocated among the various transmission owners in PJM and MISO. The SECA transition rates were in effect from December 1, 2004 through March 31, 2006. FERC set for hearing the various compliance filings that established the level of the SECA rates and has indicated that the SECA rates are being recovered from the MISO and PJM transmission customers subject to refund by the MISO and PJM transmission owners.

We are a recipient of SECA payments, payer of SECA charges, and supplier to whom such charges may be shifted. Administrative hearings regarding the SECA charges concluded in May 2006, and an initial decision from the FERC administrative law judge (ALJ) was issued in August 2006. The decision of the ALJ generally found in favor of reducing the overall SECA liability. The decision, if upheld, is expected to significantly reduce the overall SECA liability at issue in this proceeding. However, the ALJ also allowed SECA charges to be shifted to upstream suppliers, subject to certain adjustments. Therefore, certain charges could be shifted to our wholesale marketing, risk management, and trading operation. This decision will be reviewed by FERC. We are unable to predict the timing or final outcome of FERC's SECA rate proceeding. However, as the amounts collected under the SECA rates are subject to refund and the ultimate outcome of the proceeding establishing SECA rates is uncertain, the result of this proceeding may have a material effect on our financial results.

Capacity Markets

In April 2006, FERC issued an initial order approving PJM's proposal to restructure its capacity market, which establishes the method by which we are paid for making generating plant capacity available to PJM. The capacity market or Reliability Pricing Model (RPM) was approved by FERC in December 2006 after settlement proceedings. FERC in June and November 2007 upheld the RPM settlement in response to requests for rehearing. An appeal of FERC's decisions on RPM was filed in January 2008 in the United States Court of Appeals for the District of Columbia Circuit. Currently, we cannot predict with certainty what effect the results of these challenges will have on our, or BGE's, financial results.

Also in January 2008 in connection with RPM, PJM filed revisions to its capacity market rules to reflect increased construction costs for new entry of generation (CONE), which was rejected by FERC in April 2008. CONE is used in determining the price paid to capacity resources that clear in the PJM capacity auction. In September 2008, FERC directed PJM to consider revisions and improvements to RPM to become effective prior to the May 2009 auction. In December 2008, PJM filed proposed tariff changes to RPM with FERC. PJM proposes significant revisions to RPM, including the determination of CONE, the participation of energy efficiency and demand resources, and market power and mitigation rules.

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We cannot predict the outcome of the FERC proceeding. However, the outcome could have a material effect on our financial results depending on the nature of the resulting changes to RPM.

In May 2008, five state public service commissions, including the Maryland PSC, consumer advocates, and others filed a complaint against PJM at the FERC, alleging that the RPM produced unreasonable prices during the period from June 1, 2008 through May 31, 2011. The complaint requests that FERC establish a refund effective date of June 1, 2008, reject the results of the 2007/08 through 2010/11 RPM capacity auction results, and significantly reduce prices for capacity beginning as of June 1, 2008 through 2011/12. We, along with other power suppliers and supplier trade groups, have filed protests to the complaint. In September 2008, FERC dismissed the complaint and in October 2008, the complainants requested a rehearing at FERC. We cannot predict the outcome of this proceeding or the amount of refunds that may be owed by or due to us, if any. However, the outcome, and any refunds that are ultimately assessed, could have a material impact on our financial results.

Three major, high-voltage transmission lines have been announced that could enhance significantly the transfer capacity of the PJM transmission system from west to east. The siting process either in the states or at FERC is uncertain, as is the likelihood that one or more of the transmission lines will be ultimately constructed. The construction of the transmission lines, which could depress both capacity and energy prices for generation located in Maryland and elsewhere in the eastern part of PJM, could have a material effect on our financial results.

Other market changes are routinely proposed and considered on an ongoing basis. Such changes will be subject to FERC's review and approval. We cannot predict the outcome of these proceedings or the possible effect on our, or BGE's, financial results at this time.

NERC Reliability Standards

In compliance with the Energy Policy Act of 2005, FERC has approved the North American Electric Reliability Corporation (NERC) as the national energy reliability organization. NERC will be responsible for the development and enforcement of mandatory reliability standards for the wholesale electric power system. We are responsible for complying with the standards in the regions in which we operate. NERC will have the ability to assess financial penalties for noncompliance, which could be material.

Weather

Merchant Energy Business

Weather conditions in the different regions of North America influence the financial results of our merchant energy business. Weather conditions can affect the supply of and demand for electricity, natural gas, and fuels. Changes in energy supply and demand may impact the price of these energy commodities in both the spot market and the forward market, which may affect our results in any given period. Typically, demand for electricity and its price are higher in the summer and the winter, when weather is more extreme. The demand for and price of natural gas and oil are higher in the winter. However, all regions of North America typically do not experience extreme weather conditions at the same time, thus we are not typically exposed to the effects of extreme weather in all parts of our business at once.

BGE

Weather affects the demand for electricity and gas for our regulated businesses. Very hot summers and very cold winters increase demand. Mild weather reduces demand. Weather affects residential sales more than commercial and industrial sales, which are mostly affected by business needs for electricity and gas. The Maryland PSC has approved revenue decoupling mechanisms which allow BGE to record monthly adjustments to the majority of our regulated electric and gas business distribution revenues to eliminate the effect of abnormal weather and usage patterns. We discuss this further in the *Regulation Maryland PSC Revenue Decoupling, Regulated Electric Business Revenue Decoupling* and *Regulated Gas Business Revenue Decoupling* sections.

Other Factors

A number of other factors significantly influence the level and volatility of prices for energy commodities and related derivative products for our merchant energy business. These factors include:

- seasonal, daily, and hourly changes in demand,
- number of market participants,
- extreme peak demands,

- available supply resources,
- transportation and transmission availability and reliability within and between regions,
- location of our generating facilities relative to the location of our load-serving obligations,
- implementation of new market rules governing operations of regional power pools,
- procedures used to maintain the integrity of the physical electricity system during extreme conditions,
- changes in the nature and extent of federal and state regulations, and
- international supply and demand.

These factors can affect energy commodity and derivative prices in different ways and to different degrees. These effects may vary throughout the country as a result of regional differences in:

- weather conditions,
- market liquidity,
- capability and reliability of the physical electricity and gas systems,
- local transportation systems, and
- the nature and extent of electricity deregulation.

Other factors also impact the demand for electricity and gas in our regulated businesses. These factors include the number of customers and usage per customer during a given period. We use these terms later in our discussions of regulated electric and gas operations. In those sections, we discuss how these and other

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factors affected electric and gas sales during the periods presented.

The number of customers in a given period is affected by new home and apartment construction and by the number of businesses in our service territory.

Usage per customer refers to all other items impacting customer sales that cannot be measured separately. These factors include the strength of the economy in our service territory. When the economy is healthy and expanding, customers tend to consume more electricity and gas. Conversely, during an economic downturn, our customers tend to consume less electricity and gas.

Environmental Matters and Legal Proceedings

We discuss details of our environmental matters in *Note 12 to Consolidated Financial Statements* and *Item 1. Business Environmental Matters* section. We discuss details of our legal proceedings in *Note 12 to Consolidated Financial Statements*. Some of this information is about costs that may be material to our financial results.

Accounting Standards Adopted and Issued

We discuss recently adopted and issued accounting standards in *Note 1 to Consolidated Financial Statements*.

Critical Accounting Policies

Our discussion and analysis of financial condition and results of operations is based on our consolidated financial statements that were prepared in accordance with accounting principles generally accepted in the United States of America. Management makes estimates and assumptions when preparing financial statements. These estimates and assumptions affect various matters, including:

- our reported amounts of revenues and expenses in our Consolidated Statements of Income (Loss),
- our reported amounts of assets and liabilities in our Consolidated Balance Sheets, and
- our disclosure of contingent assets and liabilities.

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

Management believes the following accounting policies represent critical accounting policies as defined by the Securities and Exchange Commission (SEC). The SEC defines critical accounting policies as those that are both most important to the portrayal of a company's financial condition and results of operations and require management's most difficult, subjective, or complex judgment, often as a result of the need to make estimates about the effect of matters that are inherently uncertain and may change in subsequent periods. We discuss our significant accounting policies, including those that do not require management to make difficult, subjective, or complex judgments or estimates, in *Note 1 to Consolidated Financial Statements*.

Accounting for Derivatives and Hedging Activities

We utilize a variety of derivative instruments in order to manage commodity price risk, interest rate risk, and foreign currency risk. The accounting requirements for derivatives are governed by Statement of Financial Accounting Standards (SFAS) No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended and interpreted. Because of the extensive nature of its requirements that govern both accounting treatment and documentation, as well as the complexity of the transactions within its scope, applying SFAS No. 133 requires management to exercise judgment in several areas, including the following:

- identification of derivatives,
- selection of accounting treatment for derivatives,
- valuation of derivatives, and

impact of uncertainty.

As discussed in more detail below, the exercise of management's judgment in these areas materially impacts our financial statements. While we believe we have appropriate controls in place to apply SFAS No. 133, failure to meet its requirements, even inadvertently, could require the use of a different accounting treatment for the affected transactions. In addition, interpretations of SFAS No. 133 continue to evolve, and a future change in accounting requirements also could affect our financial statements materially. We discuss derivatives and hedging activities in more detail in *Note 1* and *Note 13 to Consolidated Financial Statements*.

Identification of Derivatives

We must evaluate new and existing transactions and agreements to determine whether they are derivatives. Identifying derivatives requires us to exercise judgment in interpreting the definition of a derivative in SFAS No. 133 and applying that definition to each individual contract. If a contract is not a derivative, we cannot apply SFAS No. 133, and we generally must record the effects of the contract in our financial statements upon delivery or settlement under the accrual method of accounting. In contrast, if a contract is a derivative, we must apply SFAS No. 133, which provides for several possible accounting treatments as discussed more fully under *Accounting Treatment* below. As a result, the required accounting treatment and its impact on our financial statements can vary substantially depending upon whether a contract is a derivative or a non-derivative.

Accounting Treatment

SFAS No. 133 permits several possible accounting treatments for derivatives that meet all of the applicable requirements of that standard. SFAS No. 133 requires mark-to-market as the default accounting treatment for all derivatives unless they qualify, and we affirmatively designate them, for one of the other accounting treatments. Derivatives designated for any of the other elective accounting treatments must meet specific, restrictive criteria prescribed by SFAS No. 133, both at the time of designation and on an ongoing basis.

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The permissible accounting treatments for derivatives are:

- mark-to-market,
- cash flow hedge,
- fair value hedge, and
- accrual accounting under Normal Purchase/Normal Sale (NPNS).

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

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

We exercise judgment in determining which derivatives qualify for a particular accounting treatment under the provisions of SFAS No. 133 and its interpretations, including:

- Cash flow and fair value hedges determination that all hedge accounting requirements are satisfied, including the expectation that the derivative will be highly effective in offsetting changes in cash flows or fair value from the risk being hedged and, for cash flow hedges, the probability that the hedged forecasted transaction will occur.
- Accrual accounting under NPNS determination that the derivative will result in gross physical delivery of the underlying commodity and will not settle net.

We also exercise judgment in selecting the accounting treatment that we believe provides the most transparent presentation of the economics of the underlying transactions. Although contracts may be eligible for hedge accounting or NPNS designation, SFAS No. 133 does not require all such contracts to be designated and accounted for identically. We generally elect accrual or hedge accounting for our physical energy delivery activities (generation and customer supply) because accrual accounting more closely aligns the timing of earnings recognition, cash flows, and the underlying business activities. By contrast, we generally apply mark-to-market accounting for risk management and trading activities because changes in fair value more closely reflect the economic performance of the activity. However, we also use mark-to-market accounting for 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 so as 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.

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As a result of making these judgments, the selection of accounting treatments has a material impact on our financial position and results of operations. These impacts affect several components of our financial statements, including assets, liabilities, and accumulated other comprehensive income. Additionally, the selection of accounting treatment also affects the amount and timing of the recognition of earnings. The following table summarizes these impacts:

	Accounting Treatment			
Effect of Changes in Fair Value on:	**Mark-to-market**	**Cash Flow Hedge**	**Fair Value Hedge**	**NPNS**
Assets and liabilities	Increase or decrease in derivatives	Increase or decrease in derivatives	Increase or decrease in derivatives Decrease or increase in hedged asset or liability	No impact
Accumulated other comprehensive income (AOCI)	No impact	Increase or decrease for effective portion of hedge	No impact	No impact
Earnings prior to settlement	Increase or decrease	Increase or decrease for ineffective portion of hedge	Increase or decrease for change in derivatives Decrease or increase for change in hedged asset or liability Increase or decrease for ineffective portion	No impact
Earnings at settlement	No impact	Amounts in AOCI reclassified to earnings when hedged forecasted transaction affects earnings	Hedged margin recognized in earnings	Revenue or expense recognized in earnings when underlying physical commodity is sold or consumed

Valuation

SFAS No. 133 requires us to record mark-to-market and hedge derivatives at fair value, which represents an exit price for the asset or liability from the perspective of a market participant. An exit price is the price at which a market participant could sell an asset or transfer a liability to an unrelated party. While some of our derivatives relate to commodities or instruments for which quoted market prices are available from external sources, many other commodities and related contracts are not actively traded. Additionally, some contracts include quantities and other factors that vary over time. In these cases, we must use modeling techniques to estimate expected future market prices, contract quantities, or both in order to determine fair value.

The prices, quantities, and other factors we use to determine fair value reflect management's best estimates of inputs a market participant would consider. We record valuation adjustments to reflect uncertainties associated with estimates inherent in the determination of fair value that are not incorporated in market price information or other market-based estimates we use to determine fair value. To the extent possible, we utilize market-based data together with quantitative methods for both measuring the uncertainties for which we record valuation adjustments and determining the level of such adjustments and changes in those levels. We discuss fair value measurements in more detail in *Note 13 to Consolidated Financial Statements*.

The judgments we are required to make in order to estimate fair value have a material impact on our financial statements. These judgments affect the selection, appropriateness, and application of modeling techniques, the methods used to identify or estimate inputs to the modeling techniques, and the consistency in applying these techniques over time and across types of derivative instruments. Changes in one or more of these judgments could have a material impact on the valuation of derivatives and, as a result, could also have a material impact on our financial position or results of operations.

Impacts of Uncertainty

The accounting for derivatives and hedging activities involves significant judgment and requires the use of estimates that are inherently uncertain and may change in subsequent periods. The effect of changes in assumptions and estimates could materially impact our reported amounts of revenues and costs and could be affected by many factors including, but not limited to, the following:

- uncertainty surrounding inputs to the estimates of fair value required by SFAS No. 133 due to factors such as illiquid markets or the absence of observable market price information,
- our ability to continue to designate and qualify derivative contracts for NPNS accounting or hedge accounting under the requirements of SFAS No. 133,

potential volatility in earnings from ineffectiveness on derivatives for which we have elected hedge accounting, and

our ability to enter into new mark-to-market derivative origination transactions.

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

Long-Lived Assets

We are required to evaluate certain assets that have long lives (for example, generating property and equipment and real estate) to determine if they are impaired when certain conditions exist. SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets,* provides the accounting requirements for impairments of long-lived assets. We are required to test our long-lived assets for recoverability whenever events or changes in circumstances indicate that their carrying amount may not be recoverable. Examples of such events or changes are:

a significant decrease in the market price of a long-lived asset,

a significant adverse change in the manner an asset is being used or its physical condition,

an adverse action by a regulator or legislature or an adverse change in the business climate,

an accumulation of costs significantly in excess of the amount originally expected for the construction or acquisition of an asset,

a current-period loss combined with a history of losses or the projection of future losses, or

a change in our intent about an asset from an intent to hold to a greater than 50% likelihood that an asset will be sold or disposed of before the end of its previously estimated useful life.

For long-lived assets that can be classified as held for sale, we recognize an impairment loss to the extent their carrying amount exceeds their fair value less costs to sell. For long-lived assets that we expect to hold and use, we recognize an impairment loss only if the carrying amount of an asset is not recoverable and exceeds its fair value. The carrying amount of an asset is not recoverable if it exceeds the total undiscounted future cash flows expected to result from the use and eventual disposition of the asset. Therefore, when we believe an impairment condition may have occurred, we estimate the undiscounted future cash flows associated with the asset at the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets and liabilities. This necessarily requires us to estimate uncertain future cash flows.

In order to estimate future cash flows, we consider historical cash flows and changes in the market environment and other factors that may affect future cash flows. To the extent applicable, the assumptions we use are consistent with forecasts that we are otherwise required to make (for example, in preparing our earnings forecasts). If we are considering alternative courses of action to recover the carrying amount of a long-lived asset (such as the potential sale of an asset), we probability-weight the alternative courses of action to estimate the cash flows.

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

If we determine that the undiscounted cash flows from an asset to be held and used are less than the carrying amount of the asset, or if we have classified an asset as held for sale, we must estimate fair value to determine the amount of any impairment loss. The estimation of fair value also involves judgment. We consider quoted market prices in active markets to the extent they are available. In the absence of such information, we may consider prices of similar assets, consult with brokers, or employ other valuation techniques. Often, we will discount the estimated future cash flows associated with the asset using a single interest rate that is commensurate with the risk involved with such an investment or employ an expected present value method that probability-weights a range of possible outcomes. The use of these methods involves the same inherent uncertainty of future cash flows as discussed above with respect to undiscounted cash flows. Actual future market prices and project costs could vary from those used in our estimates, and the impact of such variations could be material.

Gas Properties

We evaluate unproved property at least annually to determine if it is impaired under SFAS No. 19, *Financial Accounting and Reporting by Oil and Gas Producing Properties*. Impairment for unproved property occurs if there are no firm plans to continue drilling, the lease is near its expiration, or historical experience necessitates a valuation allowance.

Investments

We evaluate our equity-method and cost-method investments (for example, CEP and partnerships that own power projects) to determine whether or not they are impaired. Accounting Principles Board (APB) Opinion No. 18, *The Equity Method of Accounting for Investments in Common Stock*, provides the accounting requirements for these investments. The standard for determining whether an impairment must be recorded under APB No. 18 is whether the investment has experienced a loss in value that is considered an "other than a temporary" decline in value.

The evaluation and measurement of impairments under the APB No. 18 standard involves the same uncertainties as described above for long-lived assets that we own directly and account for in accordance with SFAS No. 144. Similarly, the estimates that we make with respect to our equity and cost-method investments are subject to variation, and the impact of such variations could be material. Additionally, if the projects in which we hold these investments recognize an impairment under the provisions of SFAS No. 144, we would record our proportionate share of that impairment loss and would evaluate our investment for an other than temporary decline in value under APB No. 18.

We continuously monitor issues that potentially could impact future profitability of our equity-method investments that own geothermal, coal, hydroelectric, fuel processing projects, as well as our equity investments in our joint ventures and CEP, including environmental and legislative initiatives. We discuss certain risks and uncertainties in more detail in our *Forward Looking Statements* and *Item 1A. Risk Factors* sections. However, should future events cause these investments to become uneconomic, our investments in these projects could become impaired under the provisions of APB No. 18.

Current California statutes and regulations require load-serving entities to increase their procurement of renewable energy resources and mandate statewide reductions in greenhouse gas emissions. Given the need for electric power and the statutory and regulatory requirements increasing demand for renewable resource technologies, we believe California will continue to foster an environment that supports the use of renewable energy and continues certain subsidies that will make renewable energy projects economical. However, should California legislation and regulatory policies and federal energy policies fail to adequately support renewable energy initiatives, our equity-method investments in these types of projects could become impaired under the provisions of APB No. 18, and any losses recognized could be material.

Debt and Equity Securities

Our available for sale investments in debt and equity securities, primarily our nuclear decommissioning trust fund assets, are subject to impairment evaluations under FASB Staff Positions SFAS No. 115-1 and SFAS No. 124-1 (FSP 115-1 and 124-1), *The Meaning of Other-Than-Temporary Impairment and Its Application to Certain Investments.* FSP 115-1 and 124-1 require us to determine whether a decline in fair value of an investment below book value is other than temporary. If we determine that the decline in fair value is other than temporary, the cost basis of the investment must be written down to fair value as a new cost basis. For securities held in our nuclear decommissioning trust fund for which the market value is below book value, the decline in fair value for these securities is considered other than temporary and must be written down to fair value.

Goodwill

Goodwill is the excess of the purchase price of an acquired business over the fair value of the net assets acquired. We account for goodwill and other intangibles under the provisions of SFAS No. 142, *Goodwill and Other Intangible Assets*. We do not amortize goodwill. SFAS No. 142 requires us to evaluate goodwill for impairment at least annually or more frequently if events and circumstances indicate the business might be impaired. Goodwill is impaired if the carrying value of the business exceeds fair value. Annually, we estimate the fair value of the businesses we have acquired using techniques similar to those used to estimate future cash flows for long-lived assets as discussed on the previous page, which involves judgment. If the estimated fair value of the business is less than its carrying value, an impairment loss is required to be recognized to the extent that the carrying value of goodwill is greater than its fair value.

Asset Retirement Obligations

We incur legal obligations associated with the retirement of certain long-lived assets. SFAS No. 143, *Accounting for Asset Retirement Obligations,* provides the accounting for legal obligations associated with the retirement of long-lived assets. We incur such legal obligations as a result of environmental and other government regulations, contractual agreements, and other factors. The application of this standard requires significant judgment due to the large number and diverse nature of the assets in our various businesses and the estimation of future cash flows required to measure legal obligations associated with the retirement of specific assets. FASB Interpretation (FIN) 47, *Accounting for Conditional Asset Retirement Obligations an interpretation of FASB Statement No. 143,* clarifies that obligations that are conditional upon a future event are subject to the provisions of SFAS No. 143.

SFAS No. 143 requires the use of an expected present value methodology in measuring asset retirement obligations that involves judgment surrounding the inherent uncertainty of the probability, amount, and timing of payments to settle these obligations, and the appropriate interest rates to discount future cash flows. We use our best estimates in identifying and measuring our asset retirement obligations in accordance with SFAS No. 143.

Our nuclear decommissioning costs represent our largest asset retirement obligation. This obligation primarily results from the requirement to decommission and decontaminate our nuclear generating facilities in connection with their future retirement. We utilize site-specific decommissioning cost estimates to determine our nuclear asset retirement obligations. However, given the magnitude of the amounts involved, complicated and ever-changing technical and regulatory requirements, and the long time horizons involved, the actual obligation could vary from the assumptions used in our estimates, and the impact of such variations could be material.

In view of the significant number of assumptions underlying the decommissioning cost estimate, our estimate of the future cost of decommissioning is likely to continue to change over time. For perspective, a 10% increase or decrease in our estimate of the future cost of decommissioning our nuclear plants would produce an approximately $96 million change to our asset retirement obligation and an approximately $11 million change in our total annual amortization and accretion expenses.

Significant Events

Execution and Subsequent Termination of Merger Agreement with MidAmerican

On December 17, 2008, Constellation Energy and MidAmerican agreed to terminate the Agreement and Plan of Merger the parties had entered into on September 19, 2008. As a result, we paid MidAmerican:

- $175 million to terminate the merger, and
- $418 million in lieu of the number of shares of our common stock that were due to MidAmerican on conversion of the Series A Preferred Stock but that could not be issued due to regulatory limitations.

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Additionally, we issued 19.9 million common shares and $1 billion of 14% Senior Notes to MidAmerican in connection with the conversion of the Series A Preferred Stock.

We discuss the termination of the merger in more detail in *Note 15 to Consolidated Financial Statements*.

Investment Agreement with EDF

On December 17, 2008, Constellation Energy and EDF and related entities entered into a series of transactions under which:

- EDF will purchase from Constellation Energy a 49.99% membership interest in our nuclear generation and operation business for $4.5 billion (subject to certain adjustments) at closing, and $150 million of cash received in 2008 in addition to this purchase price.
- EDF is providing Constellation Energy with up to $2 billion of additional liquidity pursuant to a put arrangement that will allow us to require EDF to purchase certain non-nuclear generation assets.
- EDF invested $1 billion in Constellation Energy by purchasing 10,000 shares of our 8% Series B Preferred Stock. These shares will be surrendered to us when EDF purchases its membership interest in our nuclear generation and operation business, and the $1 billion will be credited against the $4.5 billion purchase price.
- EDF provided us with a $600 million interim backstop liquidity facility.
- Prior to closing, we will transfer to our nuclear generation and operation business transactions with a negative mark-to-market value not to exceed $700 million in the aggregate using a 10% discount rate. This transfer will occur in a manner that is to be determined and to be mutually acceptable to Constellation Energy and EDF.

We discuss these transactions in more detail in *Note 15 to Consolidated Financial Statements* and the Series B Preferred Stock in *Note 9 to Consolidated Financial Statements*.

Divestitures

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

In January 2009, we entered into a definitive agreement to sell a majority of our international commodities operation.

In February 2009, we entered into a definitive agreement to sell our Houston-based gas trading operation. Simultaneously, we signed a letter of intent to enter into a related transaction with an affiliate of the buyer under which that company would provide us with the gas supply needed to support our retail gas customer supply business, while reducing our credit requirements. We expect that both of these sales will close by the end of the second quarter of 2009, subject to certain regulatory approvals and other standard closing conditions.

Collectively, we expect both divestitures to return approximately $1 billion of currently posted collateral. In addition, we expect these divestitures to further reduce our downgrade collateral requirements by approximately $400 million. These reductions are based on current commodity prices, the final terms of the transactions, and the timing of collateral to be returned up to the close of the transactions, and, as a result, are subject to change.

We discuss these divestitures in more detail in *Note 3 to Consolidated Financial Statements*.

Current Market Developments

As previously discussed in the *Business Environment* section, during 2008 the financial markets experienced extreme volatility, and this volatility greatly reduced liquidity in the global credit markets. The following highlights the impacts of these developments on us:

- Several of our debt securities were downgraded by the major credit rating agencies, and we remain under review for possible downgrade by Standard & Poors Rating Group and Moody's Investors Service. We discuss our security ratings and downgrade collateral in more detail in the *Security Ratings* and *Collateral* sections.

We were required to post additional collateral with counterparties. We discuss our collateral requirements in more detail in the *Cash Flows* and *Collateral* sections.

We initiated strategic alternatives for our upstream gas properties, our international commodities operation, and our gas trading operation as well as other strategies to improve liquidity and reduce invested capital. We discuss our strategy in more detail in the *Strategy* section.

We took various other steps to reduce our exposure to the credit risk of other parties and to improve our own liquidity. We discuss our exposure to credit risk in the *Risk Management* section and we discuss our liquidity in the *Available Sources of Funding* section.

In connection with the proposed merger with MidAmerican, we received $1 billion for preferred stock issued to MidAmerican on September 22, 2008. We subsequently terminated the merger in December 2008, and we repaid the $1 billion (which had converted into 14% Senior Notes at the time of the termination of the merger) plus interest to MidAmerican in January 2009. Simultaneous with the termination of the MidAmerican merger agreement, EDF purchased $1 billion of preferred stock as part of a series of transactions contemplated by the Investment Agreement and other related agreements. We discuss the termination of the merger agreement with MidAmerican, the conversion of MidAmerican's Series A Preferred Stock as well as our transactions with EDF in *Note 15 to Consolidated Financial Statements*.

We recorded significant impairment charges in the third and fourth quarters of 2008. We discuss these impairment charges in more detail in *Note 2 to Consolidated Financial Statements*.

We incurred losses on our pension plan and nuclear decommissioning trust fund assets. We discuss our pension plan assets in more detail in the *Consolidated Nonoperating Income and Expenses* section and our nuclear decommissioning trust assets in *Item 1*.

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Commodity Prices

During 2008, the energy markets were affected by large fluctuations in commodity prices as indicated in the following table summarizing changes in spot prices during 2008:

Increases (decreases) from December 31, 2007	Six months ended June 30, 2008	Nine months ended September 30, 2008	Year ended December 31, 2008
Power	33%	(8)%	(30)%
Natural gas	44%	(5)%	(30)%
Coal	153%	58%	(1)%
Crude oil	55%	1%	(40)%

During the third and fourth quarters of 2008, prices for most commodities, including energy commodities, fell sharply after peaking early in July. The commodity price environment contributed to the following impacts on our results:

As a result of volatile commodity prices, we experienced significant mark-to-market gains during the six months ended June 30, 2008 and significant mark-to-market losses during the six months ended December 31, 2008. We discuss our mark-to-market results in the *Mark-to-Market* section.

Our total derivative assets increased $526.0 million and total derivative liabilities increased $103.6 million since December 31, 2007. We discuss our derivative assets and liabilities in more detail in the *Derivative Assets and Liabilities* section.

During 2008, we had significant fluctuations in collateral. We discuss our collateral requirements in more detail in the *Cash Flows* and *Collateral* sections.

We experienced an increase in our exposure to lower credit quality wholesale counterparties during the first half of 2008 and a decrease in our exposure to lower credit quality wholesale counterparties during the latter half of 2008 primarily due to the volatility of coal prices. We discuss our wholesale credit risk exposure in more detail in the *Wholesale Credit Risk* section.

One of our domestic coal suppliers was unable to meet production targets and filed for bankruptcy. As a result, in the quarter ended March 31, 2008, we incurred a credit loss related to this supplier. We discuss the impact of this event on our results in more detail in the *Global Commodities* section.

We experienced an increase in our allowance for uncollectible accounts receivable. We discuss our allowance for uncollectible accounts receivable in more detail in the *Allowance for Uncollectible Accounts Receivable* section.

We executed several contract settlements and amended certain other contracts, primarily in the quarter ended March 31, 2008, to reduce our exposure to supplier nonperformance risk and/or credit risk. We discuss these transactions in more detail in the *Global Commodities* section.

Workforce Reduction Costs

During the third quarter of 2008, our merchant energy business approved a restructuring of its Customer Supply operations and recognized a $2.5 million pre-tax charge.

During the fourth quarter of 2008, we approved a broader restructuring of our operations and recognized a $19.7 million pre-tax charge.

We discuss our workforce reduction costs in more detail in *Note 2 to Consolidated Financial Statements*.

Emission Allowances

During the second and third quarters of 2008, as a result of a July 11, 2008 decision by the United States Court of Appeals for the D. C. Circuit that vacated the Clean Air Interstate Rule (CAIR) and the subsequent decline in market price for our emission allowance inventory, we recorded a write-down of our emissions inventory and recognized partially offsetting gains on certain forward sales contracts. In December 2008, CAIR was reinstated and the market prices for our emission allowance inventory increased. We reversed a portion of the previous write-downs of this inventory to reflect the subsequent increase in market prices. We discuss this net charge in *Note 2 to Consolidated Financial Statements*.

Acquisitions

Hillabee Energy Center

On February 14, 2008, we acquired a partially completed gas-fired power generating facility in Alabama. We discuss this acquisition in more detail in *Note 15 to Consolidated Financial Statements.*

West Valley Power Plant

On June 1, 2008, we acquired a gas-fired peaking plant in Utah. We discuss this acquisition in more detail in *Note 15 to Consolidated Financial Statements.*

Nufcor International Limited

On June 26, 2008, we acquired a uranium marketing services company in the United Kingdom. We discuss this acquisition in more detail in *Note 15 to Consolidated Financial Statements*.

Asset Sales

Working Interests in Gas Producing Property

In 2008, we sold the following:

- a portion of our working interests in proved and unproved gas properties in Arkansas,
- our working interest in oil and natural gas producing properties to Constellation Energy Partners LLC (CEP), a related party, and
- our working interests in proved natural gas reserves in Wyoming, and our equity investment in certain entities that own interests in proved natural gas reserves and unproved properties in Texas and Montana.

We discuss these asset sales in more detail in *Note 2 to Consolidated Financial Statements*.

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Dry Bulk Vessel

On July 10, 2008, a shipping joint venture in which our merchant energy business owns a 50% ownership interest sold one of six dry bulk vessels it owns for a gain to us of approximately $29 million. We discuss this sale in more detail in *Note 2 to Consolidated Financial Statements*.

Financing Activities

In June 2008, we issued the following:

- $250.0 million of Zero Coupon Senior Notes due June 2023, and
- $450.0 million of 8.625% Series A Junior Subordinated Debentures due June 2063.

Also, in June 2008, BGE issued $400.0 million of 6.125% Notes due July 1, 2013.

In connection with the merger agreement with MidAmerican, we issued 10,000 shares of 8% Series A Convertible Preferred Stock to MidAmerican. Upon termination of the merger agreement in December 2008, this Preferred Stock converted into $1 billion of 14% Senior Notes of Constellation Energy due December 31, 2009, 19.9 million common shares (9.9% of our outstanding shares), and $418 million in cash.

In connection with the Investment Agreement with EDF, Constellation Energy issued shares of mandatorily redeemable 8% Series B Preferred Stock for $1 billion, which shares will be surrendered to us when EDF purchases its interest in our nuclear generation and operation business (and will be credited against the $4.5 billion purchase price, or, if the transaction does not close, will be redeemed at the later of the termination date or December 31, 2009 for $1 billion of 10% Senior Notes due June 30, 2010). The $1 billion proceeds from this issuance is restricted for the payment of our 14% Senior Notes held by MidAmerican. In January 2009, we repaid the 14% Senior Notes using these proceeds.

We discuss our financing activities in more detail in *Note 9 to Consolidated Financial Statements*.

As part of the Investment Agreement with EDF, EDF agreed to a put arrangement under which Constellation Energy could, at its option, sell to EDF certain non-nuclear generation assets having an aggregate value of up to $2 billion. We discuss the Investment Agreement in more detail in *Note 15 to Consolidated Financial Statements*.

In addition, EDF has also agreed to provide us with a $600 million interim backstop liquidity facility. We discuss this facility in more detail in *Note 8 to Consolidated Financial Statements*.

Maryland Settlement Agreement

In March 2008, Constellation Energy, BGE, and a Constellation Energy affiliate entered into a settlement agreement with the State of Maryland, the Maryland PSC, and certain State of Maryland officials to resolve pending litigation and to settle other prior legal, regulatory, and legislative issues. We discuss this settlement in more detail in *Note 2 to Consolidated Financial Statements*.

Results of Operations

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

As discussed in *Part I. Item 1 Business Overview* section and in the *Strategy* and *Significant Events* sections, Constellation Energy's 2008 operating results were materially impacted by a number of significant events, transactions, and resulting changes in the our strategic direction. The impact of these items has affected the comparability of our 2008 results to prior periods and will alter Constellation Energy's operating results in the future. In this section, we highlight the 2008 impact of these items.

Overview

Results

	2008	2007	2006
	(In millions, after-tax)		
Merchant energy	**$ (1,357.4)**	$ 679.2	$ 580.1
Regulated electric	**1.1**	97.9	120.2
Regulated gas	**37.2**	28.8	37.0
Other nonregulated	**4.7**	16.5	11.3
(Loss) Income from continuing operations and before cumulative effects of changes in accounting principles	**(1,314.4)**	822.4	748.6
(Loss) income from discontinued operations		(0.9)	187.8
Net (Loss) Income	**$ (1,314.4)**	$ 821.5	$ 936.4
Other Items Included in Operations (after-tax)			
Impairments and other costs	**$ (468.4)**	$ (12.2)	$
Merger termination and strategic alternatives costs:			
Merger termination costs	**(1,134.4)**		(5.7)
Strategic alternatives costs	**(70.0)**		
Maryland settlement credit	**(126.5)**		
Effective tax rate impact of Maryland settlement agreement	**16.0**		
Impairment of nuclear decommissioning trust assets	**(82.0)**		
Emission allowance write down, net	**(28.7)**		
Non-qualifying hedges	**(70.1)**	2.0	39.2
Gain on sale of gas-fired plants			47.1
Workforce reduction costs	**(13.4)**	(1.4)	(17.0)
Total Other Items	**$ (1,977.5)**	$ (11.6)	$ 63.6
Change from prior year	**$ (1,965.9)**	$ (75.2)	

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2008

Our total net loss for 2008 exceeded net income for 2007 by $2,135.9 million, or $11.84 per share, mostly because of the following:

		2008 vs. 2007
		(in millions, after-tax)
Generation gross margin	$	137
Customer Supply gross margin		(79)
Global Commodities gross margin		(97)
Sale of upstream gas assets		16
2007 sale of CEP LLC equity		(39)
Hedge ineffectiveness		(26)
Credit loss coal supplier bankruptcy		(33)
Merchant operating expenses excluding bad debt expense, primarily labor and benefit costs		57
Merchant bad debt expense		(19)
Merchant interest expense		(63)
Synthetic fuel facilities		(9)
Other nonregulated businesses		(12)
Total change in Other Items included in operations per *Overview Results* table		(1,966)
Interest and investment income		(35)
All other changes		32
Total Change	$	(2,136)

2007

Our total net income for 2007 decreased $114.9 million, or $0.66 per share, compared to 2006 mostly because of the following:

		2007 vs. 2006
		(in millions, after-tax)
Generation gross margin	$	98
Customer supply and global commodities earnings, primarily higher gross margin, partially offset by higher operating expenses		23
Absence of 2006 gain on sale High Desert		(189)
Gain on sales of CEP equity		21
Synthetic fuel facilities		(34)
Regulated operations, primarily impact of Senate Bill 1 and higher operations and maintenance expenses		(31)
Total change in Other Items included in operations per *Overview Results* table		(75)
Interest and investment income		70
All other changes		2
Total Change	$	(115)

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.

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.

We are continuing to assess the ongoing capital requirements of the merchant energy business, including evaluating the proper size of our Customer Supply and Global Commodities operations, and we are pursuing various strategic initiatives for our Global Commodities operation. As previously discussed, we have made substantial changes in our strategy. We discuss our strategy in more detail in the *Strategy* section.

While we have entered into definitive agreements in 2009 for the sale of a majority of our international commodities operation and our gas trading operation, the execution of our strategy in the future will be affected by continued instability in 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 *Note 3 to Consolidated Financial Statements.*

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 to Consolidated Financial Statements*.

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 additional returns. We manage these activities through daily value at risk and stop loss limits and liquidity guidelines, and they can have a material impact on our financial results. We discuss the impact of our trading activities and value at risk in more detail in the *Mark-to-Market* and *Risk Management* sections.

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Results

	2008	2007	2006
		(In millions)	
Revenues	**$ 16,772.8**	$ 18,744.5	$ 17,166.2
Fuel and purchased energy expenses	**(13,791.4)**	(15,501.8)	(14,256.3)
Operating expenses	**(1,729.7)**	(1,791.8)	(1,549.4)
Impairment losses and other costs	**(741.8)**	(20.2)	
Workforce reduction costs	**(15.4)**	(2.3)	(28.2)
Merger termination and strategic alternatives costs	**(1,204.4)**		(13.1)
Depreciation, depletion, and amortization	**(287.1)**	(269.9)	(258.7)
Accretion of asset retirement obligations	**(68.4)**	(68.3)	(67.6)
Taxes other than income taxes	**(124.3)**	(110.2)	(120.0)
Gains on sales of upstream gas assets	**25.5**		
Gain on sale of gas-fired plants			73.8
(Loss) Income from Operations	**$ (1,164.2)**	$ 980.0	$ 946.7
(Loss) Income from continuing operations and before cumulative effects of changes in accounting principles (after-tax)	**$ (1,357.4)**	$ 679.2	$ 580.1
(Loss) Income from discontinued operations (after-tax)		(0.9)	186.9
Net (Loss) Income	**$ (1,357.4)**	$ 678.3	$ 767.0
Other Items Included in Operations (after-tax)			
Impairments and other costs	**$ (468.4)**	$ (12.2)	$
Merger termination and strategic alternatives costs	**(1,204.4)**		(4.3)
Impairment of nuclear decommissioning trust assets	**(82.0)**		
Emission allowance write-down, net	**(28.7)**		
Gain on sale of gas-fired plants			47.1
Non-qualifying hedges	**(70.1)**	2.0	39.2
Workforce reduction costs	**(9.3)**	(1.4)	(17.0)
Total Other Items	**$ (1,862.9)**	$ (11.6)	$ 65.0

Above amounts include intercompany transactions eliminated in our Consolidated Financial Statements. Note 3 provides a reconciliation of operating results by segment to our Consolidated Financial Statements.

Revenues and Fuel and Purchased Energy Expenses

Our merchant energy business manages the revenues we realize from the sale of energy 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. 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.

In the third quarter of 2007, we changed the management of the wholesale procurement function for retail gas activities from our Customer Supply operation to our Global Commodities operation. In connection with this change, we began to prospectively account for the underlying retail gas contracts as derivative contracts subject to mark-to-market accounting, under which changes in fair value are recorded in revenues as they occur. This activity was previously accounted for on a gross basis and recorded in accrual revenues and fuel and purchased energy expenses. The change to market-to-market accounting for this activity reduced both our accrual revenues and fuel and purchased energy expenses in 2008 and 2007. However, the change had a minimal impact on gross margin.

We discuss our merchant energy revenues, fuel and purchased energy expenses, and gross margin below.

Revenues

Our merchant energy revenues decreased $1,971.7 million in 2008 compared to 2007 and increased $1,578.3 million in 2007 compared to 2006 primarily due to the following:

	2008 vs. 2007	2007 vs. 2006
	(In millions)	
Change in Global Commodities mark-to-market revenues due to (unfavorable) favorable changes in power and gas prices	**$ (403)**	$ 71
Change in contract prices and volume of business primarily related to our coal and international freight operation	**(281)**	716
Realization of higher contract prices on wholesale and retail load at our Global Commodities and Customer Supply operations	**658**	1,152
All other (substantially all due to change in gas procurement activities)	**(1,946)**	(361)
Total (decrease) increase in merchant revenues	**$ (1,972)**	$ 1,578

Fuel and Purchased Energy Expenses

Our merchant energy fuel and purchased energy expenses decreased $1,710.4 million in 2008 compared to 2007 and increased $1,245.5 million in 2007 compared to 2006 primarily due to the following:

	2008 vs. 2007	2007 vs. 2006
	(In millions)	
Change in Global Commodities mark-to-market expenses related to international coal purchase contracts	**$ (106)**	$ 18
Change in contract prices and volume of business primarily related to our coal and freight operation	**(238)**	733
Realization of higher contract prices on wholesale and retail purchases at our Global Commodities and Customer Supply operations	**710**	813
(Decrease) increase in synfuels expenses due to expiration of tax credits in 2007	**(141)**	36
All other (substantially all due to change in gas procurement activities)	**(1,935)**	(354)
Total decrease in merchant energy revenues	**$ (1,710)**	$ 1,246

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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 prior 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 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.

Global Commodities our marketing, risk management, and trading operation that manages contractually owned physical assets, including generation facilities, natural gas properties, international coal sourcing and freight assets, provides risk management services, uranium marketing 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:

	2008		2007		2006	
	(Dollar amounts in millions)					
		% of Total		**% of Total**		**% of Total**
Gross margin:						
Generation	$1,956	66%	$1,700	53%	$1,490	51%
Customer Supply	765	25	889	27	764	26
Global Commodities	260	9	654	20	656	23
Total	$2,981	100%	$3,243	100%	$2,910	100%

In December 2006, we completed the sale of these gas-fired plants:

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

This sale impacted our results of operation and cash flows for 2006 when compared to 2007. We discuss the sale of these gas-fired generating facilities in *Note 2 to Consolidated Financial Statements.*

Generation

The $256 million increase in Generation gross margin in 2008 compared to 2007 is primarily due to the following:

- $245 million increase from higher energy prices for the output of our generating assets in the PJM and New York regions based on prices established at the end of 2007 (see Global Commodities discussion below for impact of price changes during 2008), and
- $11 million of higher earnings for lower planned and unplanned outages at our nuclear and fossil plants.

The $210 million increase in generation gross margin in 2007 compared to 2006 is primarily due to approximately $290 million increase from higher energy prices for the output of our generating assets in the PJM and New York regions based on prices established at the end of 2006 (see Global Commodities discussion below for impact of price changes during 2007). This increase was partially offset by lower gross margin due to the absence of approximately $80 million of gross margin associated with the gas plants that were sold in December 2006.

Customer Supply

The $124 million decrease in Customer Supply gross margin in 2008 compared to 2007 is primarily due to the following:

- $112 million of lower gross margin related to unfavorable price movements and lower volumes in our retail power operation,

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$49 million of lower gross margin related to lower realization of contracts executed in prior periods and lower new business originated and realized during the year at our wholesale power operation, and

$27 million of lower mark-to-market results in our retail gas operation. We discuss this in more detail in the *Mark-to-Market* section.

These decreases were partially offset by approximately $64 million of higher gross margin related to our retail gas operation primarily due to the acquisition of Cornerstone Energy on July 1, 2007.

The $125 million increase in Customer Supply gross margin in 2007 compared to 2006 is primarily due to approximately $182 million of higher realization of contracts executed in prior periods and new contracts executed, including the portfolio of contracts acquired in the southeast United States, primarily for our wholesale and retail power operations. These increases were partially offset by the following:

$30 million of lower gross margin related to lower prices, partially offset by higher volumes related to our retail gas operation, and

$27 million of lower mark-to-market results in our retail gas operation. We discuss this in more detail in the *Mark-to-Market* section.

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. It also deploys risk capital in traded energy markets.

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 and freight logistics).

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.

As previously discussed in the *Significant Events* section, the energy markets were affected by substantial volatility in commodity prices during 2008. These market impacts are reflected in the $394 million decrease in gross margin from our Global Commodities operation during 2008 compared to the same period of 2007 primarily due to $698 million of lower gross margin in our portfolio management and trading activities, partially offset by $208 million of higher gross margin in our structured products portfolio and $96 million of higher gross margin in our energy investments portfolio. We discuss these changes below.

The $698 million of lower gross margin related to our portfolio management and trading operation are due to the following:

$282 million of lower gross margin related to our portfolio of contracts subject to mark-to-market accounting. We discuss these transactions in more detail in the *Mark-to-Market* section.

$206 million of lower gross margin related to portfolio management of positions arising from our Generation, Customer Supply, structured products, and energy investments activities due to the impact of unfavorable changes in prices of power, natural gas, and coal on those positions (see the description of the effects of pricing on Generation and Customer Supply activities,

$70 million related to write-downs of our emission allowance inventory to reflect current market price decreases. We discuss this in more detail in *Note 2 to Consolidated Financial Statements*.

$55 million related 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.

$43 million related to losses recognized on hedges due to ineffectiveness and certain cash-flow hedges that no longer qualified for hedge accounting.

On October 31, 2008, we discontinued the use of hedge accounting for derivative contracts that previously were accounted for as cash-flow hedges within the international commodities operation. From that date, subsequent changes in fair value of those derivative contracts have been recorded in earnings. At December 31, 2008, we concluded that the combination of the decline in value associated with the previously hedged transactions together with the related balances remaining in accumulated other comprehensive income, would lead to the recognition of a net loss in one or more future periods. As such, we recognized a loss of $42 million during the fourth quarter of 2008.

These decreases in gross margin related to our portfolio management and trading activities are partially offset by higher gross margin of:

$208 million from gains in our structured products portfolio, consisting of approximately $135 million as a result of the termination and sale of in-the-money energy purchase contracts, coal supply contracts, and freight contracts to eliminate or reduce operation and performance risk with certain counterparties, and approximately $73 million related to higher realization of contracts executed in prior periods, and

$96 million in our energy investments operation primarily due to approximately $67 million related to higher realization of contracts executed in prior periods and a $29 million gain on sale of a dry bulk vessel in our shipping joint venture. We discuss this sale in more detail in *Note 2 to Consolidated Financial Statements*.

The $2 million decrease in gross margin from our Global Commodities operation in 2007 as compared to the same period in 2006 is primarily due to lower gross margin of $43 million in our portfolio management and trading operation and $34 million of lower gross margin in our structured products portfolio, partially offset by higher gross margin of $75 million related to our energy investments portfolio. We discuss these changes below.

The decrease in gross margin of $43 million as a result of portfolio management and trading is primarily related to the following:

- $139 million related to losses recognized on hedges due to ineffectiveness and certain cash-flow hedges that no longer qualified for hedge accounting during the year,
- $72 million of lower gross margin related to portfolio management of positions arising from our Generation, Customer Supply, and structured products activities due to the impact of unfavorable changes in prices of power, natural gas, and coal on those positions (see the description of the effects of pricing on Generation and Customer Supply activities in the preceding sections).

These decreases were partially offset by $168 million of higher gross margin related to our portfolio of contracts subject to mark-to-market accounting, including higher earnings of $28 million related to increased origination gains primarily associated with nonderivative contracts that were amended to reduce counterparty nonperformance risk, resulting in the contracts becoming derivatives for which mark-to-market accounting is required. We discuss these transactions in more detail in the *Mark-to-Market* section,

The decrease in gross margin of $34 million for the structured products portfolio is primarily related to fewer contract terminations and sales during 2007 as compared to 2006.

These decreases were partially offset by an increase in gross margin of $75 million from the energy investments portfolio, primarily related to the following:

- $44 million of earnings related to our natural gas properties, including the acquisition of working interests in gas producing fields in Oklahoma. We discuss this in more detail in the *Note 15 to Consolidated Financial Statements*, and
- $31 million due to higher realization from contracts executed in prior periods and higher new business originated and realized during the period.

Mark-to-Market

Mark-to-market results include net gains and losses from origination, trading, and risk management activities for which we use the mark-to-market method of accounting. We discuss these activities and the mark-to-market method of accounting in more detail in the *Critical Accounting Policies* section and in *Note 1 to Consolidated Financial Statements*.

As a result of the nature of our operations and the use of mark-to-market accounting for certain activities, mark-to-market earnings will fluctuate. We cannot predict these fluctuations, but the impact on our earnings could be material. We discuss our market risk in more detail in the *Risk Management* section. 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 currently assessing the ongoing capital requirements of the merchant energy business and are pursuing 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 changes in market prices as a result of our gas transportation and storage activities, while in general the underlying physical transactions related to our gas transportation and storage and freight activities are accounted for on an accrual basis. We use other non-trading derivative transactions subject to mark-to-market accounting to manage our exposure to changes in market prices related to our other activities that 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.

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Mark-to-market results were as follows:

	2008	2007	2006
		(In millions)	
Unrealized mark-to-market results			
Origination gains	**$ 73.8**	$ 41.9	$ 13.5
Risk management and trading mark-to-market			
Unrealized changes in fair value	**159.8**	500.8	387.4
Changes in valuation techniques			
Reclassification of settled contracts to realized	**48.2**	(369.3)	(372.1)
Total risk management and trading mark-to-market	**208.0**	131.5	15.3
Total unrealized mark-to-market*	**281.8**	173.4	28.8
Realized mark-to-market	**(48.2)**	369.3	372.1
Total mark-to-market results	**$ 233.6**	$ 542.7	$ 400.9

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

Total mark-to-market results decreased $309.1 million during the year ended December 31, 2008 compared to the same period of 2007 primarily due to unrealized changes in fair value. The period-to-period variance in unrealized changes in fair value was primarily due to lower gains from unrealized changes in fair value of $341.0 million from risk management and trading, partially offset by an increase in origination gains of $31.9 million. We discuss the increase in origination gains below.

The net decrease in risk management and trading gains of $341.0 million was primarily due to:

- $619 million of increased losses primarily related to power and transmission trading activities in the northeast, PJM, and ERCOT regions due to unfavorable price movements, execution of transactions to reduce our risk position consistent with changes in our strategy, and execution of those transactions in less liquid market conditions,
- lower gains of $29 million from our emissions trading activities due primarily to unfavorable price movements, and
- $104 million of increased losses related to unfavorable price movements on certain economic hedges of accrual transactions, primarily related to gas transportation and storage and freight activities that do not qualify for or are not designated as cash-flow hedges.

The risk management and trading results were partially offset by:

- $356 million of gains primarily as a result of favorable price movements relating to economic hedges which substantially increased in value as coal prices decreased in the fourth quarter of 2008. These positions were previously accounted for as cash-flow hedges and were de-designated due to the announced sale of our international commodities operation, and
- $55 million of gains primarily related to our wholesale and retail gas businesses due to favorable price movements on our sales of wholesale and retail natural gas.

Total mark-to-market results increased $141.8 million during the year ended December 31, 2007 compared to the same period of 2006 primarily due to:

- higher gains from unrealized changes in fair value of $113.4 million, and
- an increase in origination gains of $28.4 million.

We discuss the increase in origination gains below.

The $113.4 million in higher gains from unrealized changes in fair value was primarily driven by:

- $73 million of gains related to our emissions trading activities due primarily to favorable price movements,
- $69 million of gains related to our coal and freight portfolio management and trading activities primarily due to favorable price movements, and
- $13 million of gains related to power, transmission, and natural gas in the northeast, PJM, and ERCOT regions due to favorable price movements and increased volume.

These gains were partially offset by $42 million of losses related to unfavorable price movements on certain economic hedges of accrual transactions that do not qualify for or are not designated as cash-flow hedges, primarily relating to gas transportation and storage and freight activities.

Origination gains arose primarily from:

- 6 transactions in 2008, which are discussed in more detail below, and
- 1 transaction in 2007, which is discussed in more detail below.

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

During 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 are derivatives subject to mark-to-market accounting under SFAS No. 133. The change in accounting for these contracts from nonderivative to derivative resulted in substantially all of the origination gains for 2008 presented in the table above.

During 2007, our Global Commodities operation amended certain nonderivative power sales contracts such that the new contracts became derivatives subject to mark-to-market accounting under SFAS No. 133. Simultaneous with the amending of the nonderivative contracts, we executed at current market prices several new offsetting derivative power purchase contracts subject to mark-to-market accounting. The combination of these transactions resulted in substantially all of the origination gains presented for 2007 in the preceding table,

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as well as mitigated our risk exposure under the amended contracts.

The origination gains in 2007 from these transactions was partially offset by approximately $12 million of losses in our accrual portfolio due to the reclassification of losses related to cash-flow hedges previously established for the amended nonderivative contracts from "Accumulated other comprehensive loss" into earnings. In the absence of these transactions, the economic value represented by the origination gains and the losses associated with cash-flow hedges would have been recognized over the remaining term of the contracts, which extended through the first quarter of 2009.

Derivative Assets and Liabilities

Derivative assets and liabilities consisted of the following:

At December 31,	**2008**	2007
	(In millions)	
Current assets	**$ 1,465.0**	$ 760.6
Noncurrent assets	**851.8**	1,030.2
Total assets	**2,316.8**	1,790.8
Current liabilities	**1,241.8**	1,134.3
Noncurrent liabilities	**1,115.0**	1,118.9
Total liabilities	**2,356.8**	2,253.2
Net derivative position	**$ (40.0)**	$ (462.4)
Composition of net derivative exposure:		
Hedges	**$ (1,837.6)**	$ (937.6)
Mark-to-market	**1,485.9**	673.0
Net cash collateral included in derivative balances	**311.7**	(197.8)
Net derivative position	**$ (40.0)**	$ (462.4)

As discussed in our *Critical Accounting Policies* section, 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 netting, which is discussed in more detail in *Note 1 to Consolidated Financial Statements*. 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. However, we present our gross derivatives as required by SFAS No. 157, *Fair Value Measurements*, in *Note 13 to Consolidated Financial Statements.*

The increase of $900.0 million in our net derivative liability subject to hedge accounting since December 31, 2007 was due primarily to $1,232 million of unrealized losses associated with existing hedge positions due to unfavorable price changes. These losses were partially offset by $332 million related to the settlement of out-of-the-money cash-flow hedges during 2008. To the extent that these hedges are effective, these unrealized losses will be offset by unrealized gains on the related hedged transactions that will be realized when those transactions affect earnings. We record any hedge ineffectiveness in earnings as it occurs.

The following are the primary sources of the change in our net derivative asset subject to mark-to-market accounting during 2008 and 2007:

	2008	2007
	(In millions)	
Fair value beginning of year	**$ 673.0**	$ 454.1
Changes in fair value recorded in earnings		

Origination gains	**$ 73.8**	$ 41.9
Unrealized changes in fair value	**159.8**	500.8
Changes in valuation techniques		
Reclassification of settled contracts to realized	**48.2**	(369.3)
Total changes in fair value	**281.8**	173.4
Changes in value of exchange-listed futures and options	**571.3**	18.6
Net change in premiums on options	**19.2**	(19.0)
Contracts acquired		83.8
Other changes in fair value	**(59.4)**	(37.9)
Fair value at end of year	**$ 1,485.9**	$ 673.0

Changes in our net derivative asset subject to mark-to-market accounting that affected earnings were as follows:

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

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

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

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

The net mark-to-market 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 nonregulated 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.

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

Other changes in fair value include transfers of derivative assets and liabilities between accounting methods resulting from the designation and de-designation of cash-flow hedges.

Effective January 1, 2008, we adopted SFAS No. 157 for our financial assets and liabilities, which defines fair value, establishes a framework for measuring fair value, and requires certain disclosures about fair value measurements. Fair value is the price that a market participant 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).

Consistent with the exit price concept, upon adoption we reduced our derivative liabilities to reflect our own credit risk. As a result, during the first quarter of 2008 we recorded a pre-tax reduction in "Accumulated other comprehensive loss" totaling $10 million for the portion related to cash-flow hedges and a pre-tax gain in earnings totaling $3 million for the remainder of our derivative liabilities. All other impacts of adoption were immaterial. We discuss SFAS No. 157 and how we determine fair value in more detail in *Note 13 to Consolidated Financial Statements*.

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 established by SFAS No. 157 are as follows as of December 31, 2008:

	Settlement Term							
	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**Thereafter**	**Fair Value**
				(In millions)				
Level 1	$ (19.9)	$	$	$	$	$	$	$ (19.9)
Level 2	520.0	(45.8)	196.8	99.9	(16.1)	(0.4)	(0.6)	753.8
Level 3	312.7	343.9	147.4	(38.8)	(11.2)	2.9	(4.9)	752.0
Total net derivative asset (liability) subject to mark-to-market accounting	$812.8	$298.1	$344.2	$ 61.1	$(27.3)	$ 2.5	$ (5.5)	$1,485.9

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

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

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

In order to realize the entire value of a long-term contract in a single transaction, we would need to sell or assign the entire contract. If we were to sell or assign any of our long-term contracts in their entirety, we may not realize the entire value reflected in the preceding table. However, based upon the nature of our 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 $62.1 million during 2008 compared to 2007 mostly due to lower performance-based labor and benefit costs at our merchant energy business of $129.2 million, partially offset by higher non-labor operating expenses of $67.1 million, which included approximately $32 million of higher bad debt expense.

Our merchant energy business operating expenses increased $242.4 million during 2007 compared to 2006 mostly due to an increase at our Global Commodities and Customer Supply operations totaling $218.4 million, primarily related to the continued growth of this operation and higher compensation and benefit costs.

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Impairments and Other Costs

Our impairments and other costs are discussed in more detail in *Note 2 to Consolidated Financial Statements*.

Workforce Reduction Costs

Our merchant energy business recognized expenses associated with our workforce reduction efforts as discussed in more detail in *Note 2 to Consolidated Financial Statements*.

Merger Termination and Strategic Alternatives Costs

We discuss costs related to the terminated merger with MidAmerican, the conversion of the Series A Preferred Stock, the Investment Agreement with EDF and our pursuit of other strategic alternatives in *Note 2 to Consolidated Financial Statements*.

Depreciation, Depletion and Amortization Expense

Merchant energy depreciation, depletion, and amortization expenses increased $17.2 million in 2008 compared to 2007 mostly due to increased depletion expenses related to our upstream natural gas operations as a result of increased drilling and production, partially offset by the cessation of operations at our synfuel facilities in December 2007.

Merchant energy depreciation, depletion, and amortization expenses increased $11.2 million in 2007 compared to 2006 mostly due to:

- $30.9 million related to our upstream natural gas operations, primarily due to acquisitions made in 2007, and
- $6.2 million primarily related to additions to our nuclear facilities, including the impact of the uprate at our Ginna facility in 2006.

These increases were partially offset by $29.0 million primarily related to the absence of depreciation associated with the gas plants that were sold in December 2006.

Taxes Other Than Income Taxes

Taxes other than income taxes increased $14.1 million in 2008 compared to 2007, primarily due to $9.8 million in higher property and franchise taxes at our Generation operation, $2.9 million of higher gross receipts taxes at our retail customer supply operation, and $1.4 million of higher production taxes related to our upstream gas producing properties.

Taxes other than income taxes decreased $9.8 million in 2007 compared to 2006, primarily due to $5.8 million lower gross receipts tax at our retail customer supply operation and a $4.2 million decrease due to the sale of our gas-fired plants.

Gains on Sale of Assets

During 2008, we recognized net gains of $25.5 million, including a $14.3 million gain, net of the minority interest gain of $0.7 million, related to the sale of our working interests in oil and natural gas producing wells in Oklahoma to Constellation Energy Partners that was completed in the first quarter of 2008.

We discuss our gains on sale of assets in more detail in *Note 2 to Consolidated Financial Statements.*

Regulated Electric Business

Our regulated electric business is discussed in detail in *Item 1. Business Electric Business* section.

Results

	2008	2007	2006
		(In millions)	
Revenues	**$ 2,679.7**	$ 2,455.7	$ 2,115.9
Electricity purchased for resale expenses	**(1,880.1)**	(1,500.4)	(1,167.8)
Operations and maintenance expenses	**(380.5)**	(376.1)	(351.3)
Workforce reduction costs	**(4.6)**		
Merger termination and strategic alternatives costs *			(3.3)
Depreciation and amortization	**(184.2)**	(187.4)	(181.5)
Taxes other than income taxes	**(139.1)**	(140.2)	(134.9)
Income from Operations	**$ 91.2**	$ 251.6	$ 277.1
Net Income	**$ 1.1**	$ 97.9	$ 120.2
Other Items Included in Operations (after-tax):			
Maryland settlement credit	**$ (126.5)**	$	$
Effective tax rate impact of Maryland settlement agreement	**16.0**		
Workforce reduction costs	**(2.8)**		
Merger termination and strategic alternatives costs *			(0.8)
Total Other Items	**$ (113.3)**	$	$ (0.8)

Above amounts include intercompany transactions eliminated in our Consolidated Financial Statements. Note 3 provides a reconciliation of operating results by segment to our Consolidated Financial Statements.

*

Costs allocated to the regulated electric business during 2008 prior to the transaction with EDF have been allocated to the merchant energy segment.

Net income from the regulated electric business decreased $96.8 million in 2008 compared to 2007, primarily due to the impact of the Maryland settlement credit of $126.5 million after-tax, partially offset by the impact on the effective tax rate of the Maryland settlement credit of $16.0 million and reduced depreciation and amortization expense of $2.0 million after-tax.

Net income from the regulated electric business decreased $22.3 million in 2007 compared to 2006, primarily due to the following:

increased operations and maintenance expenses of $15.0 million after-tax mostly due to higher labor and benefits costs,

increased depreciation and amortization of $3.6 million after-tax, and

increased taxes other than income taxes of $3.2 million after-tax.

The decrease was partially offset by an increase in revenues less electricity purchased for resale expenses of $4.4 million after-tax, which includes the impact of Senate Bill 1 credits.

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Electric Revenues

The changes in electric revenues in 2008 and 2007 compared to the respective prior year were caused by:

	2008	2007
	(In millions)	
Distribution volumes	**$ (15.0)**	$ 19.5
Maryland settlement credit	**(189.1)**	
Revenue decoupling	**12.5**	
Standard offer service	**79.4**	267.8
Rate stabilization credits	**287.3**	34.6
Rate stabilization recovery	**43.1**	36.1
Financing credits	**(9.1)**	(7.5)
Senate Bill 1 credits	**3.3**	(29.7)
Total change in electric revenues from electric system sales	**212.4**	320.8
Other	**11.6**	19.0
Total change in electric revenues	**$ 224.0**	$ 339.8

Distribution Volumes

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

The percentage changes in our electric system distribution volumes, by type of customer, in 2008 and 2007 compared to the respective prior year were:

	2008	2007
Residential	**(2.6)%**	3.7%
Commercial	**(3.6)**	3.6
Industrial	**(6.3)**	0.2

In 2008, we distributed less electricity to residential and commercial customers due to milder weather and decreased usage per customer, partially offset by an increased number of customers. We distributed less electricity to industrial customers primarily due to decreased usage per customer.

In 2007, we distributed more electricity to residential customers due to colder winter weather and an increased number of customers, partially offset by decreased usage per customer. We distributed more electricity to commercial customers due to increased usage per customer, colder winter weather, and an increased number of customers. We distributed essentially the same amount of electricity to industrial customers.

Maryland Settlement Credit

As discussed in more detail in *Note 2 to Consolidated Financial Statements*, 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 estimated settlement of $188.2 million was accrued in the second quarter of 2008 and a total of $189.1 million was credited to customers in the third and fourth quarters 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. This means our monthly electric distribution revenues for residential and small commercial 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 Maryland's Senate Bill 1 related to residential electric rates in the *Business Environment Regulation Maryland Senate Bills 1 and 400* section.

Standard offer service revenues increased in 2008 compared to 2007 mostly due to higher standard offer service rates, partially offset by lower standard offer service volumes.

Standard offer service revenues increased in 2007 compared to 2006, primarily due to an increase in the standard offer service rates following the expiration of residential rate freeze service in July 2006, partially offset by lower standard offer service volumes.

Rate Stabilization Credits

As a result of Senate Bill 1, we were required to defer from July 1, 2006 until May 31, 2007 a portion of the full market rate increase resulting from the expiration of the residential rate freeze. In addition, we offered a plan also required under Senate Bill 1 allowing residential customers the option to defer the transition to market rates from June 1, 2007 until January 1, 2008.

Revenues in 2008 increased compared to 2007 due to lower rate stabilization credits as a result of the expiration of the rate stabilization plans.

In 2007 compared to 2006, revenues increased due to lower rate stabilization credits provided to residential electric customers as a result of the end of the first deferral period on May 31, 2007, partially offset by the additional deferrals during the second deferral period, which ended on December 31, 2007.

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 ending on December 31, 2009. The recovery of the first rate stabilization plan will occur over approximately ten years.

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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. We discuss the rate stabilization bonds in more detail in *Note 9 to Consolidated Financial Statements*.

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 our Calvert Cliffs Nuclear Power Plant and to suspend collection of the residential return component of the administrative charge collected through residential SOS rates through May 31, 2007. Under an order issued by the Maryland PSC in May 2007, as of June 1, 2007, we were required to reinstate collection of the residential return component of the administration charge in rates and to provide all residential electric customers a credit for the residential return component of the administrative charge. Under the Maryland settlement agreement, which is discussed in more detail in *Note 2 to Consolidated Financial Statements*, 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 2008 compared to 2007 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:

	2008	2007	2006
		(In millions)	
Actual costs	**$ 1,821.1**	$ 1,759.2	$ 1,489.7
Deferral under rate stabilization plan		(287.3)	(321.9)
Recovery under rate stabilization plans	**59.0**	28.5	
Electricity purchased for resale expenses	**$ 1,880.1**	$ 1,500.4	$ 1,167.8

Actual Costs

BGE's actual costs for electricity purchased for resale increased $61.9 million for 2008 compared to 2007, primarily due to higher contract prices to purchase electricity for our customers, partially offset by lower volumes.

BGE's actual costs for electricity purchased for resale increased $269.5 million for 2007 compared to 2006, primarily due to higher contract prices to purchase electricity for our residential customers following the expiration of contracts that were executed in 2000 as part of the implementation of electric deregulation in Maryland, partially offset by lower volumes.

Deferral under Rate Stabilization Plan

The deferral of the difference between our actual costs of electricity purchased for resale and what we are allowed to bill customers under Senate Bill 1 ended on December 31, 2007. Since July 1, 2006, we have deferred $609.2 million in electricity purchased for resale expenses. In 2007, we deferred $287.3 million in electricity purchased for resale expenses. These deferred expenses, plus carrying charges, are included in "Regulatory Assets (net)" in our, and BGE's, Consolidated Balance Sheets. We discuss the provisions of Senate Bill 1 related to residential electric rates in the *Business Environment Regulation Maryland Senate Bills 1 and 400* section.

Recovery under Rate Stabilization Plans

In late June 2007, we began recovering previously deferred amounts from customers related to our first rate stabilization plan. In April 2008, we began recovering previously deferred amounts from customers related to our second rate stabilization plan. We recovered $59.0 million in 2008 and $28.5 million in 2007 in deferred electricity purchased for resale expenses. These collections secure the payment of principal and interest and other ongoing costs associated with rate stabilization bonds issued by a subsidiary of BGE in June 2007.

Electric Operations and Maintenance Expenses

Regulated electric operations and maintenance expenses increased $4.4 million in 2008 compared to 2007 mostly due to increased uncollectible accounts receivable expense of $14.2 million, partially offset by $9.0 million of lower labor and benefit costs.

Regulated operations and maintenance expenses increased $24.8 million in 2007 compared to 2006 mostly due to higher labor and benefit costs and the impact of inflation on other costs of $16.9 million, customer education in relation to rate stabilization of $5.3 million, and increased uncollectible accounts receivable expense of $2.9 million.

Workforce Reduction Costs

During the fourth quarter of 2008, we executed a restructuring of the workforce. We recognized a $4.6 million pre-tax charge in 2008 related to this reduction in force.

We incurred no workforce reduction costs in 2007 or 2006.

Electric Depreciation and Amortization Expense

Regulated electric depreciation and amortization expense decreased $3.2 million in 2008 compared to 2007, primarily due to $10.0 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*

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Financial Statements. This decrease was partially offset by additional property placed in service in 2008.

Regulated electric depreciation and amortization expense increased $5.9 million in 2007 compared to 2006, primarily due to additional property placed in service.

Taxes Other Than Income Taxes

Taxes other than income taxes increased $5.3 million in 2007 in comparison with 2006, primarily due to increased property taxes.

Regulated Gas Business

Our regulated gas business is discussed in detail in *Item 1. Business Gas Business* section.

Results

	2008	2007	2006
		(In millions)	
Revenues	**$ 1,024.0**	$ 962.8	$ 899.5
Gas purchased for resale expenses	**(694.5)**	(639.8)	(581.5)
Operations and maintenance expenses	**(157.3)**	(157.5)	(144.8)
Workforce reduction costs	**(1.8)**		
Merger termination and strategic alternatives costs *			(1.4)
Depreciation and amortization	**(43.7)**	(46.8)	(46.0)
Taxes other than income taxes	**(35.4)**	(36.1)	(33.8)
Income from Operations	**$ 91.3**	$ 82.6	$ 92.0
Net Income	**$ 37.2**	$ 28.8	$ 37.0
Other Items Included in Operations (after-tax):			
Workforce reduction costs	**$ (1.0)**	$	$
Merger termination and strategic alternatives costs *			(0.4)
Total Other Items	**$ (1.0)**	$	$ (0.4)

Above amounts include intercompany transactions eliminated in our Consolidated Financial Statements. Note 3 provides a reconciliation of operating results by segment to our Consolidated Financial Statements.

* *Costs allocated to the regulated gas business during 2008 prior to the transaction with EDF have been allocated to the merchant energy segment.*

Net income from the regulated gas business increased $8.4 million in 2008 compared to 2007, primarily due to an increase in revenues less gas purchased for resale expenses of $4.0 million after-tax and reduced depreciation and amortization expense of $1.9 million after-tax.

Net income from the regulated gas business decreased $8.2 million in 2007 compared to 2006, primarily due to increased operations and maintenance expenses of $7.7 million after-tax.

Gas Revenues

The changes in gas revenues in 2008 and 2007 compared to the respective prior year were caused by:

	2008	2007

	(In millions)	
Distribution volumes	**$ (5.1)**	$ 19.3
Base rates	**(0.1)**	0.2
Revenue decoupling	**6.2**	(20.1)
Gas cost adjustments	**20.3**	74.4
Total change in gas revenues from gas system sales	**21.3**	73.8
Off-system sales	**40.3**	(11.2)
Other	**(0.4)**	0.7
Total change in gas revenues	**$ 61.2**	$ 63.3

Distribution Volumes

The percentage changes in our distribution volumes, by type of customer, in 2008 and 2007 compared to the respective prior year were:

	2008	**2007**
Residential	**(3.9)%**	17.7%
Commercial	**(3.1)**	14.6
Industrial	**2.8**	(11.3)

In 2008, we distributed less gas to residential customers and commercial customers 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 per customer, partially offset by a decreased number of customers.

In 2007, we distributed more gas to residential customers due to colder weather, increased usage per customer and an increased number of customers. We distributed more gas to commercial customers due to an increased number of customers and colder weather, partially offset by decreased usage per customer. We distributed less gas to industrial customers mostly due to decreased usage per customer.

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.

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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 to Consolidated Financial Statements*. 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 increased in 2008 compared to 2007 because we sold gas at higher prices, partially offset by less gas sold.

Gas cost adjustment revenues increased in 2007 compared to 2006 because we sold more gas at higher prices.

Off-System 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 BGE has satisfied its customers' demand, are not subject to gas cost adjustments. The Maryland PSC approved an arrangement for part of the margin from off-system sales to benefit customers (through reduced costs) and the remainder to be retained by BGE (which benefits shareholders). Changes in off-system sales do not significantly impact earnings.

Revenues from off-system gas sales increased in 2008 compared to 2007 because we sold gas at higher prices, partially offset by less gas sold.

Revenues from off-system gas sales decreased in 2007 compared to 2006 because we sold gas at lower prices, partially offset by more gas sold.

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 increased $54.7 million in 2008 compared to 2007 because we purchased gas at higher prices, partially offset by lower volumes.

Gas costs increased $58.3 million in 2007 compared to 2006 because we purchased more gas, partially offset by lower prices.

Gas Operations and Maintenance Expenses

Regulated gas operations and maintenance expenses increased $12.7 million in 2007 compared to 2006 mostly due to higher labor and benefit costs and the impact of inflation on other costs of $8.9 million and increased uncollectible accounts receivable expense of $1.2 million.

Gas Workforce Reduction Costs

During the fourth quarter of 2008, we executed a restructuring of the workforce at our operations. We recognized a $1.8 million pre-tax charge in 2008 related to this reduction in force.

We incurred no workforce reduction costs in 2007 or 2006.

Gas Depreciation and Amortization

Regulated gas depreciation and amortization expense decreased $3.1 million in 2008 compared to 2007, primarily due to $3.5 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*.

Gas Taxes Other Than Income Taxes

Gas taxes other than income taxes increased $2.3 million in 2007 compared to 2006, primarily due to increased property taxes.

Other Nonregulated Businesses

Results

	2008	2007	2006
		(In millions)	
Revenues	**$ 253.4**	$ 249.8	$ 231.0
Operating expenses	**(178.2)**	(173.5)	(173.1)
Merger termination and strategic alternatives costs			(0.5)
Workforce reduction costs	**(0.4)**		
Depreciation and amortization	**(68.2)**	(53.7)	(37.7)
Taxes other than income taxes	**(3.0)**	(2.4)	(2.0)
Income from Operations	**$ 3.6**	$ 20.2	$ 17.7
Income from continuing operations and before cumulative effects of changes in accounting principles (after-tax)	**$ 4.7**	$ 16.5	$ 11.3
Income from discontinued operations (after-tax)			0.9
Net Income	**$ 4.7**	$ 16.5	$ 12.2
Other Items Included In Operations (after-tax):			
Merger termination and strategic alternatives costs	**$**	$	$ (0.2)
Workforce reduction costs	**(0.3)**		
Total Other Items	**$ (0.3)**	$	$ (0.2)

Above amounts include intercompany transactions eliminated in our Consolidated Financial Statements. Note 3 provides a reconciliation of operating results by segment to our Consolidated Financial Statements.

Net income decreased $11.8 million in 2008 compared to 2007 primarily because the first quarter of 2007 included a gain related to a sale of a leasing arrangement that did not occur in 2008 and due to increased depreciation and amortization of $8.7 million after-tax.

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Net income from our other nonregulated businesses increased $4.3 million in 2007 compared to 2006, primarily due to higher construction volume at our energy projects business and a gain related to a sale of a leasing arrangement, partially offset by increased depreciation and amortization of $9.5 million after-tax.

Consolidated Nonoperating Income and Expenses

Gains on Sale of CEP Equity

Gains on sale of CEP equity decreased $63.3 million for the year ended December 31, 2008 as CEP, an equity investment of Constellation Energy, did not sell additional equity in 2008 as it had during 2007.

In November 2006, CEP completed an initial public offering of 5.2 million common units at $21 per unit. As a result of the initial public offering of CEP, we recognized a pre-tax gain of $28.7 million. As a result of subsequent sales of equity by CEP, which reduced our relative ownership percentage, we recognized pre-tax gains totaling $63.3 million in 2007. We discuss the issuances of CEP equity in more detail in *Note 2 to Consolidated Financial Statements*.

Other (Expense) Income

In 2008, we had other expenses of $52.3 million and, in 2007 we had other income of $158.6 million. The $210.9 million decrease in 2008 compared to 2007 is mostly due to lower interest and investment income as a result of a lower average cash balance of approximately $850 million and an increase in other-than-temporary impairment charges related to our nuclear decommissioning trust fund assets of $156.5 million.

Other income at BGE increased $2.8 million in 2008 compared to 2007 primarily due to an increase in equity funds capitalized on increased construction work in progress in 2008.

Other income increased $92.5 million in 2007 compared to 2006, mostly due to higher interest and investment income due to a higher cash balance.

Total other income at BGE increased $20.8 million in 2007 compared to 2006, primarily due to carrying charges related to rate stabilization deferrals of "Electricity Purchased for Resale" expense. We discuss the rate stabilization deferrals in more detail in the *Regulated Electric Business* section.

Fixed Charges

Fixed charges increased $56.7 million in 2008 compared to 2007 mostly due to a higher level of interest expense associated with the new debt issuances and higher amortization of debt issuance and credit facility costs.

Fixed charges at BGE increased $14.6 million in 2008 compared to 2007 mostly due to a higher level of interest expense associated with the new debt issuances and higher amortization of debt issuance and credit facility costs.

Fixed charges decreased $23.1 million in 2007 compared to 2006, mostly due to a lower average level of debt outstanding.

Fixed charges at BGE increased $22.7 million in 2007 compared to 2006 mostly due to interest expense recognized on debt that was issued in October 2006 and the rate stabilization bonds issued in June 2007.

Income Taxes

Our income tax expense decreased $506.6 million during 2008 compared to 2007 mostly due to a decrease in income before income taxes, which included approximately $1.2 billion of non-tax deductible merger termination and strategic alternatives costs, partially offset by the absence of synthetic fuel tax credits, which expired in 2007.

BGE's income tax expense decreased $75.3 million during 2008 compared to 2007 primarily due to lower pre-tax income as a result of the $189 million Maryland settlement credit recorded in 2008. We discuss the Maryland settlement agreement in more detail in *Note 2 to Consolidated Financial Statements.*

Our income taxes increased $77.3 million in 2007 compared to 2006 mostly because of an increase in pre-tax income and a decrease in synthetic fuel tax credits of $20 million.

In 2007, the State of Maryland increased its corporate income tax rate from 7% to 8.25%, effective January 1, 2008. The impact of adjusting all existing deferred income tax assets and liabilities for this change in the period of enactment was not material to us. However, this did impact BGE, as discussed below.

Income taxes at BGE decreased $6.2 million in 2007 compared to 2006, primarily due to lower pre-tax income partially offset by the increase in the Maryland state tax rate.

Defined Benefit Plans Expense and Funded Status

Our actual return on qualified pension plan assets for the purpose of computing annual net periodic pension cost in accordance with SFAS No. 87, *Employers' Accounting for Pensions* was a loss of 29.5% during 2008 as compared to our assumption of an expected annual return on pension plan assets of 8.75%. This loss reflects the substantial declines in financial markets experienced through 2008. As disclosed in *Note 7 to Consolidated Financial Statements*, we determine the expected return on pension plan assets component of our annual pension expense using a market-related value of pension plan assets that recognizes asset gains and losses over a five-year period. As a result of the losses incurred during 2008, our annual pension expense will increase beginning in 2009. Also, the lower fair value of our pension plan assets increased our unfunded pension obligation at December 31, 2008 and the related after-tax charge to "Accumulated other comprehensive loss" in accordance with SFAS No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans* (SFAS No. 158).

In addition to the losses experienced on our pension plan assets during 2008, there has also been a decrease in the discount rate we use to determine our defined benefit plan liabilities. At December 31, 2008, our discount rate assumption decreased to 6.00% from 6.25% in the prior year as a result of a decrease in interest rates. This will increase our pension and postretirement benefits expense beginning in 2009 and resulted in an increase in our unfunded obligation for those plans at December 31, 2008.

We disclose the SFAS No. 158 funded status adjustment at December 31, 2008, in *Note 7 to Consolidated Financial*

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Statements. In addition, effective January 1, 2009, we are reducing our expected annual return on pension plan assets from 8.75% to 8.50% based on updated analyses of projected future asset returns. As a result of the losses experienced on our qualified pension plan assets during 2008 and the reductions to our expected annual return on pension plan assets and discount rate assumptions, we expect our annual defined benefit plans cost will be higher by approximately $15 million pre-tax, for the next five years. In connection with the decline in our qualified pension plan funded status at December 31, 2008, we also expect to increase our annual qualified pension plan contributions from the $76 million we contributed in 2008 to an average level of approximately $180 million per year over the next five years. These expectations about future cost and funding levels are subject to material revision based on numerous factors including actual pension asset returns, future interest rate levels, impact of available liquidity on amount and timing of contributions, potential changes in regulatory requirements, plan design amendments, and demographic experience.

Allowance for Uncollectible Accounts Receivable

Our allowance for uncollectible accounts receivable increased $195.7 million from $44.9 million at December 31, 2007 to $240.6 million at December 31, 2008, related to our merchant energy business and regulated electric and gas businesses.

The increase in allowance for uncollectible accounts receivable from our merchant energy business was a result of counterparties with financial difficulties. The regulated electric and gas allowance for uncollectible accounts receivable increased $13.0 million in 2008 compared to 2007, mostly due to increased customer bills caused by higher standard offer service rates and the decreased ability of customers to pay their utility bills as a result of the economic downturn.

If the current economic recession continues on a prolonged basis, our and BGE's bad debt expense could increase in the future despite our efforts to mitigate those risks. We discuss our credit risk in more detail in the *Risk Management* section.

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Financial Condition

Cash Flows

The following table summarizes our 2008 cash flows by business segment, as well as our consolidated cash flows for 2008, 2007, and 2006.

	2008 Segment Cash Flows			Consolidated Cash Flows		
	Merchant	Regulated	Holding Company and Other	2008	2007	2006
	(In millions)					
Operating Activities						
Net (loss) income	$(1,357.4)	$ 38.3	$ 4.7	$(1,314.4)	$ 821.5	$ 936.4
Non-cash merger termination and strategic alternatives costs	541.8			541.8		
Other non-cash adjustments to net (loss) income	816.8	334.2	48.4	1,199.4	545.4	223.6
Changes in working capital						
Derivative assets and liabilities, excluding collateral	(750.5)	(2.0)	(5.4)	(757.9)	(138.2)	(286.1)
Net collateral and margin	(962.1)	1.8		(960.3)	49.6	(630.6)
Other changes	2.9	(45.0)	135.7	93.6	(242.4)	239.0
Defined benefit obligations (1)				(20.8)	(53.6)	40.5
Other	(6.1)	(35.1)	(14.5)	(55.7)	(54.5)	2.5
Net cash (used in) provided by operating activities	(1,714.6)	292.2	168.9	(1,274.3)	927.8	525.3
Investing Activities						
Investments in property, plant and equipment	(1,425.1)	(421.5)	(87.5)	(1,934.1)	(1,295.7)	(962.9)
Asset acquisitions and business combinations, net of cash acquired	(309.8)		(5.5)	(315.3)	(347.5)	(137.6)
Investment in nuclear decommissioning trust fund securities	(440.6)			(440.6)	(659.5)	(492.5)
Proceeds from nuclear decommissioning trust fund securities	421.9			421.9	650.7	483.7
Net proceeds from sale of gas-fired plants and discontinued operations						1,630.7
Issuances of loans receivable					(19.0)	(65.4)
Sale of investments and other assets	432.3	12.9	1.1	446.3	13.9	43.9
Contract and portfolio acquisitions					(474.2)	(2.3)
Decrease (increase) in restricted funds (2)	(16.6)	15.5	(941.7)	(942.8)	(109.9)	7.7
Other investments	23.2		(1.5)	21.7	(45.3)	54.8
Net cash (used in) provided by investing activities	(1,314.7)	(393.1)	(1,035.1)	(2,742.9)	(2,286.5)	560.1
Cash flows from operating activities less cash flows from investing activities	$(3,029.3)	$ (100.9)	$ (866.2)	(4,017.2)	(1,358.7)	1,085.4
Financing Activities (1)						
Net issuance (repayment) of debt (includes $1 billion proceeds from MidAmerican and $1 billion proceeds from EDF)				3,447.7	(33.1)	242.2
Debt issuance costs				(104.8)		
Proceeds from issuance of common stock				17.6	65.1	84.4
Common stock dividends paid				(336.3)	(306.0)	(264.0)
Reacquisition of common stock				(16.2)	(409.5)	
Proceeds from initial public offering of CEP						101.3
Proceeds from contract and portfolio acquisitions					847.8	221.3
Other				115.5	1.2	5.5
Net cash provided by financing activities				3,123.5	165.5	390.7

Net (decrease) increase in cash and cash equivalents	$ (893.7)	$ (1,193.2)	$ 1,476.1

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

(2) *The increase 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. These funds are held at the holding company and are restricted for payment of the 14% Senior Notes held by MidAmerican. The 14% Senior Notes were repaid in full in January 2009.*

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

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Cash Flows from Operating Activities

Cash used in operating activities was $1,274.3 million in 2008 compared to cash provided by operating activities of $927.8 million in 2007. This $2,202.1 million decrease in cash flows was primarily due to an increase in net collateral and margin posted, payments to MidAmerican to terminate our planned merger, payments in connection with the conversion of the Series A Preferred Stock, and credits rebated to BGE residential electric customers.

Total net cash collateral posted in 2008 increased as follows:

	(In millions)
Net collateral and margin posted, December 31, 2007	$ (485.3)
Return of collateral held associated with nonderivative contracts	(26.3)
Additional collateral posted associated with nonderivative contracts *	(330.5)
Additional initial and variation margin posted on exchange-traded transactions recorded in accounts receivable	(94.0)
Additional fair value net cash collateral posted (netted against derivative assets / liabilities) **	(509.5)
Change in net collateral and margin posted	(960.3)
Net collateral and margin posted, December 31, 2008	$(1,445.6)

* *Includes approximately $224 million of additional collateral posted due to certain counterparties that would not accept letters of credit issued by certain financial institutions.*

** *We discuss our netting of fair value collateral with our derivative assets / liabilities in more detail in Note 13 to Consolidated Financial Statements.*

The $960.3 million increase in net collateral and margin posted during 2008 primarily reflects the following:

- changes in commodity prices and the level of our open positions,
- increases in amounts posted to exchanges to meet initial margin requirements and changes in the rules governing exchange margin requirements, and
- additional collateral posted following our credit rating downgrades. We discuss our security ratings in more detail below. We discuss our downgrade collateral requirements in more detail in the *Collateral* section.

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

The remaining unfavorable change in cash used in operating activities in 2008 compared to 2007 was primarily due to the following:

- $663.0 million use of cash, consisting of $175 million paid to MidAmerican related to the termination of the merger, $418 million paid to MidAmerican for settling a portion of the conversion of the Series A Preferred Stock in cash, and $70 million paid to various parties for merger and other strategic alternatives costs,
- $189.1 million of credits rebated to residential electric customers by BGE as a result of the Maryland settlement agreement, and

$49.6 million of additional interest paid.

Cash provided by operating activities was $927.8 million in 2007 compared to $525.3 million in 2006. This $402.5 million favorable change was primarily due to an increase in non-cash adjustments to net income and favorable changes in working capital, offset in part by unfavorable changes in net income.

Non-cash adjustments to net income increased $321.8 million in 2007 compared to 2006, primarily due to the absence of a $191.4 million gain on sale of gas-fired plants and discontinued operations in 2006, a change in deferred fuel costs of $100.5 million related mostly to lower deferrals of electricity purchased for resale under the BGE rate stabilization plan, and a $98.2 million increase in deferred income tax expense.

Changes in working capital had a negative impact of $331.0 million on cash flows from operations in 2007 compared to a negative impact of $677.7 million in 2006. The improvement in working capital of $346.7 million was mainly due to a $680.2 million change in collateral related to changes in commodity prices and the level of our open positions, and a $147.9 million favorable change in working capital related to our derivative positions, partially offset by a $481.4 million unfavorable change in other components of working capital.

Cash Flows from Investing Activities

Cash used in investing activities was $2,742.9 million in 2008 compared to $2,286.5 million in 2007. The $456.4 million increase in cash used in 2008 compared to 2007 was primarily due to:

- the increase in restricted cash of $832.9 million, primarily relating to the $1 billion proceeds received from the issuance of Series B Preferred Stock to EDF that is restricted to pay the 14% Senior Notes. The proceeds from the Series B Preferred Stock issuance, as discussed in the cash flows from financing section below, are the source of the funds for the increase in restricted cash. The 14% Senior Notes were subsequently paid in January 2009.

- the increase in investments in property, plant and equipment of $638.4 million. This increase was primarily driven by environmental spending of $467 million for our Brandon Shores coal-fired generating plant and $48 million in construction costs at our partially completed gas-fired combined cycle power generating facility in Alabama.

These increased uses of cash in investing activities are partially offset by the absence in 2008 of $474.2 million of cash used in 2007 for contract and portfolio acquisitions, which we discuss in more detail below, and approximately $432.4 million of higher proceeds received from sales of investments in 2008 compared to 2007. The proceeds in 2008 include $150 million of cash received from EDF that we will record as additional

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proceeds for EDF's purchase of 49.99% membership interest in our nuclear generation and operation business.

Cash used in investing activities was 2,286.5 million in 2007 compared to cash provided by of $560.1 million in 2006. The $2,846.6 million unfavorable change in 2007 compared to 2006 was primarily due to the following:

- the absence of the net proceeds of $1,630.7 million from the sale of gas-fired plants and discontinued operations received in 2006,
- a $471.9 million increase in contract and portfolio acquisitions that we discuss in more detail below,
- a $332.8 million increase in investments in property, plant, and equipment primarily related to growth within our merchant segment, which includes spending related to environmental controls at our generating facilities, and
- a $209.9 million increase in acquisitions, primarily related to our acquisitions of working interests in gas and oil producing properties and a retail competitive supply business as discussed in more detail in *Note 15 to Consolidated Financial Statements*.

Cash Flows from Financing Activities

Cash provided by financing activities was $3,123.5 million in 2008 compared to $165.5 million in 2007. The increase of $2,958.0 million was primarily due to the issuance of:

- $1 billion of mandatorily redeemable Series B Preferred Stock to EDF, the proceeds of which are reflected in the increase in restricted cash, as discussed in the cash flows from investing activities above,
- $1 billion of mandatorily redeemable convertible Series A Preferred Stock to MidAmerican, which was converted, in part, in December 2008 into $1 billion of 14% Senior Notes, which were repaid in full in January 2009,
- $250.0 million of Zero Coupon Notes,
- $450.0 million of 8.625% Series A Junior Subordinated Debentures, and
- $400.0 million of 6.125% Notes by BGE.

Cash provided by financing activities was $165.5 million in 2007 compared to $390.7 million in 2006. The unfavorable change of $225.2 million was primarily due to cash used for reacquisition of common stock of $409.5 million, a net decrease in cash related to changes in short-term borrowings and long-term debt of $275.3 million, and a net decrease of $101.3 million in proceeds from the initial public offering of CEP in 2006. This was partially offset by an increase in gross proceeds from contract and portfolio acquisitions of $626.5 million, which we discuss below.

In October 2007, our Board of Directors approved a common share repurchase program for up to $1 billion of our outstanding common shares. Subsequent to this approval, on October 31, 2007, we entered into an accelerated share repurchase agreement with a financial institution, and on November 2, 2007 we purchased 2,023,527 of outstanding shares of our common stock for $250 million. We did not repurchase any shares under this program during 2008. We discuss the share repurchase program in more detail in *Note 9 to Consolidated Financial Statements*.

Contract and Portfolio Acquisitions

During 2007 and 2006, our merchant energy business acquired several pre-existing energy purchase and sale agreements, which generated significant cash flows at the inception of the contracts. These agreements had contract prices that differed from market prices at closing, which resulted in cash payments from the counterparty at the acquisition of the contract. We received net cash of $373.6 million in 2007 and $219.0 million in 2006 for various contract and portfolio acquisitions. We reflect the underlying contracts on a gross basis as assets or liabilities in our Consolidated Balance Sheets depending on whether they were above- or below-market prices at closing; therefore, we have also reflected them on a gross basis in cash flows from investing and financing activities in our Consolidated Statements of Cash Flows as follows:

Year ended December 31,	**2008**	**2007**	**2006**

		(In millions)	
Financing activities proceeds from contract and portfolio acquisitions	**$**	$ 847.8	$ 221.3
Investing activities contract and portfolio acquisitions		(474.2)	(2.3)
Cash flows from contract and portfolio acquisitions	**$**	$ 373.6	$ 219.0

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

We discuss certain of these contract and portfolio acquisitions in more detail in *Note 5 to Consolidated Financial Statements.*

Security Ratings

Independent credit rating agencies rate Constellation Energy's and BGE's fixed-income securities. The ratings indicate the agencies' assessment of each company's ability to pay interest, distributions, dividends, and principal on these securities. These ratings affect how much it will cost each company to sell these securities and, in certain cases, the company's ability to access the markets to sell securities. Generally, the better the rating, the lower the cost of the securities to each company when they sell them. A reduction in our credit ratings could have an adverse effect on our access to liquidity sources, increase our cost of funds, trigger additional collateral requirements, and/or decrease

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the number of investors and counterparties willing to transact with us.

The factors that credit rating agencies consider in establishing Constellation Energy's and BGE's credit ratings include, but are not limited to, cash flows, liquidity, business risk profile, stock price volatility, political, legislative and regulatory risk, interest charges relative to operating cash flow, and the level of debt relative to operating cash flows and to total capitalization.

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

	Standard & Poors Rating Group	Moody's Investors Service	Fitch-Ratings
Constellation Energy			
Senior Unsecured Debt	BBB	Baa3	BBB
Commercial Paper	A-2	P-3	F2
Junior Subordinated Debentures	BB+	Ba1	BBB-
BGE			
Senior Unsecured Debt	BBB	Baa2	A-
Commercial Paper	A-2	P-2	F2
Rate Stabilization Bonds *	AAA	Aaa	AAA
Trust Preferred Securities	BB+	Baa3	BBB+
Preference Stock	BBB	Baa2	BBB+

* *Bonds issued by RSB BondCo LLC, a subsidiary of BGE*

The ratings in the above table reflect the following outlooks by the credit rating agencies:

Constellation Energy:

Standard & Poors Rating Group Watch Negative

Moody's Investors Service Under review for possible downgrade

FitchRatings Watch Evolving

BGE:

Standard & Poors Rating Group Watch Negative

Moody's Investors Service Stable

FitchRatings Watch Evolving

We remain committed to maintaining a stable investment grade credit profile and to meeting our liquidity requirements. We discuss our available sources of funding in more detail below.

We discuss the potential effect of a ratings downgrade in the *Available Source of Funding* and *Collateral* sections.

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, hedging our Customer Supply business in both power and gas, and hedging our coal businesses. 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. The current disruptions in the credit and capital markets have made it more difficult for us to raise capital and access the credit necessary to obtain sufficient liquidity to meet our business requirements.

Constellation Energy

At December 31, 2008, we had approximately $6.2 billion in committed credit facilities available as shown below. We have also included the pro forma effect on our credit facilities, which are reduced or terminated upon the occurrence of certain events, 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 (A)	1.23	
June 2009 (B)	0.60	
September 2013	0.35	
December 2009	0.15	
Total	$6.18	$ 2.32

(A) *Size of facility may be reduced by proceeds received from certain securities offerings or asset sales.*

(B) *We discuss this facility provided by EDF in more detail in Note 8 to Consolidated Financial Statements. Terminates at the earliest of satisfying conditions to exercise the put on assets having a value of at least $600 million under the put arrangement discussed in Note 8 to Consolidated Financial Statements, receipt of alternative financing of $600 million, or June 2009.*

Collectively, these facilities currently support the issuance of letters of credit and/or cash borrowings up to $6.2 billion. In late September 2008, we were unable to issue commercial paper to replace maturing commercial paper and meet other obligations. Instead, we borrowed $485.7 million under one of our credit facilities to secure funds. At December 31, 2008, we had no commercial paper outstanding. During the month of January 2009, Constellation Energy issued no commercial paper. We may utilize commercial paper as a primary source of short-term debt if market conditions return to normal.

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.

Our ability to exercise the put arrangement is contingent on certain regulatory approvals that we expect will be received

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for all assets covered by the arrangement by April 2009, except for Safe Harbor Water Power Corporation, which is expected by the third quarter of 2009. In addition, exercise of the put option is conditioned upon 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. 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.

Certain credit facilities of Constellation Energy contain a provision requiring Constellation Energy to maintain a ratio of debt to capitalization equal to or less than 65%. At December 31, 2008, the debt to capitalization ratios as defined in the credit agreements were no greater than 57%.

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 senior unsecured debt rating is BBB- or lower and our Moody's senior unsecured debt rating is Baa3 or lower.

The terms of the Series B Preferred Stock allows 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 if the Investment Agreement with EDF has closed or been terminated and our Standard & Poors Rating Group 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. In 2008, in response to the temporary lack of liquidity in the commercial paper market, BGE drew $370 million on its $400 million credit facility to secure funds in advance of maturing commercial paper and other obligations.

At December 31, 2008, BGE had no commercial paper outstanding. During the month of January 2009, BGE issued no commercial paper. BGE may utilize commercial paper as a primary source of short-term debt if market conditions return to normal.

The credit agreement of BGE contains a provision requiring BGE to maintain a ratio of debt to capitalization equal to or less than 65%. At December 31, 2008, the debt to capitalization ratio for BGE as defined in this credit agreement was 55%.

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 2007:

	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 December 31, 2007		
	Constellation Energy	BGE	Total Consolidated
	(In billions)		
Credit facilities	$ 4.1	$ 0.4	$ 4.5
Less: Letters of credit issued	(1.8)		(1.8)
Less: Cash drawn on credit facilities			
Undrawn facilities	2.3	0.4	2.7
Less: Commercial paper outstanding			
Net available facilities	2.3	0.4	2.7
Add: Cash	1.1		1.1
Net available liquidity	$ 3.4	$ 0.4	$ 3.8

Net available liquidity decreased during 2008 by approximately $1.5 billion as follows:

	(In billions)
Increase in letters of credit issued	$ (1.8)
Decrease in cash	(0.9)
Increase in cash drawn on credit facilities	(0.9)
Increase in credit facilities	2.1
Decrease in net available liquidity	$ (1.5)

The increase in letters of credit issued and the decrease in cash was primarily due to increased collateral requirements. We discuss our changes in collateral during 2008 in more detail in the *Collateral* section. We discuss the impact of the higher cash collateral posting in the *Financial Condition Cash-Flows* section.

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The change in credit facilities was due to the following:

- executed a new agreement for $1.23 billion in November 2008,
- executed an agreement with EDF for credit support totaling $600 million in December 2008, which is discussed in more detail in *Note 8 to Consolidated Financial Statements*,
- executed an agreement for a total of $500 million in June 2008, of which $350 million expires in 2013 and $150 million expires in 2009, and
- the expiration of a facility totaling $250 million in December 2008.

The following table provides our net available liquidity at January 31, 2009:

	As of January 31, 2009		
	Constellation Energy	**BGE**	**Total Consolidated**
		(In billions)	
Credit facilities	$ 6.2	$ 0.4	$ 6.6
Less: Letters of credit issued	(3.5)		(3.5)
Less: Cash drawn on credit facilities	(1.2)	(0.4)	(1.6)
Undrawn facilities	1.5		1.5
Less: Commercial paper outstanding			
Net available facilities	1.5		1.5
Add: Cash	0.8		0.8
Net available liquidity	$ 2.3	$	$ 2.3

Net available liquidity was unchanged at January 31, 2009 compared to December 31, 2008. However, we executed additional cash draws from our credit facilities of $0.7 billion primarily due to working capital requirements for our power and natural gas settlements.

As a result of the significant events of 2008, we have made substantial changes in our strategy to improve our liquidity and our credit profile, including focusing on the following immediate goals:

- reducing the collateral and liquidity needs of our Global Commodities and Customer Supply operations,
- executing strategic initiatives for our Global Commodities operation, which we discuss in more detail in the *Merchant Energy Business Background* section,
- focusing on our core strengths, including owning, developing, and operating nuclear and non-nuclear generation assets, providing regulated utility service to customers, and maintaining strong supply relationships with retail and wholesale customers, and
- working to close the sale of EDF of 49.99% of our nuclear generation and operation business as expeditiously as possible.

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. Also, we are exposed to certain operational risks that could have a significant impact on our liquidity. We discuss these risks in more detail in the *Risk Factors* section.

We believe that the actions that we have taken will be sufficient to meet our ongoing liquidity requirements over the next 12 months. However, if we cannot successfully execute on our strategies and/or actual changes in commodity prices differ from our estimates, our available liquidity would be negatively affected, which would have a material adverse effect on our financial results and condition.

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 goal of remaining economically hedged in our Generation and power and gas Customer Supply operations, third party coal business, and our trading activities. 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, Intercontinental Exchange, and NOS Clearing ASA. 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 as a result of changes in exchange rules and decreased during the fourth quarter as a result of portfolio risk reduction and downsizing activities. 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 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 third party coal business, we generally buy coal from suppliers that do not post collateral, but we enter into physical or financial sales contracts that require us to post collateral.
- 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

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through purchases of power and gas that generally require us to post collateral.

In our Generation operation, we may have to post collateral on our power sale or fuel purchase contracts, but our generating plants are not a source of collateral.

Constellation Energy is required to post collateral in the form of either cash or letters of credit. In an environment of stable commodity prices, Constellation Energy's net collateral position is relatively stable. However, during 2008, the energy markets were affected by large fluctuations in commodity prices as can be seen in the following table summarizing changes in spot prices during 2008:

Increases (decreases) from December 31, 2007	Six months ended June 30, 2008	Nine months ended September 30, 2008	Year ended December 31, 2008
Power	33%	(8)%	(30)%
Natural gas	44%	(5)%	(30)%
Coal	153%	58%	(1)%
Crude oil	55%	1%	(40)%

The price variability in 2008 impacted our posting of cash and letters of credit in 2008 as follows:

	Six months ended June 30, 2008	Six months ended December 31, 2008	Year ended December 31, 2008
		(In millions)	
Additional (return of) collateral held associated with nonderivative contracts	$ 345.5	$ (371.8)	$ (26.3)
Additional collateral posted associated with nonderivative contracts	(123.9)	(206.6)	(330.5)
(Additional) return of initial and variation margin posted on exchange-traded transactions recorded in accounts receivable	(428.0)	334.0	(94.0)
(Additional) return of fair value net cash collateral posted (netted against derivative assets/liabilities)	732.3	(1,241.8)	(509.5)
Source (use) of cash collateral	525.9	(1,486.2)	(960.3)
Letters of credit (issued by) returned to us	(2,522.9)	716.6	(1,806.3)
Total use of collateral	$(1,997.0)	$ (769.6)	$ (2,766.6)

During the first half of 2008, increasing power prices caused certain hedges of our customer supply load to move deeply in-the-money, driving up the cash collateral and letters of credit posted by counterparties to us. However, letters of credit posted to us do not affect our liquidity position. At the same time, rising international coal prices required us to post additional cash and letters of credit to collateralize out-of-the money hedges of our international coal sales. These two impacts resulted in a net reduction in our use of cash collateral as we received more cash than we posted. However, there was a significant increase in our posting of letters of credit.

During the second half of the year, our use of collateral postings remained fairly constant despite our fourth quarter portfolio downsizing. Portfolio downsizing led to decreases in the levels of collateral posted to exchanges to support initial margin requirements, as well as the collateral posted to ISOs. However, as commodity prices have fallen, the hedges of our customer supply load moved out-of-the money, causing us to post significant amounts of cash collateral to our counterparties. This collateral outflow for power positions was partially offset by the collateral inflow since June 2008 on our international coal hedges, which have become significantly less out-of-the money as coal prices have fallen.

The net impact of all of these price changes, as well as the portfolio downsizing has resulted in a net increase in our use of collateral of $2.8 billion for 2008.

We discuss our use of cash collateral further in the *Financial Condition* section and we discuss our letters of credit usage further in the *Net Available Liquidity* section.

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 December 31, 2008 and January 31, 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	$ 1.8

*

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

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 ratings in the *Security Ratings* section. We discuss our credit facilities in the *Available Sources of Funding* section.

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Capital Resources

Our actual consolidated capital requirements for the years 2006 through 2008, along with the estimated annual amount for 2009, are shown in the following table.

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* and *Item 1A. Risk Factors* sections.

	2006	**2007**	**2008**	**2009 (Estimate)**
		(In billions)		
Nonregulated Capital Requirements:				
Merchant energy (excludes acquisitions)				
Generation plants	$ 0.3	$ 0.2	$ 0.6	$ 0.4
Environmental controls		0.2	0.5	0.3
Portfolio acquisitions/investments	0.2	0.5	0.2	0.2
Technology/other	0.2	0.2	0.1	0.1
Nuclear fuel	0.1	0.1	0.2	0.2
Total merchant energy capital requirements	0.8	1.2	1.6	1.2
Other nonregulated capital requirements		0.1	0.1	
Total nonregulated capital requirements	0.8	1.3	1.7	1.2
Regulated Capital Requirements:				
Regulated electric	0.3	0.3	0.4	0.4
Regulated gas	0.1	0.1	0.1	0.1

Total regulated capital requirements	0.4	0.4	0.5		0.5
Total capital requirements	$ 1.2	$ 1.7	$ 2.2	$	1.7

As of the date of this report, we estimate our 2010 capital requirements will be approximately $1.1 billion. This amount excludes the capital requirements related to our nuclear generation and operation business that is expected to be deconsolidated in 2009 as a result of the closing of the Investment Agreement with EDF.

Capital Requirements

Merchant Energy Business

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

- improvements to generating plants,
- nuclear fuel costs,
- costs of complying with the Environmental Protection Agency (EPA), Maryland, and Pennsylvania environmental regulations and legislation, and
- enhancements to our information technology infrastructure.

Regulated Electric and Gas

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

Funding for Capital Requirements

The current disruptions in the credit and capital markets as well as counterparty concerns about our financial condition have made it more difficult for us to raise capital and access the credit necessary to provide sufficient liquidity to meet our business requirements. We discuss our available sources of funding and strategy to improve liquidity in the *Available Sources of Funding* section.

Merchant Energy Business

We expect to fund the capital requirements of our merchant energy business with internally generated cash and other available sources. To the extent that internally generated cash is not sufficient to meet those requirements, we would seek additional funding from the money markets, capital markets and lease markets, subject to credit conditions and market liquidity, and, if necessary, from drawdowns on credit facilities.

The projects that our merchant energy business develops typically require substantial capital investment. Many of the qualifying facilities and independent power projects that we have an interest in are financed primarily with non-recourse debt that is repaid from the project's cash flows. This debt is collateralized by interests in the physical assets, major project contracts and agreements, cash accounts and, in some cases, the ownership interest in that project.

Regulated Electric and Gas

We expect to fund capital expenditures associated with our regulated electric and gas businesses with internally generated cash. To the extent that internally generated cash is not sufficient to meet those requirements, we would seek additional funding from the money markets, capital markets (including trust preferred securities or preference stock), subject to credit conditions and market liquidity, and, if necessary, from drawdowns on credit facilities. BGE may also receive equity contributions from time to time from Constellation Energy. BGE also participates in a cash pool administered by Constellation Energy as discussed in *Note 16 to Consolidated Financial Statements*.

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Other Nonregulated Businesses

We expect to fund the capital requirements of our other nonregulated businesses with internally generated cash. To the extent that internally generated cash is not sufficient to meet those requirements, we would seek additional funding from the money markets, capital markets and lease markets, subject to credit conditions and market liquidity, and, if necessary, from drawdowns on credit facilities. We may also consider sales of securities and assets, and/or from time to time equity contributions from Constellation Energy.

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 as of December 31, 2008 in the following table:

	Payments				
	2009	2010-2011	2012-2013	Thereafter	Total
	(In millions)				
Contractual Payment Obligations					
Long-term debt: (1)					
Nonregulated					
Principal	$2,501.5	$ 0.5	$ 734.8	$ 2,671.2	$ 5,908.0
Interest	409.1	315.0	258.1	3,009.9	3,992.1
Total	2,910.6	315.5	992.9	5,681.1	9,900.1
BGE					
Principal	65.0	138.2	639.1	1,422.8	2,265.1
Interest	134.5	258.1	231.3	1,336.6	1,960.5
Total	199.5	396.3	870.4	2,759.4	4,225.6
BGE preference stock				190.0	190.0
Operating leases (2)	314.8	469.5	405.4	591.4	1,781.1
Purchase obligations: (3)					
Purchased capacity and energy (4)	588.4	282.2	187.5	227.3	1,285.4
Fuel and transportation	1,648.5	1,531.4	718.0	1,292.2	5,190.1
Other	269.1	87.8	40.6	29.3	426.8
Other noncurrent liabilities:					
FIN 48 tax liability		26.2	102.4	12.8	141.4
Pension benefits (5)	238.7	369.4	385.1		993.2
Postretirement and post employment benefits (6)	40.0	91.8	105.6	237.9	475.3
Total contractual payment obligations	$6,209.6	$3,570.1	$3,807.9	$ 11,021.4	$24,609.0

(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 $250.8 million early through remarketing features. Interest on variable rate debt is included based on 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 to Consolidated Financial Statements.

(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 for contributions for our qualified pension plans and participant payments for our nonqualified pension plans. Refer to Note 7 to Consolidated Financial Statements 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 as discussed in Note 7 to Consolidated Financial Statements.

Off-Balance Sheet Arrangements

For financing and other business purposes, we utilize certain off-balance sheet arrangements that are not reflected in our Consolidated Balance Sheets. Such arrangements do not represent a significant part of our activities or a significant ongoing source of financing.

We use these arrangements when they enable us to obtain financing or execute commercial transactions on favorable terms. As of December 31, 2008, we have no material off-balance sheet arrangements, including:

- guarantees with third-parties that are subject to the initial recognition and measurement requirements of FASB Interpretation No. 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness to Others*,
- retained interests in assets transferred to unconsolidated entities,
- derivative instruments indexed to our common stock, and classified as equity, or
- variable interests in unconsolidated entities that provide financing, liquidity, market risk, or credit risk support, or engage in leasing, hedging or research and development services.

At December 31, 2008, Constellation Energy had a total face amount of $16.4 billion in guarantees outstanding, of which $15.0 billion related to our merchant energy business. These amounts generally 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 $3 billion at December 31, 2008, which represents the total amount the parent company could be required to fund based on December 31, 2008 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 *Note 12 to Consolidated Financial Statements* and our significant variable interests in *Note 4 to Consolidated Financial Statements*.

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Risk Management

Introduction

Constellation Energy is exposed to market, credit, operational, and business risks that are fundamental to our business of providing products and services across the energy value chain.

In general, the risks in our businesses can be classified as one of the following:

- Market Risk risk related to changes in energy commodity prices, load requirements, location and supply, and market rules,
- Credit Risk risk related to a customer's or supplier's inability to fulfill its contractual obligations due to financial distress,
- Operational Risk risk associated with human error or a failure of process and systems, or external factors, and
- Business Risk risk of unsuccessful business performance due to changing economic conditions, competition, regulatory environment, legislation, and economic conditions.

These risks exist in our business with varying levels of exposure, and are interrelated and cannot be managed in isolation.

Each of the four risk classifications noted above can be affected by numerous internal and external forces, including:

- economic conditions,
- market liquidity,
- competition,
- country or sovereign issues,
- systems or process failure, and
- fiscal and monetary policies.

As a result of the extent and diversity of the risks the Company faces in its business operations, we analyze risk at transaction, portfolio, business, and enterprise-wide levels to ensure that material risks are identified and managed effectively. We utilize numerous methods to evaluate and measure risks. In general, we evaluate risks in terms of the impact on our earnings, liquidity, strategic objectives, credit rating, reputation, and values. We identify and evaluate risks based not only on their probability of occurring and magnitude of impact on the financial statements, but also with respect to the potential for significant or unexpected shifts in market conditions or rules.

We recognize the importance of managing risk as a key differentiator in the energy business and view the active and effective management of the risks in our businesses to be of paramount importance. To foster a culture of risk awareness and management, we employ a risk management framework to identify, assess, monitor, manage, and report risks. Our risk management program is based on established policies and procedures to manage risks, combined with an extensive system of internal controls. Nevertheless, no system of risk management can cost-effectively eliminate all risks to which an entity is exposed. Thus, in particular environments, the Company may not be able to mitigate risk exposures to the level desired and may have exposures to certain risk factors that cannot be mitigated.

As previously discussed, the collapse of the credit markets and the extreme volatility in energy prices in 2008 significantly impacted Constellation Energy's operating results and financial condition.

We reviewed our risk management approach in light of the unprecedented market events of 2008 and their implications for the future, and we are updating and strengthening certain of our policies, measures, and processes. We are taking active steps to incorporate the lessons learned in 2008 in our existing risk management and control frameworks as well as in the structure and processes of our risk management organization.

These steps include enhancing our collateral and liquidity stress testing capabilities as well as our data integrity reviews and systems capabilities and controls. For example, we have continued our focus on value at risk (VaR) as a measure of market risk and supplemented this measure with economic value at risk (EVaR). We have also continued our practice of utilizing stress tests and broader position limits based on market liquidity and have enhanced these capabilities throughout 2008.

In this section, we will review the Company's risk in terms of our:

- risk governance,
- risk controls, and
- risk exposures.

Risk Governance

As has been our practice, the Audit Committee of the Board of Directors periodically reviews compliance with our risk parameters, limits, and trading guidelines, and our Board of Directors has established a VaR limit. As discussed below, we have a Risk Management Group (RMG) that is responsible for monitoring the key business risks, enforcing compliance with risk management policies and risk limits, as well as managing credit risk. The RMG reports to the Chief Risk Officer, who provides regular risk management updates to the Audit Committee and the Board of Directors.

We also have a Risk Management Committee (RMC) that is responsible for establishing risk management policies, reviewing procedures for the identification, assessment, measurement, and management of risks, and monitoring and reporting risk exposures. The RMC meets on a regular basis and is chaired by our Chief Risk Officer, and consists of our Chief Executive Officer, our Chief Financial Officer, our Vice Chairman, and business unit leaders. In addition, the Chief Risk Officer coordinates with the risk management committees at the business units that meet regularly to identify, assess, and quantify material risk issues and to develop strategies to manage these risks.

In an effort to manage market and credit risks, Constellation Energy has established a series of limits that reflect the Company's risk tolerances in the context of the market environment and our business strategy. In setting limits, the Company takes into consideration factors such as market volatility, product liquidity, business trends, and management experience. The Company maintains different limits at the corporate and business unit levels. Business units are responsible for adhering to established limits, against which exposures are monitored and reported. Limit breaches are reported in a timely manner to senior management, who consults with the business

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unit on an appropriate course of action for instance, reducing trading positions.

Risk Controls

Risk controls are applied at the level of individual exposures and portfolios of exposures in each business and to risk in aggregate, across all businesses and major risk types, relative to the Company's risk capacity.

Constellation Energy's RMG is an independent function tasked with providing an independent quantification and assessment of key business risks, as well as providing an evaluation of individual risk components that contribute to the Company's consolidated risk profile. The RMG is also responsible for establishing risk policies, maintaining appropriate risk controls, ensuring compliance with policies and procedures, and monitoring methods according to the risk parameters established by the Board of Directors.

The RMG consists of five divisions that focus on a specialized area of risk.

Wholesale and Retail Credit Risk Management

Wholesale Credit Risk Management establishes guidelines necessary for rating counterparties and assigning limits. This group supports the business units by establishing credit relationships with various counterparties and facilitating market liquidity with limits and appropriate credit terms and conditions. The Retail Credit Risk Management group works as a partner with our retail customer-facing operations to manage credit risks associated with our retail supply businesses. This group evaluates credit and manages overall credit exposure for the retail operation.

Credit risk managers are responsible for enforcing credit policies, including monitoring, reporting, escalating, and mitigating trade violations and limit exceptions.

Market Risk Management

Market Risk Management is responsible for effectively identifying, monitoring, and reporting on market risk, to include price volatility, market liquidity, and portfolio risk management. Their key responsibilities are to identify market risk exposures including commodity, interest rate, and foreign exchange risk, and to monitor both physical and financial portfolio positions. This group also enforces the Market Risk policies and ensures compliance with these policies, including the monitoring, analyzing, and escalating of market risk controls, such as exposure limits and price verification results.

Collateral Risk Management

Collateral Risk Management is responsible for providing an integrated view on credit, market, and company liquidity risks to manage the Company's collateral position. This group's responsibilities include measuring and monitoring collateral outflow, downgrade collateral needs, and collateral use across the Company. Additionally, this group estimates potential collateral requirements due to market shifts, hedging strategies, and adjustments to the Company's credit ratings. Finally, Collateral Risk Management assists the businesses in determining the strategic use of collateral and the appropriate cost of collateral for transactions.

Operational Risk Management

Each business area maintains responsibility for operational risk management. A corporate staff oversees implementation of a common framework for defining, measuring, monitoring, and reporting operational risks.

Risk Infrastructure

Risk Infrastructure supports the risk management divisions and consolidates risk exposures across the businesses and disciplines. This group's responsibilities include risk and credit systems design and maintenance, risk metric development and calculation, controls structure and enforcement, and risk reporting. In addition, the Risk Infrastructure Group provides analytical support to the risk functions, validates company models, and verifies liquid and illiquid forward price curves and volatilities. Finally, this group performs independent risk assessments, due diligence, and risk adjusted valuations of transactions, mergers and acquisitions, and large capital projects.

Risk Exposures

We manage risks across our merchant energy, regulated electric, and regulated gas businesses. We summarize below the risks we manage within each of our businesses.

Merchant Energy Business

Our merchant energy business is exposed to various risks in the competitive marketplace that may materially impact our financial results and affect our earnings. These risks include changes in commodity prices, potential imbalances in supply and demand, credit risk and operational risk.

Regulated Electric Business

BGE does not own or operate any electric generating facilities. Therefore, BGE's regulated electric business is exposed to market price risk. To mitigate this, BGE obtains energy and capacity to provide SOS through a competitive bidding process approved by the Maryland PSC. We discuss SOS and the impact on base rates in more detail in *Item 1. Business Baltimore Gas and Electric Company Electric Business* section. As a result of this process, BGE's exposure to market price risk is limited, and at December 31, 2008, our exposure to commodity price risk for our regulated electric business was not material. However, BGE may enter into electric futures, options, and swaps to hedge its market price risk if appropriate. We discuss this further in *Note 13*.

BGE's regulated electric business is also exposed to wholesale credit risk from its suppliers as well as retail credit risk from its customers. Finally, BGE is subject to operational risks, including potential impacts from storms and distribution asset failures.

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Regulated Gas Business

BGE acquires all of its natural gas for delivery to customers from third-party suppliers. Therefore, BGE's regulated gas business is exposed to market price risk. However, BGE recovers the costs of purchased gas under the market-based rates incentive mechanism approved by the Maryland PSC. Additionally, BGE may enter into gas futures, options, and swaps to hedge its price risk under our market-based rate incentive mechanism and our off-system gas sales program as appropriate. We discuss this further in *Note 13*. At December 31, 2008, our exposure to commodity price risk for our regulated gas business was not material.

BGE's regulated gas business is also exposed to wholesale credit risk from its suppliers as well as retail credit risk from its customers. Finally, BGE is subject to operational risks, including potential impacts from storms and distribution asset failures.

Risk Exposure Categories

The various categories of risk exposures that we manage include, but are not limited to, market risk, which includes interest rate risk, security price risk, and foreign currency risk; credit risk, which includes wholesale and retail; and operational risk. As noted above, these risks may be common to more than one of our businesses. We discuss each of these primary risk exposure categories separately below.

Market Risk

We are exposed to the impact of market fluctuations in the price and transportation costs of power, natural gas, coal, and other commodities. These risks arise from our ownership and operation of power plants, our customer supply operations, and our origination, risk management, and trading activities. These commodity price risks arise from:

- the potential for changes in the price of, and transportation costs for, electricity, natural gas, coal, and other commodities, and
- changes in interest rates.

A number of factors associated with the structure and operation of the energy markets influence the level and volatility of prices for energy commodities and related derivative products. We use such commodities and products in our merchant energy business, and if we do not hedge the associated financial exposure, this commodity price volatility could affect our earnings. These factors include:

- seasonal, daily, and hourly changes in demand,
- extreme peak demands due to weather conditions,
- available supply resources,
- transportation availability and reliability within and between regions,
- location of our generating facilities relative to the location of our load-serving obligations,
- procedures used to maintain the integrity of the physical power system during extreme conditions,
- changes in the nature and extent of federal and state regulations, and
- geopolitical concerns affecting global supply of coal, oil, and natural gas.

These factors can affect energy commodity and derivative prices in different ways and to different degrees. These effects may vary throughout the world as a result of regional differences in:

- weather conditions,
- market liquidity,

- capability and reliability of the physical power and gas systems, and
- the nature and extent of power market restructuring.

Additionally, we have fuel requirements that are subject to future changes in coal, natural gas, uranium, and oil prices. Our power generation facilities purchase fuel under contracts or in the spot market. Fuel prices may be volatile, and the price that can be obtained from electricity sales may not change at the same rate or in the same direction as changes in fuel costs. This could have a material adverse impact on our financial results.

As part of our overall portfolio, we manage the market risk of our merchant energy business, including electricity sales, fuel and energy purchases, emission credits, interest rate and foreign currency risks, weather risk, and the market risk of outages. In order to manage these risks, we may enter into fixed-price derivative or non-derivative contracts to hedge the variability in future cash flows from forecasted sales and purchases of energy, including:

- forward contracts, which commit us to purchase or sell energy commodities in the future,
- futures contracts, which are exchange-traded standardized commitments to purchase or sell a commodity or financial instrument, or to make a cash settlement, at a specific price and future date,
- swap agreements, which require payments to or from counterparties based upon the differential between two prices for a predetermined contractual (notional) quantity, and
- option contracts, which convey the right to buy or sell a commodity, financial instrument, or index at a predetermined price.

The objectives for entering into such hedges include:

- fixing the price for a portion of anticipated future electricity sales at a level that provides an acceptable return on our electric 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,
- managing our collateral requirements, and
- managing our exposure to interest rate risk and foreign currency exchange risks.

The portion of forecasted transactions hedged may vary based upon management's assessment of market, weather, operational, and other factors.

While some of the contracts we use to manage risk represent commodities or instruments for which prices are available from external sources, other commodities and certain contracts are not actively traded and are valued using other pricing sources and modeling techniques to determine expected future market prices, contract quantities, or both. We use our

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best estimates to determine the fair value of commodity and derivative contracts we hold and sell. These estimates consider various factors including closing exchange and over-the-counter price quotations, time value, volatility factors, and credit exposure. However, it is likely that future market prices could vary from those used in recording derivative assets and liabilities subject to mark-to-market accounting, and such variations could be material.

Power, gas, coal, and other commodity trading risks involve the potential decline in net income or financial condition due to adverse changes in market prices, whether arising from customer activities or proprietary positions taken by the Company. Price risk is monitored using VaR and EVaR.

VaR:

We measure the sensitivity of our mark-to-market energy contracts of our Global Commodities operation to potential changes in market prices using VaR. 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.

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

Total Wholesale VaR

For the year ended December 31,	**2008**	**2007**
	(In millions)	
99% Confidence Level, One-Day Holding Period		
Year end	**$ 19.7**	$ 20.4
Average	**26.1**	15.4
High	**38.0**	26.8
Low	**19.7**	8.2
95% Confidence Level, One-Day Holding Period		
Year end	**$ 15.0**	$ 15.5
Average	**19.9**	11.7
High	**28.9**	20.4
Low	**15.0**	6.2
95% Confidence Level, Ten-Day Holding Period		
Year end	**$ 47.5**	$ 49.1
Average	**62.8**	37.0
High	**91.5**	64.6
Low	**47.5**	19.7

The mark-to-market VaR during November and December 2008 was adjusted to eliminate the impact of a change in accounting treatment of coal positions that are expected to be part of the planned sale of our international commodities operation.

We experienced higher average VaR for the year ended December 31, 2008 compared to the year ended December 31, 2007, primarily due to a higher number of economic hedges of accrual positions, increased volatility of commodity market prices, and an increase in our trading activities discussed below. We discuss our mark-to-market results in more detail in the *Global Commodities* section.

The following table details our VaR for the trading portion of our wholesale marketing and risk management derivative assets and liabilities subject to mark-to-market accounting over a one-day holding period at a 99% confidence level for 2008 and 2007:

Wholesale Trading VaR

For the year ended December 31,	**2008**	2007
	(In millions)	
Average	**$ 17.8**	$ 11.0
High	**27.9**	17.4

Trading VaR was higher during 2008 as compared to 2007 due to increased price volatility and greater amount of risk the Global Commodities operation group managed during the year.

Our trading positions can be used to manage the commodity price risk of our customer supply activities and our generation facilities. We also engage in proprietary trading activities, though, as previously discussed, the Company is pursuing a new business strategy and proprietary trading will be sharply curtailed going forward. Trading activities are managed through daily VaR and stop loss limits and liquidity guidelines.

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Due to the inherent limitations of statistical measures such as VaR and the seasonality of changes in market prices, the VaR calculation may not reflect the full extent of our commodity price risk exposure. Additionally, because our VaR 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 VaR, and such changes could have a material impact on our financial results.

While VaR reflects the risk of loss under normal market conditions, stress testing captures the Company'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 VaR, stress testing is important in measuring and controlling risk. Stress testing enhances the understanding of the Company'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 the Company's senior management and to the lines of business to help them better measure and manage risks and to understand event risk-sensitive positions.

EVaR:

Where VaR is a measure of risk for our mark-to-market portfolios, 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 using a 5 year time horizon. At December 31, 2008, our EVaR was approximately $136 million, which represents a 31% decline from its level of $195 million in mid-September 2008, when we started reducing the risk of our Global Commodities portfolio. At January 31, 2009, EVaR has declined further to approximately $90 million. EVaR is a statistical risk measurement model subject to limitations similar to those of VaR.

Interest Rate Risk

We are exposed to changes in interest rates as a result of financing through our issuance of variable-rate and fixed-rate debt and certain related interest rate swaps. We may use derivative instruments to manage our interest rate risks.

In July 2004, to optimize the mix of fixed and floating-rate debt, we entered into interest rate swaps relating to $450.0 million of our long-term debt. These fair value hedges effectively convert our current fixed-rate debt to a floating-rate instrument tied to the three month London Inter-Bank Offered Rate. Including the $450.0 million in interest rate swaps, approximately 9% of our long-term debt is floating-rate.

We discuss our use of derivative instruments to manage our interest rate risk in more detail in *Note 13 to Consolidated Financial Statements*.

The following table provides information about our debt obligations that are sensitive to interest rate changes:

Principal Payments and Interest Rate Detail by Contractual Maturity Date

	2009	2010	2011	2012	2013	Thereafter	Total	Fair value at December 31, 2008
				(Dollars in millions)				
Long-term debt								
Variable-rate debt	$	$	$	$273.2	$ 10.0	$ 453.5	$ 736.7	$ 736.7
Average interest rate (A)	%	%	%	3.73%	1.39%	1.44%	2.24%	
Fixed-rate debt (B)	$2,566.5(C)	$56.9	$81.8	$624.1	$466.6	$ 3,640.5	$7,436.4	$ 6,290.3
Average interest rate	9.92%	5.68%	5.95%	6.82%	6.06%	6.64%	7.74%	

(A)

Interest on variable rate debt is included based on the forward curve for interest rates at December 31, 2008.

(B)
Fixed-rate debt includes $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.

(C)
Amount excludes $250.8 million of long-term debt that is periodically remarketed and could require us to repay the debt prior to maturity of which $25.0 million is classified as current portion of long-term debt in our Consolidated Balance Sheets and in Note 9 to Consolidated Financial Statements.

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Security Price Risk

We are exposed to price fluctuations in financial markets primarily through our pension plan assets, our nuclear decommissioning trust funds, and trust assets securing certain executive benefits. We are required by the NRC to maintain externally funded trusts for the costs of decommissioning our nuclear power plants. We discuss our nuclear decommissioning trust funds in more detail in *Note 1 to Consolidated Financial Statements*.

A hypothetical 10% decrease in security prices, excluding our pension plan assets, would result in an approximate $105.2 million reduction in the fair value of our financial investments that are classified as available-for-sale securities, excluding cash. In 2008, our actual loss on pension plan assets was $364.9 million due to significant declines in the markets in which plan assets are invested. We describe our funding requirements in more detail in the *Defined Benefits Plans and Funded Status* section. We describe our financial investments in more detail in *Note 4 to Consolidated Financial Statements*, and our pension plans in *Note 7 to Consolidated Financial Statements*.

Foreign Currency Risk

Our merchant energy business is exposed to the impact of foreign exchange rate fluctuations. This foreign currency risk arises from our activities in countries where we transact in currencies other than the U.S. dollar. In 2008, our exposure to foreign currency risk was not material. We manage our exposure to foreign currency exchange rate risk using a comprehensive foreign currency hedging program. While we cannot predict currency fluctuations, the impact of foreign currency exchange rate risk could be material, although we expect it will be minimal with respect to the Euro-dollar or British pound as we divest our international commodities operation. We will continue to have limited exposure to the Canadian dollar due to our gas and power operations.

Credit Risk

We are exposed to credit risk through our merchant energy business and BGE's operations. Credit risk is the loss that may result from counterparties' nonperformance and retail collections. We evaluate the credit risk of our Global Commodities operation and our retail activities separately as discussed below.

Wholesale Credit Risk

We measure wholesale credit risk as the replacement cost for open energy commodity and derivative transactions (both mark-to-market and accrual) adjusted for amounts owed to or due from counterparties for settled transactions. The replacement cost of open positions represents unrealized gains, net of any unrealized losses, where we have a legally enforceable right of setoff. We monitor and manage 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 December 31, 2008 and 2007, counterparties in the credit portfolio of our Global Commodities operation had the following public credit ratings:

At December 31,	**2008**	**2007**
Rating		
Investment Grade (1)	**52%**	44%
Non-Investment Grade	**15**	7
Not Rated	**33**	49

(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 $1.5 billion at December 31, 2008 compared to $2.1 billion at December 31, 2007. 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. Although not publicly rated, many of these 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 $883.7 million or 60% of the exposure to unrated counterparties was rated investment grade equivalent at December 31, 2008 and approximately $682.9 million or 33% was rated investment grade equivalent at December 31, 2007. The following table provides the breakdown of the credit quality of our wholesale credit portfolio based on our internal credit ratings.

At December 31,	2008	2007
Investment Grade Equivalent	**74%**	62%
Non-Investment Grade Equivalent	**26**	38

Our total exposure, net of collateral, to counterparties across our entire wholesale portfolio is $4.5 billion as of December 31, 2008. The top ten counterparties account for approximately 32% 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

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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.

Our total exposure of $4.5 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 $1.7 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 under SFAS No. 133, 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 December 31, 2008:

Rating	Total Exposure Before Credit Collateral	Credit Collateral	Net Exposure	Number of Counterparties Greater than 10% of Net Exposure	Net Exposure of Counterparties Greater than 10% of Net Exposure
			(Dollars in millions)		
Investment grade	$1,595	$ 382	$ 1,213		$
Split rating	7		7		
Non-investment grade	255	53	202		
Internally rated investment grade	293	60	233		
Internally rated non-investment grade	96	11	85		
Total	$2,246	$ 506	$ 1,740		$

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 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.

Retail Credit Risk

We are exposed to retail credit risk through our competitive electricity and natural gas supply activities, which serve commercial and industrial companies, and through BGE's electricity and natural gas distribution operations. Retail credit risk results when customers default on their contractual obligations or fail to pay for service rendered. This risk represents the loss that may be incurred due to the nonpayment of customer accounts receivable balances, as well as the loss from the resale of energy previously committed to serve customers of our nonregulated retail businesses.

Retail credit risk is managed through established credit approval policies, monitoring customer exposures, and the use of credit mitigation measures such as letters of credit or prepayment arrangements. In addition, we have taken steps to augment our credit staff in response to current economic conditions.

Retail credit quality is dependent on the economy and the ability of our customers to manage through unfavorable economic cycles and other market changes. If the business environment were to be negatively affected by changes in economic or other market conditions, our retail credit risk may be adversely impacted.

Our retail credit portfolio is diversified with no significant company or industry concentrations. In 2008, reserve levels have been increased across our retail businesses due to indicators of deteriorating credit quality and macroeconomic slowdown.

BGE is subject to retail credit risk associated with both the delivery portion of a customer's bill as well as on the uncollectible expense or credit risk from the gas and/or electric commodity portion of the bills of those customers to whom BGE sells the gas and electric commodity. Although both BGE's delivery and commodity rates include some level of costs for uncollectible customer accounts receivable expenses, full recovery is not guaranteed and BGE is exposed to these potential losses and related carrying costs.

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Operational Risk

Operational risk is the risk associated with human error or a failure of our processes and systems, or external factors. We are exposed to many types of operational risks, including the risk of fraud by employees or outsiders, clerical and record-keeping errors, and computer systems malfunctions. In addition, we may also be subject to disruptions in our operating systems arising from events that are wholly or partially beyond our control, such as natural disasters, acts of terrorism, and computer viruses, which may give rise to losses in service to customers and/or monetary losses to us.

We own and operate a number of power generation facilities, which utilize a diverse mix of fuel sources to include coal, gas, oil, hydro, biomass, and nuclear. We are exposed to risk resulting from generating plants not being available to produce energy and the risks related to physical delivery of energy to meet our customers' needs. If one or more of our generating facilities is not able to produce electricity when required due to operational factors, we may have to forego sales opportunities or fulfill fixed-price sales commitments through the operation of other more costly generating facilities or through the purchase of energy in the wholesale market at higher prices. We purchase electricity from generating facilities we do not own. If one or more of those generating facilities were unable to produce electricity due to operational factors, we may be forced to purchase electricity in the wholesale market at higher prices. This could have a material adverse impact on our financial results.

Our nuclear plants produce electricity at a relatively low marginal cost. The Nine Mile Point facility and the Ginna facility sell 90% of their respective output under unit-contingent power purchase agreements (we have no obligation to provide power if the units are not available) to the previous owners. However, if an unplanned outage were to occur at Calvert Cliffs during periods when demand was high, we may have to purchase replacement power at potentially higher prices to meet our obligations, which could have a material adverse impact on our financial results.

We are exposed to the risk that available sources of supply may differ from the amount of power demanded by our customers under fixed-price load-serving contracts. During periods of high demand, our power supplies may be insufficient to serve our customers' needs and could require us to purchase additional energy at higher prices. Alternatively, during periods of low demand, our electricity supplies may exceed our customers' needs and could result in us selling that excess energy at lower prices. Either of those circumstances could have a negative impact on our financial results.

We are also exposed to variations in the prices and required volumes of natural gas, oil, and coal we burn at our power plants to generate electricity. Therefore, high commodity prices increase the impact of generator outages and variable load, but as long as the electricity and fuel prices move in tandem, we have limited exposure to changing commodity prices. During periods of high demand on our generation assets, our fuel supplies may be insufficient and could require us to procure additional fuel at higher prices. Alternatively, during periods of low demand on our generation assets, our fuel supplies may exceed our needs, and could result in us selling the excess fuels at lower prices. Either of these circumstances will have a negative impact on our financial results.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

The information required by this item with respect to market risk is set forth in *Item 7* of Part II of this Form 10-K under the heading *Risk Management*.

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Item 8. Financial Statements and Supplementary Data

REPORTS OF MANAGEMENT

Financial Statements

The management of Constellation Energy Group, Inc. and Baltimore Gas and Electric Company (the "Companies") is responsible for the information and representations in the Companies' financial statements. The Companies prepare the financial statements in accordance with accounting principles generally accepted in the United States of America based upon available facts and circumstances and management's best estimates and judgments of known conditions.

PricewaterhouseCoopers LLP, an independent registered public accounting firm, has audited the financial statements and expressed their opinion on them. They performed their audit in accordance with the standards of the Public Company Accounting Oversight Board (United States).

The Audit Committee of the Board of Directors, which consists of four independent Directors, meets periodically with management, internal auditors, and PricewaterhouseCoopers LLP to review the activities of each in discharging their responsibilities. The internal audit staff and PricewaterhouseCoopers LLP have free access to the Audit Committee.

Management's Report on Internal Control Over Financial Reporting Constellation Energy Group, Inc.

The management of Constellation Energy Group, Inc. (Constellation Energy), under the direction of its principal executive officer and principal financial officer, is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Exchange Act Rule 13a-15(f).

Constellation Energy's system of internal control over financial reporting is designed to provide reasonable assurance to Constellation Energy's management and Board of Directors regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles in the United States of America.

The management of Constellation Energy conducted an evaluation of the effectiveness of Constellation Energy's internal control over financial reporting using the framework in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). As noted in the COSO framework, an internal control system, no matter how well conceived and operated, can provide only reasonable-not absolute-assurance to management and the Board of Directors regarding achievement of an entity's financial reporting objectives. Based upon the evaluation under this framework, management concluded that Constellation Energy's internal control over financial reporting was effective as of December 31, 2008.

PricewaterhouseCoopers LLP, an independent registered public accounting firm, has audited the effectiveness of Constellation Energy's internal control over financial reporting as of December 31, 2008, as stated in their report on the next page.

Mayo A. Shattuck III	Jonathan W. Thayer
Chairman of the Board, President and Chief Executive Officer	*Senior Vice President and Chief Financial Officer*

Management's Report on Internal Control Over Financial Reporting Baltimore Gas and Electric Company

The management of Baltimore Gas and Electric Company (BGE), under the direction of its principal executive officer and principal financial officer, is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Exchange Act Rule 13a-15(f).

BGE's system of internal control over financial reporting is designed to provide reasonable assurance to BGE's management and Board of Directors regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles in the United States of America.

The management of BGE conducted an evaluation of the effectiveness of BGE's internal control over financial reporting using the framework in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). As noted in the COSO framework, an internal control system, no matter how well conceived and operated, can provide only reasonable-not absolute-assurance to management and the Board of Directors regarding achievement of an entity's financial reporting objectives. Based upon the evaluation under this framework, management concluded that BGE's internal control over financial reporting was effective as of December 31, 2008.

This annual report does not include an attestation report of BGE's independent registered public accounting firm regarding internal control over financial reporting. Management's report was not subject to attestation by BGE's independent registered public accounting firm pursuant to temporary rules of the Securities and Exchange Commission that permit BGE to provide only management's report in this annual report.

Kenneth W. DeFontes, Jr.	Kevin W. Hadlock
President and Chief Executive Officer	*Senior Vice President and Chief Financial Officer*

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REPORTS OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
Constellation Energy Group, Inc.

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a) (1) present fairly, in all material respects, the financial position of Constellation Energy Group, Inc. and its subsidiaries (the Company) at December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a) (2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control Over Financial Reporting appearing under Item 8. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards required that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

As discussed in *Note 1* to the consolidated financial statements, in 2008 the Company changed its method of accounting for the measurement of fair value and classifying certain collateral balances. As discussed in *Note 1* to the consolidated financial statements, in 2007 the Company changed its method of accounting for uncertain tax positions. As discussed in *Note 7* to the consolidated financial statements, in 2006 the Company changed its method of accounting for defined benefit pension and other postretirement plans.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

We have also previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Constellation Energy Group, Inc. and its subsidiaries as of December 31, 2006, 2005, and 2004, and the related consolidated statements of income (loss), cash flows, and common shareholders' equity and comprehensive income for the years ended December 31, 2005 and 2004 (none of which are presented herein); and we expressed unqualified opinions on those consolidated financial statements. In our opinion, the information set forth in the Summary of Operations and Summary of Financial Condition of Constellation Energy Group, Inc. and its subsidiaries included in the Selected Financial Data appearing under Item 6 for each of the five years in the period ended December 31, 2008, is fairly stated, in all material respects, in relation to the consolidated financial statements from which it has been derived.

PricewaterhouseCoopers LLP
Baltimore, Maryland

February 27, 2009

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To Board of Directors and Shareholder of Baltimore Gas and Electric Company

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a) (1) present fairly, in all material respects, the financial position of Baltimore Gas and Electric Company and its subsidiaries (the Company) at December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a) (2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in *Note 1* to the consolidated financial statements, in 2008 the Company changed its method of accounting for the measurement of fair value. As discussed in *Note 1* to the consolidated financial statements, in 2007 the Company changed its method of accounting for uncertain tax positions.

We have also previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Baltimore Gas and Electric Company and its subsidiaries as of December 31, 2006, 2005 and 2004, and the related consolidated statements of income and cash flows for the years ended December 31, 2005 and 2004 (none of which are presented herein); and we expressed unqualified opinions on those consolidated financial statements. In our opinion, the information set forth in the Summary of Operations and Summary of Financial Condition of Baltimore Gas and Electric Company and its subsidiaries included in the Selected Financial Data appearing under Item 6 for each of the five years in the period ended December 31, 2008, is fairly stated, in all material respects, in relation to the consolidated financial statements from which it has been derived.

PricewaterhouseCoopers LLP
Baltimore, Maryland
February 27, 2009

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CONSOLIDATED STATEMENTS OF INCOME (LOSS)

Constellation Energy Group, Inc. and Subsidiaries

Year Ended December 31,	2008	2007	2006
	(In millions, except per share amounts)		
Revenues			
Nonregulated revenues	**$ 16,134.0**	$ 17,794.6	$ 16,279.0
Regulated electric revenues	**2,679.5**	2,455.6	2,115.9
Regulated gas revenues	**1,004.8**	943.0	890.0
Total revenues	**19,818.3**	21,193.2	19,284.9
Expenses			
Fuel and purchased energy expenses	**15,521.3**	16,473.9	14,930.7
Operating expenses	**2,378.8**	2,447.4	2,165.8
Merger termination and strategic alternatives costs	**1,204.4**		18.3
Impairment losses and other costs	**741.8**	20.2	
Workforce reduction costs	**22.2**	2.3	28.2
Depreciation, depletion, and amortization	**583.2**	557.8	523.9
Accretion of asset retirement obligations	**68.4**	68.3	67.6
Taxes other than income taxes	**301.8**	288.9	290.7
Total expenses	**20,821.9**	19,858.8	18,025.2
Net Gain on Sales of Upstream Gas Assets	**25.5**		
Gain on Sale of Gas-Fired Plants			73.8
(Loss) Income from Operations	**(978.1)**	1,334.4	1,333.5
Gain on Sales of CEP LLC Equity		63.3	28.7
Other (Expense) Income	**(52.3)**	158.6	66.1
Fixed Charges			
Interest expense	**399.1**	311.8	329.2
Interest capitalized and allowance for borrowed funds used during construction	**(50.0)**	(19.4)	(13.7)
BGE preference stock dividends	**13.2**	13.2	13.2
Total fixed charges	**362.3**	305.6	328.7
(Loss) Income from Continuing Operations Before Income Taxes	**(1,392.7)**	1,250.7	1,099.6
Income Tax (Benefit) Expense	**(78.3)**	428.3	351.0
(Loss) Income from Continuing Operations	**(1,314.4)**	822.4	748.6
(Loss) Income from discontinued operations, net of income taxes of $1.5, and $107.7, respectively		(0.9)	187.8
Net (Loss) Income	**$ (1,314.4)**	$ 821.5	$ 936.4
(Loss) Earnings Applicable to Common Stock	**$ (1,314.4)**	$ 821.5	$ 936.4
Average Shares of Common Stock Outstanding Basic	**179.1**	180.2	179.4
Average Shares of Common Stock Outstanding Diluted	**179.1**	182.5	181.4
(Loss) Earnings Per Common Share from Continuing Operations Basic	**$ (7.34)**	$ 4.56	$ 4.17
(Loss) Income from discontinued operations		(0.01)	1.05

(Loss) Earnings Per Common Share Basic	**$**	**(7.34)**	$	4.55	$	5.22
(Loss) Earnings Per Common Share from Continuing Operations Diluted	**$**	**(7.34)**	$	4.51	$	4.12
(Loss) Income from discontinued operations				(0.01)		1.04
(Loss) Earnings Per Common Share Diluted	**$**	**(7.34)**	$	4.50	$	5.16
Dividends Declared Per Common Share	**$**	**1.91**	$	1.74	$	1.51

See Notes to Consolidated Financial Statements.

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CONSOLIDATED BALANCE SHEETS

Constellation Energy Group, Inc. and Subsidiaries

At December 31,	**2008**	**2007**
	(In millions)	
Assets		
Current Assets		
Cash and cash equivalents	**$ 202.2**	$ 1,095.9
Accounts receivable (net of allowance for uncollectibles of **$240.6** and $44.9, respectively)	**3,389.9**	4,289.5
Fuel stocks	**717.9**	591.3
Materials and supplies	**224.5**	207.5
Derivative assets	**1,465.0**	760.6
Unamortized energy contract assets	**81.3**	32.0
Restricted cash	**1,030.5**	41.9
Deferred income taxes	**268.0**	300.7
Other	**815.5**	366.2
Total current assets	**8,194.8**	7,685.6
Investments and Other Noncurrent Assets		
Nuclear decommissioning trust funds	**1,006.3**	1,330.8
Other investments	**421.0**	542.2
Regulatory assets (net)	**494.7**	576.2
Goodwill	**4.6**	261.3
Derivative assets	**851.8**	1,030.2
Unamortized energy contract assets	**173.1**	178.3
Other	**421.3**	370.6
Total investments and other noncurrent assets	**3,372.8**	4,289.6
Property, Plant and Equipment		
Nonregulated property, plant and equipment	**8,866.2**	8,087.0
Regulated property, plant and equipment	**6,419.4**	6,051.2
Nuclear fuel (net of amortization)	**443.0**	374.3
Accumulated depreciation	**(5,012.1)**	(4,745.4)
Net property, plant and equipment	**10,716.5**	9,767.1
Total Assets	**$ 22,284.1**	$ 21,742.3

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

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CONSOLIDATED BALANCE SHEETS

Constellation Energy Group, Inc. and Subsidiaries

At December 31,	2008	2007
	(In millions)	
Liabilities and Equity		
Current Liabilities		
Short-term borrowings	**$ 855.7**	$ 14.0
Current portion of long-term debt	**2,591.5**	380.6
Accounts payable and accrued liabilities	**2,370.1**	2,630.1
Customer deposits and collateral	**120.3**	146.6
Derivative liabilities	**1,241.8**	1,134.3
Unamortized energy contract liabilities	**393.5**	392.2
Accrued expenses	**373.1**	528.5
Other	**514.2**	427.5
Total current liabilities	**8,460.2**	5,653.8
Deferred Credits and Other Noncurrent Liabilities		
Deferred income taxes	**677.0**	1,588.5
Asset retirement obligations	**987.3**	917.6
Derivative liabilities	**1,115.0**	1,118.9
Unamortized energy contract liabilities	**906.4**	1,218.6
Defined benefit obligations	**1,354.3**	828.6
Deferred investment tax credits	**44.1**	50.5
Other	**249.6**	155.9
Total deferred credits and other noncurrent liabilities	**5,333.7**	5,878.6
Capitalization		
Long-term debt	**5,098.7**	4,660.5
Minority interests	**20.1**	19.2
BGE preference stock not subject to mandatory redemption	**190.0**	190.0
Common shareholders' equity	**3,181.4**	5,340.2
Total capitalization	**8,490.2**	10,209.9
Commitments, Guarantees, and Contingencies (see Note 12)		
Total Liabilities and Equity	**$ 22,284.1**	$ 21,742.3

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

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CONSOLIDATED STATEMENTS OF CASH FLOWS

Constellation Energy Group, Inc. and Subsidiaries

Year Ended December 31,	2008	2007	2006
		(In millions)	
Cash Flows From Operating Activities			
Net (loss) income	**$ (1,314.4)**	$ 821.5	$ 936.4
Adjustments to reconcile to net cash provided by operating activities			
Gain on sales of gas-fired plants and discontinued operations			(191.4)
Depreciation, depletion, and amortization	**583.2**	557.8	523.9
Amortization of nuclear fuel	**123.9**	114.3	99.5
Amortization of energy contracts	**(256.3)**	(222.9)	(105.2)
All other amortization	**40.5**	11.2	26.9
Accretion of asset retirement obligations	**68.4**	68.3	67.6
Deferred income taxes	**(122.8)**	226.2	128.0
Investment tax credit adjustments	**(6.4)**	(6.7)	(6.9)
Deferred fuel costs	**52.0**	(248.0)	(348.5)
Defined benefit obligation expense	**99.6**	111.8	129.7
Defined benefit obligation payments	**(120.4)**	(165.4)	(89.2)
Merger termination and strategic alternatives costs	**541.8**		
Workforce reduction costs	**22.2**	2.3	28.2
Impairment losses and other costs	**741.8**	20.2	
Impairment losses on nuclear decommissioning trust assets	**165.0**	8.5	
Gains on sale of CEP LLC equity		(63.3)	(28.7)
Gains on sales of assets and investments	**(38.1)**		
Gains on termination of contracts	**(73.1)**		
Equity in earnings of affiliates less than dividends received	**6.3**	45.3	27.6
Derivative power sales contracts classified as financing activities under SFAS No. 149	**(107.2)**	32.2	2.6
Changes in working capital			
Accounts receivable, excluding margin	**606.7**	(664.2)	(237.7)
Derivative assets and liabilities, excluding collateral	**(757.9)**	(138.2)	(286.1)
Net collateral and margin	**(960.3)**	49.6	(630.6)
Materials, supplies, and fuel stocks	**(33.5)**	(66.4)	(267.2)
Other current assets	**(95.4)**	(18.5)	343.5
Accounts payable and accrued liabilities	**(225.8)**	448.8	380.5
Liability for unrecognized tax benefits	**79.7**	71.9	
Other current liabilities	**(238.1)**	(14.0)	19.9
Other	**(55.7)**	(54.5)	2.5
Net cash (used in) provided by operating activities	**(1,274.3)**	927.8	525.3
Cash Flows From Investing Activities			
Investments in property, plant and equipment	**(1,934.1)**	(1,295.7)	(962.9)
Asset acquisitions and business combinations, net of cash acquired	**(315.3)**	(347.5)	(137.6)
Investments in nuclear decommissioning trust fund securities	**(440.6)**	(659.5)	(492.5)
Proceeds from nuclear decommissioning trust fund securities	**421.9**	650.7	483.7
Net proceeds from sale of gas-fired plants and discontinued operations			1,630.7
Issuances of loans receivable		(19.0)	(65.4)
Proceeds from sales of investments and other assets	**446.3**	13.9	43.9
Contract and portfolio acquisitions		(474.2)	(2.3)
(Increase) decrease in restricted funds	**(942.8)**	(109.9)	7.7
Other	**21.7**	(45.3)	54.8
Net cash (used in) provided by investing activities	**(2,742.9)**	(2,286.5)	560.1
Cash Flows From Financing Activities			
Net issuance (maturity) of short-term borrowings	**813.7**	14.0	(0.7)
Proceeds from issuance of common stock	**17.6**	65.1	84.4
Proceeds from issuance of long-term debt	**3,211.4**	698.2	852.0
Proceeds from initial public offering of CEP			101.3

Common stock dividends paid	**(336.3)**	(306.0)	(264.0)
Reacquisition of common stock	**(16.2)**	(409.5)	
Proceeds from contract and portfolio acquisitions		847.8	221.3
Repayment of long-term debt	**(577.4)**	(745.3)	(609.1)
Derivative power sales contracts classified as financing activities under SFAS No. 149	**107.2**	(32.2)	(2.6)
Debt financing costs	**(104.8)**		
Other	**8.3**	33.4	8.1
Net cash provided by financing activities	**3,123.5**	165.5	390.7
Net (Decrease) Increase in Cash and Cash Equivalents	**(893.7)**	(1,193.2)	1,476.1
Cash and Cash Equivalents at Beginning of Year	**1,095.9**	2,289.1	813.0
Cash and Cash Equivalents at End of Year	**$ 202.2**	$ 1,095.9	$ 2,289.1
Other Cash Flow Information:			
Cash paid during the year for:			
Interest (net of amounts capitalized)	**$ 341.4**	$ 291.8	$ 304.7
Income taxes	**$ 119.2**	$ 282.4	$ 109.3

See Notes to Consolidated Financial Statements.

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

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CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDERS' EQUITY AND COMPREHENSIVE INCOME

Constellation Energy Group, Inc. and Subsidiaries

Year Ended December 31, 2008, 2007, and 2006	Common Stock Shares	Common Stock Amount	Retained Earnings	Accumulated Other Comprehensive Loss	Total Amount
	(Dollar amounts in millions, number of shares in thousands)				
Balance at December 31, 2005	178,301	$2,620.8	$ 2,810.2	$ (515.5)	$ 4,915.5
Comprehensive Income					
Net income			936.4		936.4
Other comprehensive income					
Hedging instruments:					
Reclassification of net losses on hedging instruments from OCI to net income, net of taxes of $375.6				620.8	620.8
Net unrealized loss on hedging instruments, net of taxes of $1,025.8				(1,683.4)	(1,683.4)
Available-for-sale securities:					
Reclassification of net gains on securities from OCI to net income, net of taxes of $0.1				(0.2)	(0.2)
Net unrealized gain on securities, net of taxes of $45.5				69.7	69.7
Minimum pension liability, net of taxes of $49.6				75.6	75.6
Net unrealized loss on foreign currency translation				(1.1)	(1.1)
Total Comprehensive Income			936.4	(918.6)	17.8
Effect of adoption of SFAS No. 158, net of taxes of $111.3				(169.5)	(169.5)
Common stock dividend declared ($1.51 per share)			(272.6)		(272.6)
Common stock issued and share-based awards	2,218	117.8			117.8
Other			0.3		0.3
Balance at December 31, 2006	180,519	2,738.6	3,474.3	(1,603.6)	4,609.3
Comprehensive Income					
Net income			821.5		821.5
Other comprehensive income					
Hedging instruments:					
Reclassification of net losses on hedging instruments from OCI to net income, net of taxes of $682.3				1,124.8	1,124.8
Net unrealized loss on hedging instruments, net of taxes of $408.2				(671.1)	(671.1)
Available-for-sale securities:					
Reclassification of net gains on securities from OCI to net income, net of taxes of $1.0				(1.6)	(1.6)
Net unrealized gain on securities, net of taxes of $25.5				26.5	26.5
Defined benefit plans:					
Net gain arising during period, net of taxes of $7.8				11.6	11.6
Amortization of net actuarial loss, prior service cost, and transition obligation included in net periodic benefit cost, net of taxes of $15.9				24.6	24.6
Net unrealized gain on foreign currency translation, net of taxes of $1.8				7.0	7.0
Other				(10.8)	(10.8)
Total Comprehensive Income			821.5	511.0	1,332.5
Effect of adoption of FIN 48			(7.3)		(7.3)
Common stock dividend declared ($1.74 per share)			(368.4)		(368.4)
Common stock issued and share-based awards	1,789	184.2			184.2
Common stock purchased	(1,847)	(159.5)			(159.5)
Common stock purchased and retired	(2,024)	(250.0)			(250.0)
Other			(0.6)		(0.6)
Balance at December 31, 2007	178,437	2,513.3	3,919.5	(1,092.6)	5,340.2

Comprehensive Loss					
Net loss			**(1,314.4)**		**(1,314.4)**
Other comprehensive loss					
Hedging instruments:					
Reclassification of net losses on hedging instruments from OCI to net income, net of taxes of $120.2				**200.6**	**200.6**
Net unrealized loss on hedging instruments, net of taxes of $561.6				**(875.3)**	**(875.3)**
Available-for-sale securities:					
Reclassification of net losses on securities from OCI to net income, net of taxes of $79.1				**81.7**	**81.7**
Net unrealized losses on securities, net of taxes of $189.8				**(197.5)**	**(197.5)**
Defined benefit plans:					
Prior service cost arising during period, net of taxes of $4.9				**(7.2)**	**(7.2)**
Net loss arising during period, net of taxes of $229.2				**(339.9)**	**(339.9)**
Amortization of net actuarial loss, prior service cost, and transition obligation included in net periodic benefit cost, net of taxes of $14.9				**21.3**	**21.3**
Net unrealized loss on foreign currency translation, net of taxes of $0.1				**(3.1)**	**(3.1)**
Other				**0.2**	**0.2**
Total Comprehensive Loss			**(1,314.4)**	**(1,119.2)**	**(2,433.6)**
Effect of adoption of SFAS No. 157			**0.9**		**0.9**
Common stock dividend declared ($1.91 per share)			**(341.3)**		**(341.3)**
Common stock issued and share-based awards *	**21,406**	**667.3**	**(35.8)**		**631.5**
Common stock purchased	**(200)**	**(16.1)**			**(16.1)**
Common stock purchased and retired	**(514)**				
Other			**(0.2)**		**(0.2)**
Balance at December 31, 2008	**199,129**	**$ 3,164.5**	**$ 2,228.7**	**$ (2,211.8)**	**$ 3,181.4**

** Includes 19,897.3 million shares issued to MidAmerican Energy Holdings Company. See Note 9 for more detail.*
See Notes to Consolidated Financial Statements.

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CONSOLIDATED STATEMENTS OF INCOME

Baltimore Gas and Electric Company and Subsidiaries

Year Ended December 31,	2008	2007	2006
		(In millions)	
Revenues			
Electric revenues	**$ 2,679.7**	$ 2,455.7	$ 2,115.9
Gas revenues	**1,024.0**	962.8	899.5
Total revenues	**3,703.7**	3,418.5	3,015.4
Expenses			
Operating expenses			
Electricity purchased for resale	**1,880.1**	1,500.4	1,167.8
Gas purchased for resale	**694.5**	639.8	581.5
Operations and maintenance	**537.8**	533.6	496.1
Workforce reduction costs	**6.4**		
Merger termination and strategic alternatives costs			4.7
Depreciation and amortization	**227.9**	234.2	227.5
Taxes other than income taxes	**174.5**	176.2	168.7
Total expenses	**3,521.2**	3,084.2	2,646.3
Income from Operations	**182.5**	334.3	369.1
Other Income	**29.6**	26.8	6.0
Fixed Charges			
Interest expense	**144.2**	127.9	104.6
Allowance for borrowed funds used during construction	**(4.3)**	(2.6)	(2.0)
Total fixed charges	**139.9**	125.3	102.6
Income Before Income Taxes	**72.2**	235.8	272.5
Income Taxes			
Current	**(18.2)**	(2.4)	(22.8)
Deferred	**40.2**	100.0	126.6
Investment tax credit adjustments	**(1.3)**	(1.6)	(1.6)
Total income taxes	**20.7**	96.0	102.2
Net Income	**51.5**	139.8	170.3
Preference Stock Dividends	**13.2**	13.2	13.2
Earnings Applicable to Common Stock	**$ 38.3**	$ 126.6	$ 157.1

See Notes to Consolidated Financial Statements.

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CONSOLIDATED BALANCE SHEETS

Baltimore Gas and Electric Company and Subsidiaries

At December 31,	**2008**	**2007**
	(In millions)	
Assets		
Current Assets		
Cash and cash equivalents	**$ 10.7**	$ 17.6
Accounts receivable (net of allowance for uncollectibles of **$33.3** and $20.3, respectively)	**327.0**	316.7
Accounts receivable, unbilled (net of allowance for uncollectibles of **$0.9** and $0.8, respectively)	**232.3**	209.5
Investment in cash pool, affiliated company	**148.8**	78.4
Accounts receivable, affiliated companies	**4.3**	4.2
Fuel stocks	**143.7**	98.8
Materials and supplies	**38.4**	42.7
Prepaid taxes other than income taxes	**51.0**	49.9
Regulatory assets (net)	**79.7**	74.9
Restricted cash	**23.7**	39.2
Other	**10.8**	7.4
Total current assets	**1,070.4**	939.3
Investments and Other Assets		
Regulatory assets (net)	**494.7**	576.2
Receivable, affiliated company	**161.1**	149.2
Other	**131.6**	148.1
Total investments and other assets	**787.4**	873.5
Utility Plant		
Plant in service		
Electric	**4,493.7**	4,244.4
Gas	**1,221.1**	1,181.7
Common	**476.3**	456.1
Total plant in service	**6,191.1**	5,882.2
Accumulated depreciation	**(2,191.0)**	(2,080.8)
Net plant in service	**4,000.1**	3,801.4
Construction work in progress	**225.7**	166.4
Plant held for future use	**2.6**	2.4
Net utility plant	**4,228.4**	3,970.2
Total Assets	**$ 6,086.2**	$ 5,783.0

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

At December 31,	**2008**	**2007**
	(In millions)	
Liabilities and Equity		
Current Liabilities		
Short-term borrowings	**$ 370.0**	$
Current portion of long-term debt	**90.0**	375.0
Accounts payable and accrued liabilities	**231.0**	182.4
Accounts payable and accrued liabilities, affiliated companies	**97.0**	164.5
Customer deposits and collateral	**72.3**	70.5
Current portion of deferred income taxes	**40.2**	44.1
Accrued taxes	**18.8**	34.4
Accrued expenses and other	**98.4**	96.3
Total current liabilities	**1,017.7**	967.2
Deferred Credits and Other Liabilities		
Deferred income taxes	**843.3**	785.6
Payable, affiliated company	**243.2**	243.7
Deferred investment tax credits	**10.6**	11.9
Other	**28.6**	33.6
Total deferred credits and other liabilities	**1,125.7**	1,074.8
Long-term Debt		
Rate stabilization bonds	**564.4**	623.2
First refunding mortgage bonds of BGE		119.7
Other long-term debt of BGE	**1,443.0**	1,214.5
6.20% deferrable interest subordinated debentures due October 15, 2043 to wholly owned BGE Capital Trust II relating to trust preferred securities	**257.7**	257.7
Long-term debt of nonregulated business	**25.0**	25.0
Unamortized discount and premium	**(2.4)**	(2.6)
Current portion of long-term debt	**(90.0)**	(375.0)
Total long-term debt	**2,197.7**	1,862.5
Minority Interest	**16.9**	16.8
Preference Stock Not Subject to Mandatory Redemption	**190.0**	190.0
Common Shareholder's Equity		
Common stock	**912.2**	912.2
Retained earnings	**625.4**	758.8
Accumulated other comprehensive income	**0.6**	0.7
Total common shareholder's equity	**1,538.2**	1,671.7
Commitments, Guarantees, and Contingencies (see Note 12)		
Total Liabilities and Equity	**$ 6,086.2**	$ 5,783.0

See Notes to Consolidated Financial Statements.

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CONSOLIDATED STATEMENTS OF CASH FLOWS

Baltimore Gas and Electric Company and Subsidiaries

Year Ended December 31,	2008	2007	2006
		(In millions)	
Cash Flows From Operating Activities			
Net income	**$ 51.5**	$ 139.8	$ 170.3
Adjustments to reconcile to net cash provided by operating activities			
Depreciation and amortization	**227.9**	234.2	227.5
Other amortization	**13.2**	12.5	13.6
Deferred income taxes	**40.2**	100.0	126.6
Investment tax credit adjustments	**(1.3)**	(1.6)	(1.7)
Deferred fuel costs	**52.0**	(248.0)	(348.5)
Defined benefit plan expenses	**30.6**	39.8	47.2
Allowance for equity funds used during construction	**(8.0)**	(4.9)	(3.7)
Workforce reduction costs	**6.4**		
Changes in			
Accounts receivable	**(33.1)**	(181.5)	135.8
Receivables, affiliated companies	**(0.1)**	(1.7)	(0.7)
Materials, supplies, and fuel stocks	**(40.6)**	9.6	(8.2)
Other current assets	**(4.5)**	25.9	(31.0)
Accounts payable and accrued liabilities	**48.6**	(4.9)	17.6
Accounts payable and accrued liabilities, affiliated companies	**(67.5)**	1.1	10.6
Other current liabilities	**(11.4)**	29.6	(0.9)
Long-term receivables and payables, affiliated companies	**(45.7)**	(42.0)	(70.1)
Other	**(29.1)**	(44.7)	(27.5)
Net cash provided by operating activities	**229.1**	63.2	256.9
Cash Flows From Investing Activities			
Utility construction expenditures (excluding equity portion of allowance for funds used during construction)	**(426.4)**	(376.4)	(320.6)
Change in cash pool at parent	**(70.4)**	(17.8)	(63.8)
Sales of investments and other assets	**12.9**	0.8	(0.4)
Decrease (increase) in restricted funds	**15.5**	(42.3)	10.3
Net cash used in investing activities	**(468.4)**	(435.7)	(374.5)
Cash Flows From Financing Activities			
Proceeds from issuance of short-term borrowings	**370.0**		
Proceeds from issuance of long-term debt	**400.0**	623.2	700.0
Repayment of long-term debt	**(350.0)**	(124.8)	(445.3)
Debt issuance costs	**(2.7)**		
Preference stock dividends paid	**(13.2)**	(13.2)	(13.2)
Distribution to parent	**(171.7)**	(106.0)	(128.1)
Net cash provided by financing activities	**232.4**	379.2	113.4
Net (Decrease) Increase in Cash and Cash Equivalents	**(6.9)**	6.7	(4.2)
Cash and Cash Equivalents at Beginning of Year	**17.6**	10.9	15.1
Cash and Cash Equivalents at End of Year	**$ 10.7**	$ 17.6	$ 10.9

Other Cash Flow Information:			
Cash paid (received) during the year for:			
Interest (net of amounts capitalized)	**$ 126.6**	$ 126.3	$ 87.2
Income taxes	**$ (5.1)**	$ (37.6)	$ 18.7

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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Notes to Consolidated Financial Statements

1 Significant Accounting Policies

Nature of Our Business

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

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

Consolidation Policy

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

Consolidation

We use consolidation for two types of entities:

- subsidiaries (other than variable interest entities) in which we own a majority of the voting stock, and
- variable interest entities (VIEs) for which we are the primary beneficiary. Financial Accounting Standards Board (FASB) Interpretation No. (FIN) 46R, *Consolidation of Variable Interest Entities*, requires us to use consolidation when we are the primary beneficiary of a VIE, which means that we have a controlling financial interest in a VIE. We discuss our investments in VIEs in more detail in *Note 4*.

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

The Equity Method

We usually use the equity method to report investments, corporate joint ventures, partnerships, and affiliated companies (including qualifying facilities and power projects) where we hold a 20% to 50% voting interest. Under the equity method, we report:

- our interest in the entity as an investment in our Consolidated Balance Sheets, and
- our percentage share of the earnings from the entity in our Consolidated Statements of Income (Loss).

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

The Cost Method

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

Sale of Subsidiary Stock

We may sell portions of our ownership interests through public offerings of a subsidiary's stock. Through 2008, we recorded any gains or losses on public offerings in our Consolidated Statements of Income (Loss), as a component of non-operating income. Beginning in 2009, we will apply the provisions of SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements, an amendment of ARB No. 51.* We discuss SFAS No. 160 in further detail later in this Note.

Regulation of Electric and Gas Business

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

When this happens, we and BGE must defer (include as an asset or liability in the Consolidated Balance Sheets and exclude from Consolidated Statements of Income (Loss)) certain regulated business expenses and income as regulatory assets and liabilities. We and BGE have recorded these regulatory assets and liabilities in the Consolidated Balance Sheets in accordance with Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulation.*

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

Use of Accounting Estimates

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

- our revenues and expenses in our Consolidated Statements of Income (Loss) during the reporting periods,

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- our assets and liabilities in our Consolidated Balance Sheets at the dates of the financial statements, and
- our disclosure of contingent assets and liabilities at the dates of the financial statements.

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

Reclassifications

We have reclassified certain prior-year amounts for comparative purposes for the following:

- Derivative assets and liabilities as of December 31, 2007 reflect the adoption of Staff Position FIN 39-1, *Amendment of FASB Interpretation No. 39*, on January 1, 2008. We discuss the adoption of Staff Position FIN 39-1 in more detail in the *Accounting Standards Adopted* section.
- We have separately presented "Restricted cash" that was previously reported within "Other current assets" on our and BGE's Consolidated Balance Sheets.
- 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.

Revenues

Sources of Revenue

We earn revenues from the following primary business activities:

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

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

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

Regulated Electric

BGE provides market-based standard offer electric service to residential and small commercial customers for the indefinite future and for large commercial and industrial customers for varying periods beyond June 30, 2004, depending on customer load. BGE charges these customers standard offer service (SOS) rates that are designed to recover BGE's wholesale power supply costs and include an administrative fee consisting of a shareholder return component and an incremental cost component. Pursuant to Senate Bill 1, the energy legislation enacted in Maryland in June 2006, BGE suspended collection of the shareholder return component of the administrative fee for residential SOS service beginning January 1, 2007 for a 10-year period. However, under an order issued by the Maryland PSC in May 2007, as of June 1, 2007, BGE reinstated collection of the residential return component of the SOS administration charge and began providing all residential electric customers a credit for the return component of the administrative charge. As part of the 2008 Maryland settlement agreement, which is discussed in more detail in *Note 2*, BGE resumed collection of the shareholder return portion of the residential standard offer service administrative charge from June 1, 2008 through May 31, 2010 without having to rebate it to all residential electric customers. BGE will cease collecting the residential shareholder return component again from June 1, 2010 through December 31, 2016. Senate Bill 1 imposed a 15% rate cap for BGE residential electric customers from July 1, 2006 until May 31, 2007 and gave customers the option to further delay paying full market rates until January 1, 2008.

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

Regulated Gas

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

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Selection of Accounting Treatment

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

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

We describe each of these accounting treatments below.

Accrual Accounting

Under accrual accounting, we record revenues in the period when we deliver energy commodities or products, render services, or settle contracts. We generally use accrual accounting to recognize revenues for our sales of electricity, gas, coal, and other commodities as part of our physical delivery activities. We enter into these sales transactions using a variety of instruments, including non-derivative agreements, derivatives that qualify for and are designated as normal purchases and normal sales (NPNS) of commodities that will be physically delivered, sales to BGE's customers under regulated service tariffs, and spot-market sales, including settlements with independent system operators. We discuss the NPNS election later in this Note under *Derivatives and Hedging Activities*.

However, we also use mark-to-market accounting rather than accrual accounting for recognizing revenue on our nonregulated retail gas customer supply activities and other physical commodity derivatives if we have not designated those contracts as NPNS.

We record accrual revenues from sales of products or services on a gross basis at the contract, tariff, or spot price because we are a principal to the transaction and otherwise meet the requirements of Emerging Issues Task Force (EITF) 03-11, *Reporting Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133, Accounting for Derivative Instruments and Hedging Activities, and Not Held for Trading Purposes,* and EITF 99-19, *Reporting Revenues Gross as a Principal versus Net as an Agent.*

Accrual revenues also include certain other gains and losses that relate to these activities or for which accrual accounting is required.

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

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

The following table summarizes the primary components of accrual revenues:

		Activity	
Component of Accrual Revenues	**Nonregulated Physical Energy Delivery**	**Regulated Electricity and Gas Sales**	**Other Nonregulated Products and Services**
Gross amounts receivable for sales of products or services based on contract, tariff, or spot price	X	X	X
Reclassification of net gains/losses on cash flow hedges from AOCI	X		
Ineffective portion of net gains/losses on cash flow hedges	X		

Amortization of acquired energy contract assets or liabilities	X	
Recovery or refund of deferred SOS and gas cost adjustment clause regulatory assets/liabilities		X

Mark-to-Market Accounting

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

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

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

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Equity in Earnings

We include equity in earnings from our investments in qualifying facilities and power projects, joint ventures, and Constellation Energy Partners LLC (CEP) in "Nonregulated revenues" in our Consolidated Statements of Income (Loss) in the period they are earned.

Fuel and Purchased Energy Expenses

Sources of Fuel and Purchased Energy Expenses

We incur fuel and purchased energy costs for:

- the fuel we use to generate electricity at our power plants,
- purchases of electricity from others, and
- purchases of natural gas, coal, and other fuel types that we resell.

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

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

Regulated Electric

BGE provides market-based standard offer electric service to residential and small commercial customers for the indefinite future and for large commercial and industrial customers for varying periods beyond June 30, 2004, depending on customer load. BGE charges these customers SOS rates that are designed to recover BGE's wholesale power supply costs and include an administrative fee consisting of a shareholder return component and an incremental cost component.

BGE defers the difference between certain of its actual costs related to the electric commodity and what it collects from customers under the commodity charge portion of SOS rates in a given period. BGE either bills or refunds its customers the difference in the future and includes amortization of the deferred amounts in fuel and purchased energy expense. Therefore, BGE's fuel and purchased energy expense approximates the amount of the related commodity charge included in revenues for the period, reflecting actual costs adjusted for the effects of the regulatory deferral mechanism.

Regulated Gas

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

BGE defers the difference between the portion of its actual gas commodity costs subject to the market-based rates incentive mechanism and what it collects from customers under the commodity charge in a given period. BGE either bills or refunds its customers the portion of this difference to which they are entitled through an adjustment to the price of gas service in future periods and includes amortization of the deferred amounts in fuel and purchased energy expense. Therefore, BGE's fuel and purchase energy expense approximates the amount of the related commodity charge included in revenues for the period, reflecting actual gas costs adjusted for the effects of the regulatory deferral mechanism.

Selection of Accounting Treatment

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

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

We describe each of these accounting treatments below.

Accrual Accounting

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

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

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

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

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

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

Mark-to-Market Accounting

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

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

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

Derivatives and Hedging Activities

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

- forward physical purchase and sales contracts, futures contracts,

financial swaps, and

option contracts.

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

Selection of Accounting Treatment

We account for derivative instruments and hedging activities in accordance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities, as amended and interpreted*. SFAS No. 133 permits several possible accounting treatments for derivatives that meet all of the applicable requirements of that standard. SFAS No. 133 requires mark-to-market 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 other elective accounting treatments must meet specific, restrictive criteria prescribed by SFAS No. 133, both at the time of designation and on an ongoing basis.

SFAS No. 133 provides for the following permissible accounting treatments for derivatives:

mark-to-market,

cash flow hedge,

fair value hedge, and

NPNS.

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

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

Mark-to-Market

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

- our 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.

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

Cash Flow Hedge

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

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

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

NPNS

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

Fair Value

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

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

The valuation adjustments we record include the following:

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

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

Balance Sheet Netting

We often transact with counterparties under master agreements and other arrangements that provide us with a right of setoff of amounts due to us and from us in the event of bankruptcy or default by the counterparty. We report these transactions on a net basis in our Consolidated Balance Sheets in accordance with FASB Interpretation No. 39, *Offsetting Amounts Related to Certain Contracts.* During 2007, the FASB issued Staff Position FIN 39-1, *Amendment of FASB Interpretation No. 39*, which was effective January 1, 2008. We discuss Staff Position FIN 39-1 in more detail later in *Note 1.*

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

Unamortized Energy Assets and Liabilities

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

Credit Risk

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

Electric and gas utilities, municipalities, cooperatives, generation owners, and energy marketers comprise the majority of counterparties underlying our assets from our wholesale marketing and risk management activities. We held cash collateral from these counterparties totaling $258.3 million as of December 31, 2008 and $269.9 million as of December 31, 2007. These amounts are included in "Customer deposits and collateral" in our Consolidated Balance Sheets.

Taxes

We summarize our income taxes in *Note 10*. BGE and our other subsidiaries record their allocated share of our consolidated federal income tax liability using the percentage complementary method specified in U.S. income tax regulations. As you read this section, it may be helpful to refer to *Note 10*.

Income Tax Expense

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

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

Tax Credits

We have deferred the investment tax credits associated with our regulated business and assets previously held by our regulated business in our Consolidated Balance Sheets. The investment tax credits are amortized evenly to income over the life of each property. We reduce current income tax expense in our Consolidated Statements of Income (Loss) for the investment tax

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credits and other tax credits associated with our nonregulated businesses.

Through December 31, 2007, we held certain investments in facilities that manufactured solid synthetic fuel produced from coal as defined under the Internal Revenue Code for which we claimed tax credits on our Federal income tax return. Because the federal tax credit for synthetic fuel produced from coal expired on December 31, 2007, these facilities ceased fuel production on that date. We recognized the tax benefit of these credits in our Consolidated Statements of Income (Loss) when we believe it is highly probable that the credits will be sustained.

Deferred Income Tax Assets and Liabilities

We must report some of our revenues and expenses differently for our financial statements than for income tax return purposes. The tax effects of the temporary differences in these items are reported as deferred income tax assets or liabilities in our Consolidated Balance Sheets. We measure the deferred income tax assets and liabilities using income tax rates that are currently in effect. During 2007, the State of Maryland increased its corporate income tax rate from 7% to 8.25%.

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

State and Local Taxes

State and local income taxes are included in "Income taxes" in our Consolidated Statements of Income (Loss).

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:

Year Ended December 31,	**2008**	**2007**	**2006**
		(In millions)	
Taxes other than income taxes included in revenues BGE	**$ 73.2**	$ 77.0	$ 74.0

Unrecognized Tax Benefits

We adopted FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes*, on January 1, 2007 (FIN 48). FIN 48 requires us to recognize in our financial statements the effects of uncertain tax positions if these positions meet a "more-likely-than-not" threshold. For those uncertain tax positions that we have recognized in our financial statements, we establish liabilities to reflect the portion of those positions we cannot conclude are "more-likely-than-not" to be realized upon ultimate settlement. These are referred to as liabilities for unrecognized tax benefits under FIN 48. We recognize interest and penalties related to unrecognized tax benefits in "Income tax expense" in our Consolidated Statements of Income (Loss).

The following table summarizes our total unrecognized tax benefits at January 1, 2007, the date of adoption of FIN 48:

At January 1, 2007	
Total liabilities reflected in our balance sheet for unrecognized tax benefits of $56.7 million less $12.1 million of interest and penalties	$ 44.6
Other unrecognized tax benefits not reflected in our balance sheet	59.4
Total unrecognized tax benefits	$ 104.0

The adoption of FIN 48 did not have a material impact on BGE's financial results.

Other unrecognized tax benefits relate to outstanding federal and state refund claims for which no tax benefit was previously provided in our financial statements because the claims do not meet the "more-likely-than-not" threshold. Included in this amount is $52.0 million of refund claims that have been disallowed by the applicable tax authorities for which we assess the probability of tax benefit recognition to be remote.

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

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 year. Diluted EPS reflects the potential dilution of common stock equivalent shares that could occur if securities or other contracts to issue common stock were exercised or converted into common stock.

Our dilutive common stock equivalent shares primarily consist of stock options and other stock-based compensation awards. The following table presents stock options that were not dilutive and were excluded from the computation of diluted EPS

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in each period, as well as the dilutive common stock equivalent shares as follows:

Year Ended December 31,	2008	2007	2006
	(In millions)		
Non-dilutive stock options	**2.6**		
Dilutive common stock equivalent shares	**5.5**	2.3	2.0

As a result of the Company incurring a loss for the year ended December 31, 2008, diluted 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 this feature of the Series A Preferred Stock in more detail in *Note 9*. These additional shares did not materially impact our earnings per share for 2008, but they will impact our earnings per share in future periods.

Stock-Based Compensation

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

SFAS No. 123R requires companies to recognize compensation expense for all equity-based compensation awards issued to employees that are expected to vest. Equity-based compensation awards include stock options, restricted stock, and any other share-based payments. Under SFAS No. 123R, we recognize compensation cost ratably or in tranches (depending if the award has cliff or graded vesting) over the period during which an employee is required to provide service in exchange for the award, which is typically a one to five-year period. We use a forfeiture assumption based on historical experience to estimate the number of awards that are expected to vest during the service period, and ultimately true-up the estimated expense to the actual expense associated with vested awards. We estimate the fair value of stock option awards on the date of grant using the Black-Scholes option-pricing model and we remeasure the fair value of liability awards each reporting period. We do not capitalize any portion of our stock-based compensation.

Cash and Cash Equivalents

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

Restricted Cash

As of December 31, 2008 and 2007, our restricted cash primarily represented the proceeds that we received on December 17, 2008 from issuance of the Series B Preferred Stock to EDF Group and related entities (EDF). These proceeds are restricted for payment of the 14% Senior Note that was held by MidAmerican. We used these proceeds to repay the Senior Note in January 2009. Our restricted cash also includes proceeds from financing for the acquisition, construction, installation and equipping of certain sewage and solid waste disposal facilities at our Brandon Shores coal-fired generating plant in Maryland.

As of December 31, 2008 and 2007, BGE's restricted cash primarily represented funds restricted for the repayment of the rate stabilization bonds. We discuss the rate stabilization bonds in more detail in *Note 9*.

Accounts Receivable and Allowance for Uncollectibles

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

Materials, Supplies, and Fuel Stocks

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

Financial Investments

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

SFAS No. 115, *Accounting for Certain Investments in Debt and Equity Securities,* applies particular requirements to some of our investments in debt and equity securities. We report those investments at fair value, and we use either specific identification or average cost to determine their cost for computing realized gains or losses.

Available-for-Sale Securities

We classify our investments in the nuclear decommissioning trust funds as available-for-sale securities. We describe the nuclear decommissioning trusts and the related asset retirement obligations later in this Note. In addition, we have investments in marketable equity securities and trust assets securing certain executive benefits that are classified as available-for-sale securities.

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

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

Long-Lived Assets

We evaluate certain assets that have long lives (for example, generating property and equipment and real estate) to determine if they are impaired when certain conditions exist. SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets,* provides the accounting requirements for impairments of long-lived assets and proved gas properties. We test our long-lived assets and proved gas properties for recoverability whenever events or changes in circumstances indicate that their carrying amount may not be recoverable.

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We determine if long-lived assets and proved gas properties are impaired by comparing their undiscounted expected future cash flows to their carrying amount in our accounting records. We record an impairment loss if the undiscounted expected future cash flows are less than the carrying amount of the asset. Cash flows for long-lived assets are determined at the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets and liabilities. Proven gas properties' cash flows are determined at the field level. Undiscounted expected future cash flows include risk-adjusted probable and possible reserves. We are also required to evaluate our equity-method and cost-method investments (for example, in partnerships that own power projects) for impairment. Accounting Principles Board (APB) No. 18, *The Equity Method of Accounting for Investments in Common Stock* (APB No. 18), provides the accounting requirements for these investments. The standard for determining whether an impairment must be recorded under APB No. 18 is whether the investment has experienced a loss in value that is considered an "other than a temporary" decline in value.

We evaluate unproved gas producing properties at least annually to determine if they are impaired under SFAS No. 19, *Financial Accounting and Reporting by Oil and Gas Producing Properties*. Impairment for unproved property occurs if there are no firm plans to continue drilling, lease expiration is at risk, or historical experience necessitates a valuation allowance.

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

Debt and Equity Securities

We evaluate our investments in debt and equity securities for impairment under FASB Staff Position (FSP) SFAS 115-1 and SFAS No. 124-1 (FSP SFAS No. 115-1 and 124-1), *The Meaning of Other-Than-Temporary Impairment and Its Application to Certain Investments.* FSP SFAS 115-1 and 124-1 require us to determine whether a decline in fair value of an investment below book value is other than temporary. If we determine that the decline in fair value is other than temporary, we write-down the cost basis of the investment to fair value as a new cost basis. Securities held in our nuclear decommissioning trust funds for which the market value is below book value must be written down to fair value because such declines in fair value are considered other than temporary.

Goodwill and Intangible Assets

Goodwill is the excess of the purchase price of an acquired business over the fair value of the net assets acquired. We account for goodwill and other intangibles under the provisions of SFAS No. 142, *Goodwill and Other Intangible Assets.* We do not amortize goodwill. SFAS No. 142 requires us to evaluate goodwill for impairment at least annually or more frequently if events and circumstances indicate the business might be impaired. Goodwill is impaired if the carrying value of the business exceeds fair value. Annually, we estimate the fair value of the businesses we have acquired using techniques similar to those used to estimate future cash flows for long-lived assets as previously discussed. If the estimated fair value of the business is less than its carrying value, an impairment loss is required to be recognized to the extent that the carrying value of goodwill is greater than its fair value. SFAS No. 142 also requires the amortization of intangible assets with finite lives. We discuss the changes in our goodwill and intangible assets in more detail in *Note 5*.

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

We report our property, plant and equipment at its original cost, unless impaired under the provisions of SFAS No. 144.

Original cost includes:

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

We own an undivided interest in the Keystone and Conemaugh electric generating plants in Western Pennsylvania, as well as in the transmission line that transports the plants' output to the joint owners' service territories. Our ownership interests in these plants are 20.99% in Keystone and 10.56% in Conemaugh. These ownership interests represented a net investment of $285.1 million at December 31, 2008 and $208.6 million at December 31, 2007. Each owner is responsible for financing its proportionate share of the plants' working funds. Working funds are used for operating expenses and capital expenditures. Operating expenses related to these plants are included in "Operating expenses" in our Consolidated Statements of Income (Loss). Capital costs related to these plants are included in "Nonregulated property, plant and equipment" in our Consolidated Balance Sheets.

The "Nonregulated property, plant and equipment" in our Consolidated Balance Sheets includes nonregulated generation construction work in progress of $1,230.8 million at December 31, 2008 and $329.6 million at December 31, 2007.

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

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

Our oil and gas exploration and production activities consist of working interests in gas producing fields. We account for these activities under the successful efforts method of accounting. Acquisition, development, and exploration costs are capitalized as permitted by SFAS No. 19. Costs of drilling exploratory wells are initially capitalized and later charged to

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expense if reserves are not discovered or deemed not to be commercially viable. Other exploratory costs are charged to expense when incurred.

There were no capitalized exploratory well costs at December 31, 2008 and $16.8 million at December 31, 2007, which do not include amounts that were capitalized and subsequently expensed within the same period. There were no material well costs capitalized at December 31, 2007 and 2006 that were reclassified in 2008 and 2007, respectively, to wells, facilities and equipment based on the determination of proved reserves.

There were $9.7 million of capitalized exploratory well costs charged to expense in 2008, with no material charges in 2007 and 2006. Additionally, there were $13.3 million of capitalized exploratory well costs sold during 2008 in conjunction with the sales of oil and natural gas properties in North Louisiana, South Texas, and Arkansas. There were no remaining capitalized exploratory well costs pending the determination of proved reserves at December 31, 2008. However, there were $12.9 million of such costs at December 31, 2007.

Depreciation and Depletion Expense

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

- the group straight-line method, approved by the Maryland PSC, applied to the average investment, adjusted for anticipated costs of removal less salvage, in classes of depreciable property based on an average rate of approximately 3.2% per year for our regulated business,
- the group straight-line method using rates averaging approximately 2.5% per year for our generating assets, or
- the units-of-production method over the remaining life of the estimated proved reserves at the field level for acquisition costs and over the remaining life of proved developed reserves at the field level for development costs. The estimates for gas reserves are based on internal calculations.

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

Asset	**Estimated Useful Lives**
Building and improvements	5 - 50 years
Office equipment and furniture	3 - 20 years
Transportation equipment	5 - 15 years
Computer software	3 - 10 years

Amortization Expense

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

Accretion Expense

SFAS No. 143, *Accounting for Asset Retirement Obligations,* provides the accounting requirements for recognizing an estimated liability for legal obligations associated with the retirement of tangible long-lived assets. FIN 47, *Accounting for Conditional Asset Retirement Obligations an Interpretation of FASB Statement No. 143,* clarifies that asset retirement obligations that are conditional upon a future event are subject to the provisions of SFAS No. 143. Our conditional asset retirement obligations relate primarily to asbestos removal at certain of our generating facilities.

At December 31, 2008, $964.4 million of our total asset retirement obligation of $987.3 million was associated with the decommissioning of our nuclear power plants Calvert Cliffs Nuclear Power Plant (Calvert Cliffs), Nine Mile Point Nuclear Station (Nine Mile Point) and R. E. Ginna Nuclear Power Plant (Ginna). The remainder of our asset retirement obligations is associated with our other generating facilities and certain other long-lived assets.

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

The increase in the capitalized cost is included in determining depreciation expense over the estimated useful lives of these assets. Since the fair value of the asset retirement obligations is determined using a present value approach, accretion of the liability due to the passage of time is recognized each period to "Accretion of asset retirement obligations" in our Consolidated Statements of Income (Loss) until the settlement of the liability. We record a gain or loss when the liability is settled after retirement for any difference between the accrued liability and actual costs. The change in our "Asset retirement obligations" liability during 2008 was as follows:

	(In millions)
Liability at January 1, 2008	$ 917.6
Liabilities incurred	1.7
Liabilities settled	(0.7)
Accretion expense	68.4
Revisions to cash flows	2.9
Other	(2.6)
Liability at December 31, 2008	$ 987.3

Nuclear Decommissioning

We are obligated to decommission our Calvert Cliffs, Nine Mile Point, and Ginna nuclear power plants after these plants cease operation in accordance with Nuclear Regulatory Commission (NRC) regulations and relevant state requirements.

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In March 2008, Constellation Energy, BGE, and a Constellation Energy affiliate entered into a settlement agreement with the State of Maryland, the Maryland PSC and certain State of Maryland officials which became effective on June 1, 2008. Pursuant to the terms of the settlement agreement, BGE customers will be relieved of the potential future liability for decommissioning Constellation Energy's Calvert Cliffs Unit 1 and Unit 2, scheduled to occur no earlier than 2034 and 2036, respectively. BGE will continue to collect the $18.7 million annual nuclear decommissioning charge from all electric customers through 2016 and continue to rebate this amount to residential electric customers, as previously required by Senate Bill 1, which had been enacted in June 2006. We discuss the Maryland settlement agreement in more detail in *Note 2*.

The following is a summary of our asset retirement obligations associated with the decommissioning of these plants:

At December 31,	**2008**	**2007**
	(in millions)	
Calvert Cliffs	**$ 333.4**	$ 309.5
Nine Mile Point	**368.4**	341.9
Ginna	**262.6**	245.9
Total	**$ 964.4**	$ 897.3

In accordance with NRC regulations, we maintain external decommissioning trusts to fund the costs expected to be incurred to decommission our nuclear plants. Our nuclear decommissioning trust funds and the investment earnings thereon are restricted to meeting the costs of decommissioning the plants in accordance with NRC regulations and relevant state requirements. We develop our decommissioning trust fund strategy based on estimates of the costs to perform the decommissioning and the timing of incurring those costs. When developing our estimates of future fund earnings, we consider our asset allocation investment strategy, rates of return earned historically, and current market conditions. Investments by nuclear decommissioning trust funds are guided by the "prudent man" investment principle. The funds are prohibited from investing directly in Constellation Energy or its affiliates and any other entity owning a nuclear power plant.

The assets in the trusts are reported in "Nuclear decommissioning trust funds" in our Consolidated Balance Sheets. We classify the investments in the nuclear decommissioning trust funds as available-for-sale securities, and we report these investments at fair value in our Consolidated Balance Sheets as previously discussed in this Note.

The external trust fund balances were as follows:

At December 31,	**2008**	**2007**
	(in millions)	
Calvert Cliffs	**$ 346.9**	$ 457.4
Nine Mile Point	**460.3**	610.2
Ginna	**199.1**	263.2
Total	**$ 1,006.3**	$ 1,330.8

The $324.5 million decrease in the value of the external trust fund balances is comprised of impairment charges of $165.0 million, recorded in "Other (Expense) Income," unrealized losses of $207.0 million, recorded in "Accumulated other comprehensive loss," partially offset by contributions of $18.7 million and income of $28.8 million.

Our contributions to the nuclear decommissioning trust funds for Calvert Cliffs were $18.7 million for 2008, $8.8 million for 2007, and $8.8 million for 2006. No contributions were made to the trust funds for Nine Mile Point and Ginna during the years ended December 31, 2008, 2007, and 2006.

Nuclear Fuel

We amortize the cost of nuclear fuel, including the quarterly fees we pay to the Department of Energy (DOE) for the future disposal of spent nuclear fuel, based on the energy produced over the life of the fuel. These fees are based on the kilowatt-hours of electricity sold. We report the amortization expense for nuclear fuel in "Fuel and purchased energy expenses" in our Consolidated Statements of Income (Loss).

Capitalized Interest and Allowance for Funds Used During Construction

Capitalized Interest

Our nonregulated businesses capitalize interest costs under SFAS No. 34, *Capitalizing Interest Costs,* for costs incurred to finance our power plant construction projects, real estate developed for internal use, and other capital projects.

Allowance for Funds Used During Construction (AFC)

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

The AFC rates are 9.4% for electric distribution plant, 8.8% for electric transmission plant, 8.5% for gas plant, and 9.1% for common plant. BGE compounds AFC annually.

Long-Term Debt and Credit Facilities

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

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

Accounting Standards Issued

SFAS No. 141 Revised

In December 2007, the FASB issued SFAS No. 141 Revised (SFAS No. 141R), *Business Combinations*. SFAS No. 141R revises SFAS 141, *Business Combinations.* SFAS No. 141R requires the purchaser of a business to determine the fair value of the consideration exchanged as of the acquisition date (i.e., the date the acquirer obtains control). Previously, an acquisition was valued as of the date the parties agree upon the terms of the transaction. SFAS No. 141R also modifies, among other things, the accounting for direct costs associated with an acquisition, contingencies acquired, and contingent consideration. We will apply SFAS No. 141R for all future business combinations that close after January 1, 2009.

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. SFAS No. 160 requires that companies:

- present noncontrolling 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.

SFAS No. 160 must be applied prospectively as of January 1, 2009, except that existing noncontrolling interests must be reclassified retrospectively for all periods presented.

The adoption of SFAS No. 160 will affect how we present and disclose noncontrolling interests in our financial statements and how we account for future changes in ownership interests in subsidiaries. Specifically, we will:

- reclassify approximately $20 million of noncontrolling interests to a separate line within common shareholders' equity, and
- record the income attributable to our noncontrolling interests in a separate line on the Consolidated Statement of Income (Loss) after net income in order to arrive at net income available to common stock.

Upon closing of our Investment Agreement with EDF, under SFAS No. 160, we anticipate that we will deconsolidate our subsidiary that owns our nuclear generation and operation business, record our ownership interest in this entity at fair value, and recognize a material gain on both the portion of the subsidiary sold to EDF and our retained interest.

SFAS No. 161

In March 2008, the FASB issued SFAS No. 161, *Disclosures About Derivative Instruments and Hedging Activities*. SFAS No. 161 is effective beginning January 1, 2009 and requires entities to provide expanded disclosure about derivative instruments and hedging activities regarding: (1) the ways in which an entity uses derivatives, (2) the accounting for derivatives and hedging activities, and (3) the impact that derivatives have (or could have) on an entity's financial position, financial performance, and cash flows. SFAS No. 161 requires expanded disclosures, but does not change the accounting for derivatives. We do not expect the adoption of this standard to have a material impact on our, or BGE's, financial results because it only provides for additional disclosure.

FSP SFAS No. 132R-1

In December 2008, the FASB issued Staff Position (FSP) No. 132R-1, *Employers' Disclosures about Postretirement Benefit Plan Assets*, which amends SFAS No. 132R, *Employers' Disclosures about Pensions and Other Postretirement Benefits.* The FSP expands the disclosures set forth in SFAS No. 132R by adding required disclosures about: (1) how investment allocation decisions are made by management, (2) major categories of plan assets, and (3) significant concentrations of risk. In addition, the FSP requires disclosure of information about the valuation of plan assets similar to that required under SFAS No. 157, *Fair Value Measurements*. Those disclosures include: (1) the level within the fair value hierarchy in which the fair value measurements of plan assets fall, (2) information about the inputs and valuation techniques used to measure the fair value of plan assets, and (3) a reconciliation of the beginning and ending balances of plan assets valued using significant unobservable inputs. The disclosures about plan assets required by the FSP must be provided for years ending after December 15, 2009. We are currently evaluating the impact of this FSP, but, because it only provides for additional disclosure, we do not expect the adoption of this standard to have a material impact on our, or BGE's, financial results.

Accounting Standards Adopted

FSP FIN 39-1

In April 2007, the FASB issued FSP FIN 39-1, *Amendment of FASB Interpretation No. 39*. As amended, FIN 39, *Offsetting of Amounts Related to Certain Contracts*, requires an entity to report all derivatives recorded at fair value net of any associated fair value cash collateral with the same counterparty under a master netting arrangement. Therefore, effective January 1, 2008, we reported all derivatives recorded at fair value net of the associated fair value cash collateral. We applied the provisions of FSP FIN 39-1 by adjusting all financial statement periods

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presented, which reduced total assets at December 31, 2007 by $203.4 million. We present the fair value cash collateral that has been offset against our net derivative positions as part of our adoption of SFAS No. 157 in *Note 13*.

SFAS No. 157

Effective January 1, 2008, we adopted SFAS No. 157, *Fair Value Measurements*, which defines fair value, establishes a framework for measuring fair value, and requires certain disclosures about fair value measurements.

SFAS No. 157 does not require any new fair value measurements but instead applies when other accounting pronouncements require or permit fair value measurements. SFAS No. 157 defines fair value as 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). Unless otherwise noted, when we use the term "fair value" throughout the footnotes related to 2008 we are referring to fair value as defined by SFAS No. 157.

We applied the provisions of SFAS No. 157 prospectively as of January 1, 2008. We will apply the provisions of SFAS No. 157 for nonfinancial assets and liabilities effective January 1, 2009. Prior to the adoption of SFAS No. 157, we determined fair value for derivative liabilities for which prices are not available from external sources by discounting the expected cash flows from the contracts using a risk-free discount rate. We did not reflect our own credit risk in determining fair value for these liabilities. SFAS No. 157 requires us to record all liabilities measured at fair value by including the effect of our own credit risk. Accordingly, we applied a credit-spread adjustment in order to reflect our own credit risk in determining fair value for these liabilities, which reduced the recorded amount of these liabilities as of the date of adoption. As a result, during the first quarter of 2008 we recorded a pre-tax reduction in "Accumulated other comprehensive loss" totaling $10 million for the portion related to cash-flow hedges and a pre-tax gain in earnings totaling $3 million for the remainder of our derivative liabilities. All other impacts of adoption were immaterial.

We discuss SFAS No. 157 in more detail including the required disclosures in *Note 13*.

FSP SFAS No. 157-3

In October 2008, the FASB issued FSP SFAS No. 157-3, *Determining the Fair Value of a Financial Asset When the Market for That Asset is Not Active*. This FSP does not change the guidance contained in SFAS No. 157; rather, it clarifies the application of SFAS No. 157 in a market that is not active. This FSP was effective for the period ended September 30, 2008, and the adoption of this FSP did not have an effect on our financial results.

FSP SFAS No. 140-4 and FIN 46R-8

In December 2008, the FASB issued FSP SFAS No. 140-4 and FIN 46(R)-8, *Disclosures About Transfers of Financial Assets and Interests in Variable Interest Entities,* which requires public entities to make additional disclosures about transfers of financial assets and involvement with variable interest entities. This FSP does not change the accounting for transfers of financial assets or variable interest entities; rather, it only requires additional disclosures related to such items. We reflected the provisions of the FSP in *Note 4*.

2 Other Events

2008 Events

	Pre-Tax	After-Tax
	(In millions)	
Merger termination and strategic alternatives costs	$ (1,204.4)	$ (1,204.4)
Impairment losses and other costs	(741.8)	(470.7)
Workforce reduction costs	(22.2)	(13.4)
Emissions allowances write-down	(46.7)	(28.7)
Net gain on sales of upstream gas assets	25.5	16.0
Gain on sale of dry bulk vessel	29.0	18.9
Maryland settlement credit (after-tax amount reflects the effective tax rate impact on BGE)	(189.1)	(110.5)
Impairment of nuclear decommissioning trust assets	(165.0)	(82.0)
Total other items	$ (2,314.7)	$ (1,874.8)

Merger Termination and Strategic Alternatives Costs

We incurred costs during 2008 related to the terminated merger agreement with MidAmerican, the conversion of Series A Preferred Stock, the execution of the Investment Agreement and related agreements with EDF, and our pursuit of other strategic alternatives. These costs totaled $1,204.4 million pre-tax. We did not record a tax benefit for any of these costs in our Consolidated Statement of Income (Loss) in 2008.

A significant portion of these costs was incurred pursuant to the termination of the merger agreement with MidAmerican and the conversion of the Series A Preferred Stock. Specifically, Constellation Energy incurred the following charges:

- $175 million merger termination fee,
- approximately $945 million for settling the conversion of the Series A Preferred Stock, which included a cash payment of $418 million and issuance of approximately 19.9 million shares of our common stock,
- approximately $15 million for the remaining unamortized portion of the premium paid as part of executing an agreement with MidAmerican in November 2008 that provided us the option to sell certain generating plants to MidAmerican for aggregate proceeds of $350 million. This agreement was terminated as part of the termination of our merger agreement with MidAmerican, and
- approximately $70 million in other costs associated with the MidAmerican transaction and other strategic alternatives explored consisting primarily of external legal, accounting and consulting fees.

The above amounts do not include $150 million of cash received from EDF in conjunction with the Investment Agreement entered into on December 17, 2008. We will record this $150 million as additional purchase price for EDF's purchase of a 49.99% membership interest in our nuclear generation and operation business. This amount has been deferred on our Consolidated Balance Sheets pending closing of the sale.

BGE recorded $16 million as its allocable portion of these costs through November 30, 2008 when the merger with MidAmerican was still pending. However, in light of the EDF transaction involving an investment in our nonregulated nuclear generation and operation business rather than a merger with Constellation Energy, BGE has not been allocated any further costs effective in December 2008 and all of the previously allocated costs recorded by BGE have been allocated to the merchant energy segment.

Impairment Losses and Other Costs

Impairment Evaluations

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

In addition, Statement of Financial Accounting Standards (SFAS) No. 142, *Goodwill and Other Intangible Assets* requires that goodwill be evaluated for impairment on an annual basis regardless of whether any triggering events have occurred. Our accounting policy is to perform an annual goodwill impairment review in the third quarter of each year.

During the third quarter of 2008, the following triggering events resulted in the need for us to perform impairment analyses:

- we announced a strategic initiative to sell our upstream gas assets subject to market conditions,
- there was a significant decline in the availability of credit in the markets,
- there was a significant decline in the overall stock market and, in particular, our stock price,
- we signed a definitive merger agreement with MidAmerican, which was subsequently terminated, and
- commodity prices declined substantially.

As a result of these evaluations, we recorded impairments of our upstream gas properties, goodwill, and certain investments in debt and equity securities. Additionally, in the fourth quarter of 2008, there were continued declines in commodity prices and the overall stock market. This led to further impairment of our upstream gas properties, and certain investments in debt and equity securities. We describe the impairment evaluations we performed in the following sections.

Long-Lived Assets

We evaluate potential impairment of long-lived assets classified as held for use under SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, which provides that an impairment loss shall be recognized if the carrying amount of such assets is not recoverable. The carrying amount of an asset held for use is not recoverable if it exceeds the total undiscounted future cash flows expected to result from the use and eventual disposition of the asset.

This evaluation requires us to estimate uncertain future cash flows. In order to estimate future cash flows, we consider historical cash flows and changes in the market environment and other factors that may affect future cash flows. The assumptions we use are consistent with forecasts that we make for other purposes (for example, in preparing our other earnings forecasts) or have been adjusted to reflect relevant subsequent changes. If we are considering alternative courses of action (such as the potential sale of an asset), we probability-weight the alternative courses of action to estimate the expected cash flows.

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

Upstream Gas Properties

During 2008, we performed impairment analyses for our upstream gas properties as a result of the following triggering events:

- we announced our intent to sell our upstream gas assets, and
- there were significant decreases in natural gas prices and oil prices in both the third and fourth quarters of 2008.

We evaluate proved properties under SFAS No. 144. We evaluate unproved property under SFAS No. 19, *Financial Accounting and Reporting by Oil and Gas Producing Properties*. Unproved property is impaired if there are no firm plans to continue drilling, lease expiration is at risk, or historical experience necessitates a valuation allowance. To the extent that unproved property is part of an asset that contains proved property, the accounting guidance under SFAS No. 144 applies for evaluating impairment.

We have begun the process necessary to sell our upstream gas properties, and, while we sold some of these properties in the fourth quarter of 2008, we have not yet obtained the formal approval of our Board of Directors for the sale of our other remaining properties. This approval is required to commit to a plan for sale. As a result, we continue to classify these properties as held for use as of December 31, 2008. Accordingly, our impairment evaluation consisted of estimating expected undiscounted cash flows under various scenarios as discussed below and comparing those amounts to the carrying value.

We evaluated our upstream gas portfolio for impairment at the individual property level, which is the lowest level of identifiable cash flows, since each property has separate financial statements identifying and capturing the related cash flows. We evaluated a combination of cash flows from operations scenarios for the remaining period for which we expect to hold these properties as well as estimates of proceeds from each property's ultimate disposal. The primary inputs to our estimates of cash flows from operations were reserve estimates and natural gas and oil prices based upon forward curves and modeled data for unobservable periods. The primary inputs to our estimate of proceeds from disposal were a combination of external market bids, internal models and reserve reports, and information from external advisors assisting in the sale of these assets. We maximized the use of market information to the extent it was available. We evaluated several possible courses of action and timing, and we probability-weighted the cash flows associated with each of these scenarios based upon our best estimates of the expected outcome and timing in order to arrive at each property's expected future cash flows.

Our evaluation indicated that estimated cash flows were less than the carrying value of three of our seven upstream gas properties at September 30, 2008. At December 31, 2008, our evaluation indicated that estimated cash flows were less than the carrying value for two additional properties and for one property in which that property's estimated cash flows were less than its post-impairment carrying value at September 30, 2008 as well. The primary factors leading to the declines in expected cash flows were the decrease in market prices for natural gas and oil during the third and fourth quarters of 2008 combined with our expectation that we would sell these properties rather than hold them for their full useful lives.

As a result, we recorded the following pre-tax impairment charges:

Asset Groups	**At September 30, 2008**	**At December 31, 2008**
	(In millions)	
Interest in proved and unproved natural gas and crude oil reserves in south Texas	**$ 62.6**	**$**

Interest in proved natural gas reserves in the Rocky Mountains		**73.2**		
Interest in proved and unproved natural gas reserves in the Offshore-Gulf of Mexico		**7.1**		**3.8**
Interest in proved and unproved crude oil and natural gas reserves in eastern Oklahoma				**30.0**
Interest in proved and unproved natural gas reserves in central Oklahoma				**153.2**
Total impairment charges	**$**	**142.9**	**$**	**187.0**

We recorded these impairment charges in the "Impairment losses and other costs" line in our Consolidated Statements of Income (Loss), and they are reported in our merchant energy business results.

Generating Plants

We evaluated the impact of the events that occurred in 2008 on the recoverability of our generating plants. Based upon our consideration of these events and the status of the generating plant's activities, we determined that our generating plants are not impaired as of September 30, 2008 and December 31, 2008.

Debt and Equity Securities and Investments

We evaluated certain of our investments in debt and equity securities (both equity-method and cost-method investments) in light of recent declines in market prices during the third and fourth quarters of 2008. The investments we evaluated include our investment in CEP, other marketable securities, our nuclear decommissioning trust fund assets, and our investment in UniStar Nuclear Energy (UNE). We record an impairment if an investment has experienced a decline in fair value to a level less than our carrying value and the decline is "other than temporary." We do not record an impairment if the decline in value is temporary and we have the ability and intent to hold the investment until its value recovers.

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

The fair value of our investment in CEP fell below carrying value at the end of August, and continued to decline through the end of 2008. As of September 30, 2008, the fair value of our investment in CEP based upon its closing unit price was $73 million, which was lower than its carrying value of $128 million. As of December 31, 2008, the fair value of our investment in CEP based upon its closing unit price was $17 million, which was lower than its carrying value at December 31, 2008 of $87 million.

While CEP's estimate of net asset value exceeded our carrying value, the decline in fair value of our investment in CEP reflects a number of other factors, including:

- turmoil and tightening in the financial and credit markets in the United States,
- substantial 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 at both September 30, 2008 and December 31, 2008, we determined that the declines in the value of our investment at both dates were other than temporary. Therefore, we recorded a $54.7 million pre-tax impairment charge at September 30, 2008 and an additional $69.7 million pre-tax impairment charge at December 31, 2008 to write-down our investment to fair value. We recorded these charges in "Impairment losses and other costs" in our Consolidated Statements of Income (Loss). 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.

As a result of significant declines in the stock market during 2008, the fair values of certain of our marketable securities and many of the securities held in our nuclear decommissioning trust fund declined below book value. As a result, we recorded impairment charges of $31.0 million and $122.0 million pre-tax at September 30, 2008 and December 31, 2008, respectively, for our nuclear decommissioning trust fund investments in the "Other (expense) income" line in our Consolidated Statements of Income (Loss). We had previously recorded impairment charges for our nuclear decommissioning trust fund at both March 31, 2008 and June 30, 2008, totaling $12.0 million pre-tax. We also recorded an impairment charge of $7.0 million pre-tax for certain of our other marketable securities in the fourth quarter of 2008. In addition, we recorded other changes in the fair value of our nuclear decommissioning trust fund assets that are not impaired in other comprehensive income. We discuss the assets within our nuclear decommissioning trust funds in more detail in *Note 4*.

We also evaluated the impact of the events that occurred in 2008 on the recoverability of our investment in UNE. Based upon our consideration of these events and the status of UNE's activities, we determined that our investment in UNE is not impaired as of December 31, 2008.

The estimates we utilize in evaluating impairment of our debt and equity 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.

Goodwill

Goodwill is the excess of the purchase price of an acquired business over the fair value of the net assets acquired. We account for goodwill and other intangibles under the provisions of SFAS No. 142, which requires us to evaluate goodwill for impairment at least annually or more frequently if events and circumstances indicate the business might be impaired. Goodwill is impaired if the carrying value of the business exceeds fair value. Annually, in the third quarter of each year, we evaluate goodwill for impairment.

The primary judgment affecting our impairment evaluation is the requirement to estimate fair value of the reporting units to which the goodwill relates. We evaluate impairment at the reportable segment level, which is the lowest level in the organization that constitutes a business for which discreet financial information is available.

Prior to September 30, 2008, substantially all of our goodwill related to our merchant energy segment. The lack of observable market prices for the merchant energy segment required us to estimate fair value, which we determined on a preliminary basis using the income valuation approach by computing discounted cash flows, consistent with prior evaluations. Although our estimate of discounted cash flows exceeded the carrying value of the merchant energy segment, because our common stock continued to trade at a price less than carrying value for the entire company throughout the last half of September and all of October, we also estimated fair value for the merchant energy segment using current market price information.

The primary inputs and assumptions to our estimate of fair value based upon market information were as follows:

- the fair value of Constellation Energy based upon recent market prices of our common stock,
- the estimated fair value of BGE, and
- the estimated value of the agreements executed with MidAmerican.

Using this information, we deducted the estimated fair value of non-merchant energy segment businesses from the fair value of Constellation Energy as a whole in order to estimate the fair value of the merchant energy segment as of September 2008. Based upon this estimate, the fair value of the merchant energy segment was substantially less than its carrying value. The primary difference between this estimate and our modeled estimates using the discounted cash flow income approach is that the market price approach incorporated the market's valuation discount associated with our merchant energy segment due to its significant liquidity and collateral requirements. We believe that this was a more appropriate method for estimating fair value than the modeled valuation techniques because it incorporated observable market information to a greater extent, which reflects current market conditions, and because it required fewer and less subjective judgments and estimates than our modeled estimates.

As a final consideration during our September 2008 impairment evaluation, we also evaluated the circumstances surrounding MidAmerican's purchase of Constellation Energy and whether the current market price of our common stock should be considered to represent fair value for accounting purposes. While the transaction price for the purchase of Constellation Energy resulted from negotiations that occurred over an abbreviated period of time during which the Company was experiencing financial difficulty, ongoing trading of the stock at levels approximating the transaction price represented the market's present assessment of fair value in a liquid, active market. This is consistent with guidance issued by the Securities Exchange Commission Office of the Chief Accountant and FASB Staff on the determination of fair value in distressed markets.

Based on our evaluation of these alternative measures of fair value, we determined that the fair value of the merchant energy business segment was less than its carrying value. Therefore, in order to measure the potential impairment of goodwill, we estimated the fair value of the merchant energy segment's assets and liabilities. We determined that the fair value of its assets net of liabilities substantially exceeded the segment's total fair value, indicating that the merchant energy segment's goodwill was impaired as of September 30, 2008. Accordingly, we recorded a pre-tax charge of $266.5 million to write-off the entire balance of our merchant energy segment goodwill substantially all of which was recorded in the third quarter of 2008. This charge is recorded in "Impairment losses and other costs" in our Consolidated Statements of Income (Loss).

Other Costs

In September 2008, we entered into a non-binding agreement to settle a class action complaint that alleged a subsidiary's ash placement operations at a third party site damaged surrounding properties. In December 2008, the settlement was approved by the court. As a result of this agreement, we recorded a $14.0 million pre-tax charge net of an expected insurance recovery.

Workforce Reduction Costs

We incurred costs related to workforce reduction efforts initiated at our nuclear generating facilities in 2006 and 2007. We substantially completed both of these workforce reduction efforts during 2008.

In September 2008, our merchant energy business approved a restructuring of the workforce at our Customer Supply operations. We recognized a $2.5 million pre-tax charge during 2008 related to the elimination of approximately 100 positions associated with this restructuring. The restructuring is expected to be completed within the next 12 months.

During the fourth quarter of 2008, we approved a restructuring of the workforce across all of our operations. We recognized a $19.7 million pre-tax charge in 2008 related to the elimination of approximately 380 positions. The restructuring is expected to be completed within the next twelve months. We expect to incur additional workforce reduction costs in 2009.

Emissions Allowances

The Clean Air Interstate Rule (CAIR) required states in the eastern United States to reduce emissions of sulfur dioxide (SO_2) and established a cap-and-trade program for annual nitrogen oxide (NO_x) emission allowances. On July 11, 2008, the United States Court of Appeals for the D.C. Circuit (the "Court") issued an opinion vacating CAIR, subject to petitions for rehearing. The Environmental Protection Agency (EPA) filed a petition for rehearing. On December 23, 2008, the Court reversed its earlier decision to revoke CAIR and will allow CAIR to remain in effect until it is replaced by a revised rule issued by the EPA that would preserve the environmental rules established by CAIR. The Court did not propose a deadline by which the EPA must correct the flaws identified with CAIR but it did state that it will accept petitions if the EPA does not remedy the problems previously identified in its July 11, 2008 opinion.

As a result of the Court's December 2008 decision, the annual NO_x program will become effective in 2009 as originally established by CAIR. In addition, since the December 2008 decision, market prices for 2009 NO_x allowances have increased significantly, with lesser increases shown in allowances for subsequent years. There was also an increase in trading volumes for annual NO_x. For the SO_2 program, the EPA will be required to issue a new rule that would replace the allowances issued under Title IV of the Clean Air Act with a new, reduced pool of allowances which would meet or exceed existing CAIR targets. Market prices for SO_2 allowances have also risen since the Court's decision.

We account for our emission allowance inventory at the lower of cost or market, which includes consideration of our expected requirements related to the future generation of electricity. The weighted-average cost of our 2008 SO_2 allowance inventory in excess of amounts needed to satisfy these requirements was greater than market value at June 30, 2008 and market prices decreased further for both SO_2 and annual NO_x emission allowances through September 30, 2008. After giving consideration to the Court's July 11, 2008 decision and the subsequent decline in the market price of these allowances, we recorded a write-down of our SO_2 allowance inventory totaling $22.1 million pre-tax to reflect the June 30, 2008 market prices. At September 30, 2008, we recorded an additional write-down of our SO_2 emission allowance inventory and recorded a write-down of our annual NO_x allowance inventory totaling $58.9 million to reflect the September 30, 2008 prices. These write-downs were recorded in the "Nonregulated revenues" line in our Consolidated Statements of Income (Loss). The third quarter 2008 write-down was partially offset by mark-to-market gains totaling $22.2 million pre-tax on derivative contracts for the forward sale of emission allowances. This gain reflects the impact of lower market prices on the value of those derivative contracts.

Due to the recent increases in SO_2 and NO_x emission allowance prices stemming from the December 23, 2008 Court ruling, we evaluated the value of our emissions allowances and determined that, in accordance with Accounting Principles Board Opinion No. 28, *Interim Financial Information*, a partial reversal of prior interim period write-downs was appropriate. At December 31, 2008, we reversed $11.4 million of the second and third quarter of 2008 write-downs. The prices at December 31, 2008 create a new cost basis for SO_2 and annual NO_x emission allowances and cannot be further written-up in future periods. Our mark-to-market gains on derivative contracts for the forward sale of emission allowances were $0.7 million for the quarter ended December 31, 2008. At this time, we cannot predict the outcome of any further judicial, regulatory or legislative developments or their impact on the emission allowance markets.

Net Gain on Sale of Upstream Gas Assets

On March 31, 2008, we sold our working interest in oil and natural gas producing properties in Oklahoma to CEP, a related party, and recognized a gain of $14.3 million, net of the minority interest gain of $0.7 million. We discuss this transaction in more detail in *Note 16.*

In addition, on June 30, 2008, our merchant energy business sold a portion of its working interests in proved natural gas reserves and unproved properties in Arkansas to an unrelated party for total proceeds of $145.4 million, which is subject to certain purchase price adjustments. Our merchant energy business recognized a $77.7 million pre-tax gain on this sale.

In December 2008, our merchant energy business sold working interests in proved natural gas reserves in Wyoming, and our equity investment in certain entities that own interests in proved natural gas reserves and unproved properties in Texas and Montana to unrelated parties for total proceeds of $55.7 million, subject to certain purchase price adjustments. Our merchant energy business recognized a $67.2 million pre-tax loss on these sales.

The net gain is included in "Net Gains on Sales of Upstream Gas Assets" line in our Consolidated Statements of Income (Loss).

Gain on Sale of Dry Bulk Vessel

On July 10, 2008, a shipping joint venture, in which our merchant energy business has a 50% ownership interest, sold one of the six dry bulk vessels it owns. Our merchant energy business recognized a $29.0 million pre-tax gain on this sale. The gain is included in "Nonregulated revenues" line in our Consolidated Statements of Income (Loss).

Maryland Settlement Agreement Customer Rate Credit

In March 2008, Constellation Energy, BGE and a Constellation Energy affiliate entered into a settlement agreement with the State of Maryland, the Maryland PSC and certain State of Maryland officials to resolve pending litigation and to settle other prior legal, regulatory and legislative issues. On April 24, 2008, the Governor of Maryland signed enabling legislation, which became effective on June 1, 2008. Pursuant to the terms of the settlement agreement:

Each party acknowledged that the agreements adopted in 1999 relating to Maryland's electric restructuring law are final and binding and the Maryland PSC will close ongoing proceedings relating to the 1999 settlement.

BGE provided its residential electric customers $189.1 million in the form of a one-time $170 per customer rate credit. We recorded a reduction to "Electric revenues" on our and BGE's Consolidated Statements of Income (Loss) during the second quarter of 2008 and reduced customers' bills by the amount of the credit between September and December 2008.

BGE customers are relieved of the potential future liability for decommissioning Constellation Energy's Calvert Cliffs Unit 1 and Unit 2, scheduled to occur no earlier than 2034 and 2036, respectively, and are no longer obligated to pay a total of $520 million, in 1993 dollars adjusted for inflation, pursuant to the 1999 Maryland PSC order regarding the deregulation of electric generation. BGE will continue to collect the $18.7 million annual nuclear decommissioning charge from all electric customers through 2016 and continue to rebate this amount to residential electric customers, as previously required by

Senate Bill 1, which had been enacted in June 2006.

BGE resumed collection of the residential return portion of the SOS administrative charge, which had been eliminated under Senate Bill 1, on June 1, 2008 and will continue collection through May 31, 2010 without having to rebate it to all residential electric customers. This will total approximately $40 million over this period. This charge will be suspended from June 1, 2010 through December 31, 2016.

Any electric distribution base rate case filed by BGE will not result in increased distribution rates prior to October 2009, and any increase in electric distribution revenue awarded will be capped at 5% with certain exceptions. Any subsequent electric distribution base rate case may not be filed prior to August 1, 2010. The agreement does not govern or affect BGE's ability to recover costs associated with gas rates, federally approved transmission rates and charges, electric riders, tax increases or increases associated with standard offer service power supply auctions.

Effective June 1, 2008, BGE implemented revised depreciation rates for regulatory and financial reporting purposes. The revised rates reduced depreciation expense approximately $14 million in 2008 without impacting rates charged to customers.

Effective June 1, 2008, Maryland laws governing investments in companies that own and operate regulated gas and electric utilities were amended to make them less restrictive with respect to certain capital stock acquisition transactions.

Constellation Energy elected two independent directors to the Board of Directors of BGE within the required six months from the execution of the settlement agreement.

2007 Events

	Pre-Tax	After-Tax
	(In millions)	
Impairment losses and other costs	**$ (20.2)**	**$ (12.2)**
Workforce reduction costs	**(2.3)**	**(1.4)**
Gain on sales of equity of CEP	**63.3**	**39.2**
Loss from discontinued operations		
High Desert	**(2.4)**	**(0.3)**
Puna		**(0.6)**
Total loss from discontinued operations	**(2.4)**	**(0.9)**
Total other items	**$ 38.4**	**$ 24.7**

Impairment Losses and Other Costs

In connection with the termination of the merger agreement with FPL Group, Inc. (FPL Group) in October 2006, we acquired certain rights relating to a wind development project in Western Maryland. In the second quarter of 2007, we elected not to make the additional investment that was required at that time to retain our rights in the project; therefore, we recorded a charge of $20.2 million pre-tax to write-off our investment in these development rights.

Workforce Reduction Costs

In June 2007, we approved a restructuring of the workforce at our Nine Mile Point nuclear facility related to the elimination of 23 positions. We recognized costs of $2.3 million pre-tax related to recording a liability for severance and other benefits under our existing benefit programs.

The following table summarizes the status of this involuntary severance liability for Nine Mile Point at December 31, 2008:

	(In millions)
Initial severance liability balance (1)	$ 2.6
Amounts recorded as pension and postretirement liabilities	(1.5)
Net cash severance liability	1.1
Cash severance payments	(0.7)
Other	(0.4)
Severance liability balance at December 31, 2008	$

(1)

Includes $0.3 million to be reimbursed from co-owner.

Gain on Sales of Equity of CEP

In November 2006, CEP, a limited liability company formed by Constellation Energy completed an initial public offering of 5.2 million common units at $21 per unit. See details under *2006 Events* later in this Note. In April 2007, CEP acquired 100% ownership of certain coalbed methane properties located in the Cherokee Basin in Kansas and Oklahoma. This acquisition was funded through CEP's sale of equity in which we did not participate.

As a result of the April 2007 equity issuance by CEP, our ownership percentage in CEP fell below 50 percent. Therefore, during the second quarter of 2007, we deconsolidated CEP and began accounting for our investment using the equity method under Accounting Principles Board Opinion (APB) No. 18, *The Equity Method of Accounting for Investments in Common Stock.* We discuss the equity method of accounting in more detail in *Note 1*.

In July and September 2007, CEP issued additional equity. In connection with our equity ownership in CEP, we recognize gains on CEP's equity issuances in the period that the equity is sold as common units or when converted to common units. The details of the 2007 CEP equity issuances, as well as the gains recognized by us, are summarized below:

	Units Issued	Price/ Unit	Proceeds to CEP	Pre-tax gain
	(In millions, except price/unit)			
April 2007 Sale				
Common units	2.2	$26.12	$ 58	$ 12.5
Class E units	0.1	25.84	2	0.4
July 2007 Sale				
Common units	2.7	35.25	94	20.0
Class F units	2.6	35.25	92	11.2
September 2007 Sale				
Common units	2.5	42.50	105	19.2

Discontinued operations

In the fourth quarter of 2006, we completed the sale of six natural gas-fired plants, including the High Desert facility, which was classified as discontinued operations. We recognized an after-tax loss of $0.3 million as a component of "Income (loss) from discontinued operations" for 2007 due to post-closing working capital and income tax adjustments. In addition, during 2007, we recognized an after-tax loss of $0.6 million relating to income tax adjustments arising from the June 2004 sale of a geothermal generating facility in Hawaii that was also previously classified as discontinued operations.

Presented in the table below are the amounts related to discontinued operations that are included in "Income from discontinued operations" in our Consolidated Statements of Income (Loss):

	High Desert		International Investments		Total	
	2007	**2006**	**2007**	**2006**	**2007**	**2006**
			(In millions)			
Revenues	**$**	$ 161.2	**$**	$	**$**	$ 161.2
(Loss) income before income taxes	**(2.4)**	108.9			**(2.4)**	108.9
Net (loss) income	**(0.3)**	70.2			**(0.3)**	70.2
Pre-tax gain on sale		185.2		1.4		186.6
After-tax gain on sale		116.7		0.9		117.6
(Loss) income from discontinued operations, net of taxes	**(0.3)**	186.9		0.9	**(0.3)**	187.8

During 2007, we recognized an after-tax loss from discontinued operations of $(0.6) million, related to tax adjustments from the sale of Puna, a Hawaiian Geothermal facility, in 2004.

2006 Events

	Pre-Tax	After-Tax
	(In millions)	
Gain on sale of gas-fired plants	$ 73.8	$ 47.1
Workforce reduction costs	(28.2)	(17.0)
Merger-related costs	(18.3)	(5.7)
Gain on initial public offering of CEP	28.7	17.9
Income from discontinued operations		
High Desert	294.1	186.9
International investments	1.4	0.9
Total income from discontinued operations	295.5	187.8
Total other items	$351.5	$ 230.1

Sale of Gas-Fired Plants

In December 2006, we completed the sale of the following natural gas-fired plants owned by our merchant energy business:

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

We sold these gas-fired plants for cash of $1.6 billion, and recognized a pre-tax gain on the sale of $259.0 million of which $73.8 million was included in "Gain on sale of gas-fired plants" and $185.2 million was included in "Income from discontinued operations" in our Consolidated Statements of Income.

At the time of the agreement for sale, we evaluated these plants for classification as discontinued operations under SFAS No. 144. Discontinued operations classification only applies to assets held for sale that meet the definition of a component of an entity. A component of an entity comprises operations and cash flows that can be clearly distinguished, operationally and for financial reporting purposes, from the rest of the entity.

High Desert met the requirements to be classified as a discontinued operation because it had a power sales agreement for its full output, was determined to be a component of Constellation Energy, and had separately identifiable cash flows. The table above provides additional detail about the amounts recorded in "Income from discontinued operations" related to our High Desert facility.

The remaining gas-fired plants were managed within our merchant energy business as a group or on a portfolio basis because they have aggregated risks, were hedged as a group, and generated joint cash flows. These gas-fired plants do not meet the requirements to be classified as discontinued operations. The results of operations for these gas-fired plants, as well as the $73.8 million pre-tax gain on sale, remain classified in continuing operations.

International Investments

In the fourth quarter of 2005, we completed the sale of Constellation Power International Investments, Ltd. (CPII). We recognized an after-tax gain of $0.9 million for the year ended December 31, 2006 due to the resolution of an outstanding contingency related to the sale. We discuss the details of the outstanding contingency later in this Note.

Workforce Reduction Costs

In March 2006, we approved a restructuring of the workforce at our Ginna nuclear facility. In connection with this restructuring, 32 employees were terminated. During the quarter ended

March 31, 2006, we recognized costs of $2.2 million pre-tax related to recording a liability for severance and other benefits under our existing benefit programs.

We completed this workforce reduction effort in 2006. As a result, no involuntary severance liability was recorded at December 31, 2006.

In July 2006, we announced a planned restructuring of the workforce at our Nine Mile Point nuclear facility. We recognized costs during the quarter ended September 30, 2006 of $15.1 million pre-tax related to the elimination of 126 positions associated with this restructuring. We also initiated a restructuring of the workforce at our Calvert Cliffs nuclear facility during the third quarter of 2006 and we recognized costs of $2.9 million pre-tax related to the elimination of 30 positions associated with this restructuring.

In addition, we incurred a pre-tax settlement charge of $12.7 million in accordance with Statement of Financial Accounting Standards (SFAS) No. 88, *Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits*. This charge reflects recognition of the portion of deferred actuarial gains and losses associated with employees who were terminated as part of the restructuring or retired in 2006 and who elected to receive their pension benefit in the form of a lump-sum payment. In accordance with SFAS No. 88, a settlement charge must be recognized when lump-sum payments exceed annual pension plan service and interest cost. The total SFAS No. 88 settlement charge incurred in 2006 includes a pre-tax charge of $8.0 million as a result of the Nine Mile Point restructuring. We discuss the settlement charges that we recorded during 2006 in *Note 7*.

The following table summarizes the status of this involuntary severance liability for Nine Mile Point and Calvert Cliffs at December 31, 2008:

	(In millions)
Initial severance liability balance	$ 19.6
Amounts recorded as pension and postretirement liabilities	(7.3)
Net cash severance liability	12.3
Cash severance payments	(12.3)
Other	
Severance liability balance at December 31, 2008	$

The severance liability above includes $1.6 million of costs that the joint owner of Nine Mile Point Unit 2 reimbursed us.

Merger-Related costs

We incurred costs during 2006 related to the proposed merger with FPL Group. The merger was terminated in October 2006. These costs totaled $18.3 million pre-tax for 2006. In addition, during 2006 we recognized tax benefits of $5.3 million on merger costs incurred in 2005 that were not considered deductible for income tax purposes until the termination of the merger in 2006. Our total pre-tax merger-related costs were $35.3 million.

Initial Public Offering of CEP

In November 2006, CEP, a limited liability company formed by Constellation Energy, completed an initial public offering of 5.2 million common units at $21 per unit. The initial public offering resulted in cash proceeds of $101.3 million, after expenses associated with the offering, for Constellation Energy.

As a result of the initial public offering of CEP, we recognized a pre-tax gain of $28.7 million, or $17.9 million after recording deferred taxes on the gain.

3 Information by Operating Segment

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

- Our merchant energy business is nonregulated and during 2008 included:
  - full requirements load-serving sales of energy and capacity to utilities, cooperatives, and commercial, industrial, and governmental customers,
  - structured transactions and risk management services for various customers (including hedging of output from generating facilities and fuel costs),
  - deployment of risk capital through portfolio management and trading activities,
  - gas retail energy products and services to commercial, industrial, and governmental customers,
  - fossil, nuclear, and interests in hydroelectric generating facilities and qualifying facilities, and power projects in the United States,
  - upstream (exploration and production) and downstream (transportation and storage) natural gas operations,
  - coal sourcing and logistics services and uranium marketing services for the variable or fixed supply needs of global customers, 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 and provide water and energy savings projects and performance contracting 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.

In connection with efforts to improve our liquidity and reduce our business risk:

- we entered into a definitive agreement to sell a majority of our international commodities operation in January 2009,
- we entered into a definitive agreement to sell our gas trading operation in February 2009.
- we announced strategic initiatives to sell our upstream gas properties, subject to market conditions, and
- we entered into an Investment Agreement with EDF. See *Note 15* for more detail on the Investment Agreement with EDF.

We believe that the successful execution of these initiatives, as well as our other initiatives being undertaken to reduce risk in our merchant energy business, will reduce our exposure to activities that require contingent capital support and improve 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*.

During 2006, we sold six of our gas-fired facilities. We discuss the sales of our gas-fired plants in more detail in *Note 2*.

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. We present a summary of information by operating segment on the next page.

Divestitures

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

In January 2009, we entered into a definitive agreement to sell a majority of our international commodities operation. In February 2009, we entered into a definitive agreement to sell our Houston-based gas trading operation. Simultaneously, we signed a letter of intent to enter into a related transaction with an affiliate of the buyer under which that company would provide us with the gas supply needed to support our retail gas customer supply business, while reducing our credit requirements. We expect that both of these sales will close by the end of the second quarter of 2009, subject to certain regulatory approvals and other standard closing conditions. Upon closing of these transactions, we expect to recognize an aggregate pre-tax loss of not more than $200 million based on current commodity prices. The actual amount of the loss will be affected by the final consideration exchanged, which is based on the timing of the close, and by changes in commodity prices. The impact on cash is not expected to be material.

Collectively, we expect that both divestitures to return approximately $1 billion of currently posted collateral. In addition, we expect these divestitures to further reduce our downgrade collateral requirements by approximately $400 million. These reductions are based on current commodity prices, the final terms of the transactions, and the timing of collateral to be returned up to the close of the transactions, and, as a result, are subject to change.

	Reportable Segments			Holding Company and Other Nonregulated Businesses		
	Merchant Energy Business	Regulated Electric Business	Regulated Gas Business		Eliminations	Consolidated
				(In millions)		
2008						
Unaffiliated revenues	$ 15,880.9	$ 2,679.5	$ 1,004.7	$ 253.2	$	$ 19,818.3
Intersegment revenues	891.9	0.2	19.3	0.2	(911.6)	
Total revenues	16,772.8	2,679.7	1,024.0	253.4	(911.6)	19,818.3
Depreciation, depletion, and amortization	287.1	184.2	43.7	68.2		583.2
Fixed charges	191.4	123.5	29.5	1.7	16.2	362.3
Income tax expense (benefit)	(99.5)	(4.9)	25.5	0.6		(78.3)
Net (loss) income (1)	(1,357.4)	1.1	37.2	4.7		(1,314.4)
Segment assets (2)	13,857.9	4,620.3	1,392.4	3,508.5	(1,095.0)	22,284.1
Capital expenditures	1,675.0	388.0	74.0	86.0		2,223.0
2007						
Unaffiliated revenues	$ 17,545.1	$ 2,455.6	$ 943.0	$ 249.5	$	$ 21,193.2
Intersegment revenues	1,199.4	0.1	19.8	0.3	(1,219.6)	
Total revenues	18,744.5	2,455.7	962.8	249.8	(1,219.6)	21,193.2
Depreciation, depletion, and amortization	269.9	187.4	46.8	53.7		557.8
Fixed charges	86.9	107.6	30.9	8.6	71.6	305.6
Income tax expense	332.7	64.6	22.8	8.2		428.3
Income from discontinued operations	(0.9)					(0.9)
Net income (3)	678.3	97.9	28.8	16.5		821.5
Segment assets	15,947.7	4,378.4	1,293.6	458.6	(336.0)	21,742.3
Capital expenditures	1,178.0	340.0	62.0	85.0		1,665.0
2006						
Unaffiliated revenues	$ 16,048.2	$ 2,115.9	$ 890.0	$ 230.8	$	$ 19,284.9
Intersegment revenues	1,118.0		9.5	0.2	(1,127.7)	
Total revenues	17,166.2	2,115.9	899.5	231.0	(1,127.7)	19,284.9
Depreciation, depletion, and amortization	258.7	181.5	46.0	37.7		523.9
Fixed charges	191.7	86.9	28.9	10.5	10.7	328.7
Income tax expense (benefit)	250.2	78.0	27.0	(4.2)		351.0
Income from discontinued operations	186.9			0.9		187.8
Net income (4)	767.0	120.2	37.0	12.2		936.4
Segment assets	16,387.3	3,783.2	1,252.8	887.8	(509.5)	21,801.6
Capital expenditures	768.0	297.0	63.0	21.0		1,149.0

(1)

Our merchant energy business recognized the following after-tax charges: impairment losses and other costs of $470.7 million, workforce reduction costs of $9.3 million, merger termination and strategic alternatives costs of $1,204.4 million, net emission allowance write-down of $28.7 million, a net gain on the sale of upstream gas properties of $16.0 million, a gain on sale of a dry bulk vessel of $18.9 million, and an impairment charge of our nuclear decommissioning trust assets of $82.0 million. Our regulated electric business recognized after-tax charges related to workforce reduction costs of $2.8 million, the Maryland settlement credit of $126.5 million, partially offset by the impact on BGE's effective tax rate of the Maryland settlement credit of $16.0 million. Our regulated gas business recognized an after-tax charge related to workforce reduction costs of $1.0 million. Our holding company and other nonregulated business recognized an after-tax charge related to workforce reduction costs of $0.3 million. We discuss these items in more detail in Note 2.

(2)

At December 31, 2008, Holding Company and Other Nonregulated segment assets include approximately $1.6 billion of intercompany receivables from the merchant energy business, primarily relating to the allocation of merger termination costs of approximately $1.2 billion to these businesses, and $1.0 billion of restricted cash related to the issuance of Series B Preferred Stock to EDF. These funds are held at the holding company and are restricted for payment of the 14% Senior Notes held by MidAmerican. The 14% Senior Notes were repaid in full in January 2009.

(3)

Our merchant energy business recognized an after-tax loss of $12.2 million related to a cancelled wind development project, an after-tax gain of $39.2 million on sales of CEP equity, and an after-tax charge of $1.4 million for workforce reduction costs as described in more detail in Note 2.

(4)

Our merchant energy business recognized an after-tax gain of $47.1 million on sale of gas-fired plants and an after-tax gain of $17.9 million on the initial public offering of CEP as discussed in more detail in Note 2. Our merchant energy business, our regulated electric business, our regulated gas business, and our other nonregulated businesses recognized after-tax charges of $21.3 million, $0.8 million, $0.4 million, and $0.2 million for merger-related costs and workforce reduction costs as described in more detail in Note 2.

4 Investments

Investments in Qualifying Facilities and Power Projects, CEP, and Joint Ventures

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

At December 31,	2008	2007
	(In millions)	
Qualifying facilities and domestic power projects:		
Coal	**$ 119.5**	$ 119.6
Hydroelectric	**55.6**	54.7
Geothermal	**37.0**	37.6
Biomass	**58.2**	43.6
Fuel Processing	**15.0**	26.8
Solar	**6.9**	7.0
CEP	**17.7**	143.0
Joint Ventures:		
Shipping JV	**59.9**	56.6
UNE	**51.0**	52.2
Other	**0.2**	1.1
Total	**$ 421.0**	$ 542.2

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

At December 31,	2008	2007
	(In millions)	
Equity method	**$ 414.1**	$ 535.2
Cost method	**6.9**	7.0
Total	**$ 421.0**	$ 542.2

Our percentage voting interests in these investments accounted for under the equity method range from 20% to 50%. Equity in earnings of these investments was $76.8 million in 2008, $8.3 million in 2007, and $13.8 million in 2006. The increase in equity earnings from 2007 to 2008 primarily relates to the $29.0 million pre-tax gain recognized in 2008 by our shipping joint venture upon the sale of one dry bulk vessel and the cessation of operations at a synthetic fuel facility at December 31, 2007.

We describe each of these investments below.

Qualifying Facilities and Power Projects

Our merchant energy business holds up to a 50% voting interest in 18 operating domestic energy projects that consist of electric generation, fuel processing, or fuel handling facilities. Of these 18 projects, 16 are "qualifying facilities" that receive certain exemptions and pricing under the Public Utility Regulatory Policies Act of 1978 based on the facilities' energy source or the use of a cogeneration process.

CEP

In November 2006, CEP, a limited liability company formed by our merchant energy business, completed an initial public offering. As of December 31, 2006, we owned approximately 54% of CEP and consolidated CEP. During the second quarter of 2007, CEP issued additional equity to the public and our ownership percentage fell below 50%. Therefore, we deconsolidated CEP and began accounting for our investment using the equity method under Accounting Principles Board Opinion (APB) No. 18, *The Equity Method of Accounting for Investments in Common Stock*. As of December 31, 2008, we hold a 28.5% voting interest in CEP.

During 2008, as a result of significant declines in the stock market, we determined that the decline in the value of our investment in CEP is other than temporary. Therefore, we recorded an approximately $124 million pre-tax impairment charge during 2008 to write-down our investment to fair value as of December 31, 2008.

Joint Ventures

In December 2006, we formed a shipping joint venture in which our merchant energy business has a 50% ownership interest. The joint venture currently owns and operates five dry bulk vessels. The joint venture sold one dry bulk vessel in 2008. See *Note 2* for more detail on this sale. In 2008 and 2007, we made cash contributions of approximately $5 million and $57 million, respectively, to the joint venture.

In August 2007, we formed a joint venture, UniStar Nuclear Energy, LLC (UNE) with EDF. We have a 50% ownership interest in this joint venture to develop, own, and operate new nuclear projects in the United States and Canada. The agreement with EDF includes a phased-in investment of $625 million by EDF in UNE. In 2008, EDF invested $175 million in UNE and we contributed land with a book value of $1.7 million. In 2007, EDF invested $350 million in UNE, and we contributed the new nuclear line of businesses we had developed over the prior two years, which included assets with a book value of $48.7 million and the right to develop possible new nuclear projects at our existing nuclear plant locations. Upon reaching certain licensing milestones, EDF will contribute up to an additional $100 million in UNE.

As of December 31, 2008, UNE's capitalized construction work in progress was approximately $301 million. Such amounts are being capitalized based on UNE's assessment that construction of new nuclear projects is probable. Should that expectation change, previously capitalized costs would be written off. In the event that our portion of any losses incurred by UNE exceed our investment, we will continue to record those losses in earnings unless it is determined that UNE will cease operations and subsequently be dissolved.

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 December 31, 2008	*Adjusted Cost*	*Unrealized Gains*	*Unrealized Losses*	*Fair Value*
		(In millions)		
Money market funds	**$ 17.6**	**$**	**$**	**$ 17.6**
Marketable equity securities	**700.9**	**41.5**	**(2.1)**	**740.3**
Corporate debt and U.S. treasuries	**224.8**	**6.8**		**231.6**
State municipal bonds	**46.2**	**1.3**		**47.5**
Totals	**$ 989.5**	**$ 49.6**	**$ (2.1)**	**$ 1,037.0**

At December 31, 2007	**Adjusted Cost**	**Unrealized Gains**	**Unrealized Losses**	**Fair Value**
		(In millions)		
Money market funds	$ 11.7	$	$	$ 11.7
Marketable equity securities	819.9	266.3	(0.2)	1,086.0
Corporate debt and U.S. treasuries	224.5	5.4		229.9
State municipal bonds	48.3	2.5		50.8
Totals	$ 1,104.4	$ 274.2	$ (0.2)	$ 1,378.4

In addition, the nuclear decommissioning trust funds included cash of $3.6 million at December 31, 2008. There was no cash at December 31, 2007.

The unrealized gains in the preceding tables consist primarily of $49.6 million and $256.7 million in 2008 and 2007, respectively, 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 $165.0 million and $8.5 million in pre-tax impairment losses on our nuclear decommissioning trust investments during 2008 and 2007, 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:

Year ended December 31,	**2008**	**2007**	**2006**
		(In millions)	
Gross realized gains	**$ 49.6**	$ 33.5	$ 13.3

Gross realized losses	**(210.4)**	(30.9)	(13.0)
Net realized (losses) gains	**$ (160.8)**	$ 2.6	$ 0.3

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

At December 31, 2008	***(In millions)***
Less than 1 year	$ 15.2
1-5 years	75.2
5-10 years	89.5
More than 10 years	99.2
Total maturities of debt securities	$ 279.1

Investments in Variable Interest Entities

We evaluate all transactions and relationships with potential variable interest entities (VIEs) in accordance with FASB Interpretation No. 46R, *Consolidation of Variable Interest Entities An Interpretation of ARB No. 51* (FIN 46R).

Our overall methodology for evaluating transactions and relationships under FIN 46R includes the following:

- determining whether the entity is a VIE, and, if so,
- determining whether we are the primary beneficiary of the VIE.

In performing the first step, the significant factors and judgments that we consider include:

- the design of the entity, including the nature of its risks and the purpose for which the entity was created, to determine the variability that the entity was designed to create and distribute to its interest holders,
- the nature of our involvement with the entity,
- whether control of the entity results through arrangements that do not involve voting equity,
- whether there is sufficient equity investment at risk to finance the activities of the entity, and
- whether parties other than the equity holders have the obligation to absorb expected losses or the right to receive expected residual returns.

For each VIE identified, we evaluate whether we are the primary beneficiary of the VIE by considering:

- whether our variable interest absorbs the majority of the VIE's expected losses,
- whether our variable interest receives the majority of the VIE's expected residual returns, and
- whether we have the ability to make decisions that significantly affect the VIE's results and activities.

Based on our evaluation of the above factors and judgments, as of December 31, 2008, we consolidated two VIEs in which we are the primary beneficiary. Also, as of December 31, 2008, we had significant interests in seven VIEs for which we did not have controlling financial interests and, accordingly, were not the primary beneficiary.

Consolidated Variable Interest Entities

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

BGE determined that BondCo is a variable interest entity for which it is the primary beneficiary. As a result, BGE and we consolidated BondCo. We discuss the consolidation method of accounting in more detail in *Note 1*.

The carrying amounts and classification of BondCo's assets and liabilities included in our consolidated financial statements at December 31, 2008 are as follows:

	(In millions)
Current assets	$ 23.7
Noncurrent assets	
Total Assets	$ 23.7
Current liabilities	$ 61.5
Noncurrent liabilities	510.9
Total Liabilities	$ 572.4

The BondCo assets above 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 2008, BGE remitted $87.2 million to BondCo.

BGE did not provide any additional financial support to BondCo during 2008. Further, BGE does not have any contractual commitments or obligations to provide additional financial support to BondCo unless additional rate stabilization bonds are issued. Alternatively, 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 2008, we consolidated a retail power supply VIE for which we became the primary beneficiary 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 December 31, 2008, we had significant interests in seven VIEs for which we are not the primary beneficiary. We have not provided any material financial or other support to these entities during 2008, except for $5 million provided to two fuel supply entities for working capital needs.

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	Combination of debt and equity financing	Power sale agreements, loans, and guarantees	$45.2 million in letters of credit	March 2005

(2 entities)				
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 (1 entity)	Equity financing and proceeds from gas sales	Gas supply agreement	$6.7 million in obligations under gas supply agreement and $3.7 million in payment guarantees	February 2008

For purposes of aggregating the various VIEs for disclosure, we evaluated the risk and reward characteristics for, and the significance of, each VIE. We discuss in greater detail the nature of our involvement with the power contract monetization VIEs in the *Power Contract Monetization VIEs* section below.

The following is summary information available as of December 31, 2008 about the VIEs in which we have a significant interest, but are not the primary beneficiary:

	Power Contract Monetization VIEs	**All Other VIEs**	**Total**
	(In millions)		
Total assets	$ 669.8	$ 303.0	$ 972.8
Total liabilities	526.5	99.1	625.6
Our ownership interest		52.5	52.5
Other ownership interests	143.3	151.4	294.7
Our maximum exposure to loss	45.2	64.9	110.1
Carrying amount and location of variable interest on balance sheet:			
Other investments		52.5	52.5

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 December 31, 2008 consists of the following:

- outstanding receivables, loans, and letters of credit totaling $51.9 million,
- the carrying amount of our investment totaling $52.5 million, and
- debt and payment guarantees totaling $5.7 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.

Power Contract Monetization VIEs

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

5 Intangible Assets

Goodwill

Goodwill is the excess of the cost of an acquisition over the fair value of the net assets acquired. As of December 31, 2008, our goodwill balance was primarily related to our other nonregulated businesses. Prior to September 30, 2008, our goodwill balance was primarily related to our merchant energy business acquisitions. Goodwill is not amortized; rather, it is evaluated for impairment at least annually. We evaluated our goodwill in 2008 and in 2007 and recorded a $266.5 million impairment charge in 2008, which related solely to our merchant energy segment. We discuss this impairment charge in more detail in *Note 2*.

The changes in the carrying amount of goodwill for the years ended December 31, 2008 and 2007 are as follows:

2008	***Balance at January 1,***	***Goodwill Acquired***	***Other (1)***	***Balance at December 31,***
		(In millions)		
Goodwill	**$ 261.3**	**$ 9.8**	**$ (266.5)**	**$ 4.6**

2007	**Balance at January 1,**	**Goodwill Acquired**	**Other (2)**	**Balance at December 31,**
		(In millions)		
Goodwill	$ 157.6	$ 103.4	$ 0.3	$ 261.3

(1) *Other represents impairment charges, which we discuss in Note 2.*

(2) *Other represents purchase price adjustments.*

For tax purposes, none of our goodwill balance at December 31, 2008 is deductible.

Intangible Assets Subject to Amortization

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

At December 31,	**2008**			**2007**		
	Gross Carrying Amount	**Accumul-ated Amortiz-ation**	**Net Asset**	**Gross Carrying Amount**	**Accumul-ated Amortiz-ation**	**Net Asset**
			(In millions)			
Software	**$ 554.9**	**$ (291.5)**	**$ 263.4**	$ 494.0	$ (232.3)	$ 261.7
Permits and licenses	**64.9**	**(10.0)**	**54.9**	62.3	(8.0)	54.3
Operating manuals and procedures	**38.6**	**(8.6)**	**30.0**	38.6	(8.4)	30.2
Other	**43.9**	**(22.6)**	**21.3**	26.8	(19.9)	6.9
Total	**$ 702.3**	**$ (332.7)**	**$ 369.6**	$ 621.7	$ (268.6)	$ 353.1

BGE had intangible assets with a gross carrying amount of $217.0 million and accumulated amortization of $131.4 million at December 31, 2008 and $194.4 million and accumulated amortization of $124.5 million at December 31, 2007 that are included in the table above. Substantially all of BGE's intangible assets relate to software.

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

Year Ended December 31,	2008	2007	2006
		(In millions)	
Nonregulated businesses	**$ 66.8**	$ 51.9	$ 37.2
BGE	**20.1**	20.2	18.6
Total Constellation Energy	**$ 86.9**	$ 72.1	$ 55.8

The following is our, and BGE's, estimated amortization expense related to our intangible assets for 2009 through 2013 for the intangible assets included in our, and BGE's, Consolidated Balance Sheets at December 31, 2008:

Year Ended December 31,	2009	2010	2011	2012	2013
			(In millions)		
Estimated amortization expense Nonregulated businesses	$62.2	$48.7	$38.4	$23.6	$15.1
Estimated amortization expense BGE	20.4	18.8	16.0	10.4	8.8
Total estimated amortization expense Constellation Energy	$82.6	$67.5	$54.4	$34.0	$23.9

Unamortized Energy Contracts

As discussed in *Note 1*, unamortized energy contract assets and liabilities represent the remaining unamortized balance of nonderivative energy contracts acquired, certain contracts which no longer qualify as derivatives due to the absence of a liquid market, or derivatives designated as normal purchases and normal sales, which we previously recorded as derivative assets and liabilities.

During 2007, we acquired several pre-existing power-related contracts that had been originated by other parties in prior periods when market prices were lower than current levels. The net proceeds received in this transaction were primarily recorded as a net liability in "Unamortized energy contracts."

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

At December 31		2008			2007	
	Carrying Amount	Accumul-ated Amortiz-ation	Net Liability	Carrying Amount	Accumul-ated Amortiz-ation	Net Liability
			(In millions)			
Unamortized energy contracts, net	**$ (2,332.3)**	**$ 1,286.8**	**$ (1,045.5)**	$ (2,290.0)	$ 889.5	$ (1,400.5)

The table below presents the estimated net favorable impact on our operating results for the amortization for these assets and liabilities over the next five-years:

Year Ended December 31,	2009	2010	2011	2012	2013
			(In millions)		

Estimated amortization	$347.4	$324.3	$107.8	$86.2	$82.7

6 Regulatory Assets (net)

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

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

At December 31,	**2008**	2007
	(In millions)	
Deferred fuel costs		
Rate stabilization deferral	**$ 536.3**	$ 593.4
Other	**24.4**	19.4
Electric generation-related regulatory asset	**118.0**	135.9
Net cost of removal	**(198.0)**	(182.3)
Income taxes recoverable through future rates (net)	**63.2**	63.9
Deferred smart energy savers program costs	**15.6**	
Deferred postretirement and postemployment benefit costs	**12.9**	16.1
Deferred environmental costs	**7.7**	8.9
Workforce reduction costs		2.4
Other (net)	**(5.7)**	(6.6)
Total regulatory assets (net)	**574.4**	651.1
Less: Current portion of regulatory assets (net)	**79.7**	74.9
Long-term portion of regulatory assets (net)	**$ 494.7**	$ 576.2

Deferred Fuel Costs

Rate Stabilization Deferral

In June 2006, Senate Bill 1 was enacted in Maryland and imposed a rate stabilization measure that capped rate increases by BGE for residential electric customers at 15% from July 1, 2006 to May 31, 2007. As a result, BGE recorded a regulatory asset on its Consolidated Balance Sheets equal to the difference between the costs to purchase power and the revenues collected from customers, as well as related carrying charges based on short-term interest rates from July 1, 2006 to May 31, 2007. In addition, as required by Senate Bill 1, the Maryland PSC approved a plan that allowed residential electric customers the option to further defer the transition to market rates from June 1, 2007 to January 1, 2008. During 2007, BGE deferred $306.4 million of electricity purchased for resale expenses and certain applicable carrying charges as a regulatory asset related to the rate stabilization plans. During 2008 and 2007, BGE recovered $57.1 million and $39.2 million, respectively, of electricity purchased for resale expenses and carrying charges related to the rate stabilization plan regulatory asset. BGE began amortizing the regulatory asset associated with the deferral which ended in May 2007 to earnings over a period not to exceed ten years when collection from customers began in June 2007. Customers who participated in the deferral from June 1, 2007 to December 31, 2007 are repaying the deferred charges without interest over a 21-month period which began in April 2008 and ends in December 2009.

Other

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

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

Electric Generation-Related Regulatory Asset

As a result of the deregulation of electric generation, BGE ceased to meet the requirements for the application of SFAS No. 71 for the previous electric generation portion of its business. In accordance with SFAS No. 101, *Regulated Enterprises Accounting for the Discontinuation of Application of FASB Statement No. 71*, and EITF 97-4, *Deregulation of the Pricing of Electricity Issues Related to the Application of FASB Statements No. 71 and 101,* BGE wrote-off all of its individual, generation- related regulatory assets and liabilities. BGE established a single, generation-related regulatory asset to be collected through its regulated transmission and distribution business, which is being amortized on a basis that approximates the pre-existing individual regulatory asset amortization schedules.

A portion of this regulatory asset represents income taxes recoverable through future rates that do not earn a regulated rate of return. These amounts were $72.4 million as of December 31, 2008 and $81.1 million as of December 31, 2007. We will continue to amortize this amount through 2017.

Another portion of this regulatory asset represented the decommissioning and decontamination fund payment for federal uranium enrichment facilities that did not earn a regulated rate of return on the rate base investment. Prior to the deregulation of electric generation, these costs were recovered through the electric fuel rate mechanism, and were excluded from rate base. This amount was $2.3 million at December 31, 2007. This amount was fully amortized at September 30, 2008.

Net Cost of Removal

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

Historically, under the group depreciation method, the anticipated costs of removing assets upon retirement were provided for over the life of those assets as a component of depreciation expense. However, effective January 1, 2003, we adopted SFAS No. 143, *Accounting for Asset Retirement Obligations.* In addition to providing the accounting requirements for recognizing an estimated liability for legal obligations associated with the retirement of tangible long-lived assets, SFAS No. 143 precludes the recognition of expected net future costs of removal as a component of depreciation expense or accumulated depreciation.

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

Income Taxes Recoverable Through Future Rates (net)

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

Deferred Smart Energy Savers Program Costs

Deferred Smart Energy Savers Program costs are the costs incurred to implement demand response and advanced metering programs. These programs are designed to help BGE manage peak demand, improve system reliability and improve service to customers by giving customers greater control over their energy use. Actual costs incurred in the demand response program, which began in January 2008, are being amortized over a 5-year period from the date incurred pursuant to an order by the Maryland PSC.

Deferred Postretirement and Postemployment Benefit Costs

Deferred postretirement and postemployment benefit costs are the costs we recorded under SFAS No. 106, *Employers' Accounting for Postretirement Benefits Other Than Pensions,* and SFAS No. 112, *Employers' Accounting for Postemployment Benefits,* in excess of the costs we included in the rates we charged our customers through 1997. We began amortizing these costs over a 15-year period in 1998.

Deferred Environmental Costs

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

Workforce Reduction Costs

The portions of the costs associated with our Voluntary Special Early Retirement Program and workforce reduction programs that relate to BGE's gas business were deferred as regulatory assets in accordance with the Maryland PSC's orders in prior rate cases. As a result of a 2005 gas base rate case, the remaining regulatory assets associated with workforce reductions totaling $7.3 million as of December 31, 2005 were amortized over a 3-year period that began in January 2006. These remaining regulatory assets were previously amortized over 5-year periods beginning in January and February 2002. This amount was fully amortized at December 31, 2008.

Other (Net)

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

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

We offer pension, postretirement, other postemployment, and employee savings plan benefits. BGE employees participate in the benefit plans that we offer. We describe each of our plans separately below. Nine Mile Point offers its own pension, postretirement, other postemployment, and employee savings plan benefits to its employees. The benefits for Nine Mile Point are included in the tables below.

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

At December 31,	2008	2007
	(In millions)	
Pension benefits	**$ 936.7**	$ 385.7
Postretirement benefits	**415.4**	421.5
Postemployment benefits	**59.9**	66.3
Total defined benefit obligations	**1,412.0**	873.5
Less: Amount recorded in other current liabilities	**57.7**	44.9
Total noncurrent defined benefit obligations	**$ 1,354.3**	$ 828.6

Pension Benefits

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

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

We fund the qualified plans by contributing at least the minimum amount required under IRS regulations. We calculate the amount of funding using an actuarial method called the projected unit credit cost method. The assets in all of the plans at December 31, 2008 and 2007 were mostly marketable equity and fixed income securities.

Postretirement Benefits

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

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

In 2003, the President signed into law the Medicare Prescription Drug Improvement and Modernization Act of 2003 (the Act). This legislation provides a prescription drug benefit for Medicare beneficiaries, a benefit that we provide to our Medicare eligible retirees. Our actuaries concluded that prescription drug benefits available under our postretirement medical plan are "actuarially equivalent" to Medicare Part D and thus qualify for the subsidy under the Act. This subsidy reduced our 2008 Accumulated Postretirement Benefit Obligation by $43.3 million and our 2008 postretirement medical payments by $2.4 million.

Liability Adjustments

At December 31, 2008 and 2007, our pension obligations were greater than the fair value of our plan assets for our qualified and our nonqualified pension plans as follows:

	Qualified Plans			
	Nine		***Non-Qualified***	
At December 31, 2008	***Mile***	***Other***	***Plans***	***Total***
		(In millions)		
Accumulated benefit obligation	**$ 123.7**	**$ 1,417.3**	**$ 99.8**	**$ 1,640.8**
Fair value of assets	**63.3**	**804.3**		**867.6**
Unfunded obligation	**$ 60.4**	**$ 613.0**	**$ 99.8**	**$ 773.2**

	Qualified Plans			
	Nine		**Non-Qualified**	
At December 31, 2007	**Mile**	**Other**	**Plans**	**Total**
		(In millions)		
Accumulated benefit obligation	$ 98.0	$ 1,332.2	$ 69.7	$ 1,499.9
Fair value of assets	78.6	1,179.9		1,258.5
Unfunded obligation	$ 19.4	$ 152.3	$ 69.7	$ 241.4

Effective December 31, 2006, we adopted SFAS No. 158, *Employer's Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statement No. 87, 106 and 132(R).* Under SFAS No. 158, we are required to reflect the funded status of our pension plans in terms of the projected benefit obligation, which is higher than the accumulated benefit obligation because it includes the impact of expected future compensation increases on the pension obligation. In addition, SFAS No. 158 requires us to reflect the funded status of our postretirement benefits in terms of the accumulated postretirement benefit obligation.

The net impact of adopting SFAS No. 158 in 2006 was to increase our pension and postretirement liabilities by $252.2 million, decrease the intangible asset by $28.6 million, and increase accumulated other comprehensive loss by $280.8 million pre-tax, or $169.5 million after-tax.

The following table summarizes the impact of SFAS No. 158 adjustments recorded at December 31, 2008 and 2007:

December 31,	Pension Liability	Postretirement Benefit Liability	Accumulated Other Comprehensive Income (Loss) Pre-tax	Accumulated Other Comprehensive Income (Loss) After-tax
		(In millions)		
2008	**$ 590.7**	**$ (9.5)**	**$ (581.2)**	**$ (347.1)**
2007	$ 3.1	$ (22.5)	$ 19.4	$ 11.6

Obligations and Assets

As a result of workforce reduction initiatives, pension and postretirement special termination benefits were recorded in 2008, 2007 and 2006. We discuss the workforce reduction initiatives further in *Note 2*.

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

	Pension Benefits		Postretirement Benefits	
	2008	**2007**	**2008**	**2007**
		(In millions)		
Change in benefit obligation (1)				
Benefit obligation at January 1	**$ 1,644.2**	$ 1,629.8	**$ 421.5**	$ 441.5
Service cost	**55.4**	49.4	**6.1**	6.5
Interest cost	**100.2**	94.7	**24.0**	24.4
Plan amendments	**12.1**			
Plan participants' contributions			**10.8**	8.7
Actuarial loss (gain)	**102.4**	(27.6)	**(9.5)**	(22.3)
Special termination benefits	**2.2**	1.2	**0.8**	0.3
Benefits paid (2)(3)	**(112.2)**	(103.3)	**(38.3)**	(37.6)
Benefit obligation at December 31	**$ 1,804.3**	$ 1,644.2	**$ 415.4**	$ 421.5

(1) *Amounts reflect projected benefit obligation for pension benefits and accumulated postretirement benefit obligation for postretirement benefits.*

(2) *Pension benefits paid include annuity payments and lump-sum distributions.*

(3) *Postretirement benefits paid are net of Medicare Part D reimbursements.*

	Pension Benefits		Postretirement Benefits	
	2008	**2007**	**2008**	**2007**
		(In millions)		

Change in plan assets				
Fair value of plan assets at January 1	**$ 1,258.5**	$ 1,161.2	**$**	$
Actual return on plan assets	**(364.9)**	71.3		
Employer contribution (1)	**86.2**	129.3	**27.5**	28.9
Plan participants' contributions			**10.8**	8.7
Benefits paid (2)(3)	**(112.2)**	(103.3)	**(38.3)**	(37.6)
Fair value of plan assets at December 31	**$ 867.6**	$ 1,258.5	**$**	$

(1)

Includes benefit payments for unfunded plans.

(2)

Pension benefits paid include annuity payments and lump-sum distributions.

(3)

Postretirement benefits paid are net of Medicare Part D reimbursements.

Net Periodic Benefit Cost and Amounts Recognized in Other Comprehensive Income

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

Year Ended December 31,	**2008**	**2007**	**2006**
		(In millions)	
Components of net periodic pension benefit cost			
Service cost	**$ 55.4**	$ 49.4	$ 49.0
Interest cost	**100.2**	94.7	89.3
Expected return on plan assets	**(111.3)**	(102.6)	(96.6)
Amortization of unrecognized prior service cost	**10.9**	5.2	5.7
Recognized net actuarial loss	**24.7**	32.7	37.3
Amount capitalized as construction cost	**(10.2)**	(11.7)	(13.4)
Net periodic pension benefit cost (1)	**$ 69.7**	$ 67.7	$ 71.3

(1)

Net periodic pension benefit cost excludes SFAS No. 88 termination benefits of $2.2 million in 2008, SFAS No. 88 termination benefits of $1.2 million in 2007, and SFAS No. 88 settlement charge of $12.7 million and termination benefits of $4.2 million in 2006. BGE's portion of our net periodic pension benefit costs, excluding amount capitalized, was $16.4 million in 2008, $21.8 million in 2007, and $25.0 million in 2006. The vast majority of our retirees are BGE employees.

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

Year Ended December 31,	2008	2007	2006
	(In millions)		
Components of net periodic postretirement benefit cost			
Service cost	**$ 6.1**	$ 6.5	$ 7.7
Interest cost	**24.0**	24.4	23.7
Amortization of transition obligation	**2.1**	2.1	2.1
Recognized net actuarial loss	**2.0**	4.1	6.6
Amortization of unrecognized prior service cost	**(3.5)**	(3.5)	(3.5)
Amount capitalized as construction cost	**(7.6)**	(7.7)	(8.2)
Net periodic postretirement benefit cost (1)	**$ 23.1**	$ 25.9	$ 28.4

(1)

Net periodic postretirement benefit cost excludes SFAS No. 106 termination benefits of $0.8 million in 2008, $0.3 million in 2007, and $3.5 million in 2006. BGE's portion of our net periodic postretirement benefit cost, excluding amounts capitalized, was $13.1 million in 2008, $15.5 million in 2007, and $16.6 million in 2006.

As a result of adopting SFAS No. 158, the following is a summary of amounts we have recorded in "Accumulated other comprehensive income" and of expected amortization of those amounts over the next twelve months:

	Pension Benefits		Postretirement Benefits		Expected Amortiz- ation Next
	2008	2007	2008	2007	12 Months
			(In millions)		
Unrecognized actuarial loss	**$ 999.8**	$ 445.9	**$ 78.7**	$ 90.2	$ 43.3
Unrecognized prior service cost	**22.5**	21.4	**(22.6)**	(26.2)	7.2
Unrecognized transition obligation			**8.5**	10.7	2.1
Total	**$ 1,022.3**	$ 467.3	**$ 64.6**	$ 74.7	$ 52.6

Expected Cash Benefit Payments

The pension and postretirement benefits we expect to pay in each of the next five calendar years and in the aggregate for the subsequent five years are shown below. These estimated benefits are based on the same assumptions used to measure the benefit obligation at December 31, 2008, but include benefits attributable to estimated future employee service.

		Postretirement Benefits		
	Pension Benefits	Before Medicare Part D	Subsidy	After Medicare Part D
		(In millions)		
2009	$ 152.3	$ 33.0	$ 2.7	$ 30.3
2010	151.6	33.7	2.9	30.8
2011	118.3	34.3	3.0	31.3
2012	131.1	34.5	3.2	31.3
2013	137.7	35.1	3.3	31.8
2014-2018	807.6	182.3	16.9	165.4

Assumptions

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

	Pension Benefits		Postretirement Benefits		Assumption Impacts Calculation
	2008	**2007**	**2008**	**2007**	**of**
Discount rate	**6.00%**	6.25%	**6.00%**	6.25%	Benefit Obligation and Periodic Cost
Expected return on plan assets	**8.75**	8.75	**N/A**	N/A	Periodic Cost
Rate of compensation increase	**4.0**	4.0	**4.0**	4.0	Benefit Obligation and Periodic Cost

Our discount rate is based on a bond portfolio analysis of high quality corporate bonds whose maturities match our expected benefit payments. Our 8.75% overall expected long-term rate of return on plan assets reflected our long-term investment strategy in terms of asset mix targets and expected returns for each asset class for this period. Effective in 2009, we reduced our expected long-term rate of return assumption to 8.50%.

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

At December 31,	2008	2007
Next year	**8.0%**	9.0%
Following year	**7.5%**	8.0%
Ultimate trend rate	**5.0%**	5.0%
Year ultimate trend rate reached	**2015**	2014

A one-percentage point increase in the health care inflation rate from the assumed rates would increase the accumulated postretirement benefit obligation by approximately $25 million as of December 31, 2008 and would increase the combined service and interest costs of the postretirement benefit cost by approximately $2 million annually.

A one-percentage point decrease in the health care inflation rate from the assumed rates would decrease the accumulated postretirement benefit obligation by approximately $21 million as of December 31, 2008 and would decrease the combined service and interest costs of the postretirement benefit cost by approximately $2 million annually.

Qualified Pension Plan Assets

The asset allocations for our qualified pension plans were as follows:

At December 31,	2008	2007
Equity securities	**54%**	62%
Debt securities	**35**	31
Other	**11**	7
Total	**100%**	100%

The category "Other" primarily represents investments in financial limited partnerships. Our long-term pension plan investment strategy is to seek an asset mix of 58% equity, 30% fixed income, and 12% other investments. We rebalance our portfolio periodically when the sum of equity and other investments differs from 70% by three percentage points or more, we change an outside investment advisor, or we make contributions to the trust.

We determine expected return on plan assets using a market-related value of plan assets that recognizes asset gains and losses ratably over a five-year period.

Contributions and Benefit Payments

We contributed $76 million to our qualified pension plans in March 2008, even though there was no IRS required minimum contribution in 2008. We expect to contribute $218 million to our qualified pension plans in 2009. Our non-qualified pension plans and our postretirement benefit programs are not funded. We estimate that we will incur approximately $21 million in pension benefits for our non-qualified pension plans and approximately $30 million for retiree health and life insurance costs net of Medicare Part D during 2009.

Other Postemployment Benefits

We provide the following postemployment benefits:

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

We recognized expense associated with our other postemployment benefits of $1.9 million in 2008, $16.7 million in 2007, and $9.6 million in 2006. BGE's portion of expense associated with other postemployment benefits was $2.2 million in 2008, $10.2 million in 2007, and

$5.6 million in 2006.

We assumed the discount rate for other postemployment benefits to be 5.00% in 2008 and 5.25% in 2007. This assumption impacts the calculation of our other postemployment benefit obligation and periodic cost.

Employee Savings Plan Benefits

We sponsor defined contribution savings plans that are offered to all eligible employees. The savings plans are qualified 401(k) plans under the Internal Revenue Code. In a defined contribution plan, the benefits a participant is to receive result from regular contributions to a participant account. Matching contributions to participant accounts are made under these plans. Matching contributions to these plans were as follows:

Year Ended December 31,	**2008**	**2007**	**2006**
		(In millions)	
Nonregulated businesses	**$ 17.6**	$ 16.1	$ 14.6
BGE	**5.8**	5.8	5.4
Total Constellation Energy	**$ 23.4**	$ 21.9	$ 20.0

8 Credit Facilities and Short-Term Borrowings

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

Constellation Energy

Constellation Energy had bank and other lines of credit under committed unsecured credit facilities totaling $6.2 billion at December 31, 2008 for short-term financial needs. We enter into these facilities to ensure adequate liquidity to support our operations. In addition, we had other uncommitted credit facilities, which had letters of credit of $17 million outstanding at December 31, 2008.

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 $6.2 billion as shown below. As of December 31, 2008, we had $3.6 billion in letters of credit issued and borrowed $485.7 million against those facilities. The weighted-average effective interest rate for this outstanding borrowing was 0.79% at December 31, 2008. At January 31, 2009, we had $3.5 billion in letters of credit issued and borrowed $1.2 billion against those facilities. We have also included the pro forma effect on our credit facilities, which are reduced or terminated upon the occurrence of certain events, of closing the transactions contemplated by the Investment Agreement with EDF, which is expected to occur in the third 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 (A)	1.23	
June 2009 (B)	0.60	
September 2013	0.35	
December 2009	0.15	
Total	$ 6.18	$ 2.32

(A) *Size of facility may be reduced by proceeds received from certain securities offerings or asset sales.*

(B) *We discuss this facility provided by EDF in more detail in the Other Sources of Liquidity section on the next page. Terminates at the earliest of satisfying conditions to exercise the put on assets having a value of at least $600 million under the put arrangement discussed on the next page, receipt of alternative financing of $600 million, or June 2009.*

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 December 31, 2008 and January 31, 2009, BGE had $1.0 million in letters of credit issued under this facility and borrowed $370.0 million against this facility. The weighted-average effective interest rate for this outstanding borrowing was 1.87% at December 31, 2008. As of December 31, 2007, BGE had $0.7 million of letters of credit issued under this facility.

In addition, at December 31, 2008 and January 31, 2009, BGE had no commercial paper outstanding. There was no commercial paper outstanding as of December 31, 2007.

Net Available Liquidity

The following table provides a summary of our net available liquidity at December 31, 2008:

	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

The following table provides our net available liquidity at January 31, 2009:

	As of January 31, 2009		
	Constellation Energy	BGE	Total Consolidated
	(In billions)		
Credit facilities	$ 6.2	$ 0.4	$ 6.6
Less: Letters of credit issued	(3.5)		(3.5)
Less: Cash drawn on credit facilities	(1.2)	(0.4)	(1.6)
Undrawn facilities	1.5		1.5
Less: Commercial paper outstanding			
Net available facilities	1.5		1.5
Add: Cash	0.8		0.8
Net available liquidity	$ 2.3	$	$ 2.3

In addition, Constellation Energy had $14.0 million of short-term borrowings outstanding at December 31, 2007 under a three year $50 million line of credit expiring in 2010 relating to our merchant energy business. The weighted-average effective interest rate for this outstanding borrowing was 7.44% at December 31, 2007. There were no short-term borrowings outstanding under this line of credit at December 31, 2008.

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. Exercise of the put option 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.

Also, EDF has provided us with a $600 million interim backstop liquidity facility, included in the Constellation Energy credit facilities disclosed on the prior page. In order to use this facility, we will need to certify to EDF that there is no availability for additional borrowings under any of our other existing credit facilities and that we have used our best effort to obtain financing from any other source on reasonable terms and have not been able to obtain such financing. This facility expires on the earliest of:

- the date approval is obtained to allow the exercise of the put arrangement on non-nuclear power plants for an aggregate amount equal to at least $600 million,
- the date on which we obtain alternative financing in an aggregate principal amount equal to at least $600 million, or
- June 16, 2009.

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 2008, we sold certain of our upstream gas properties and in 2009, we made progress on several other initiatives as discussed in more detail in *Note 3*.

Currently, we have certain agreements that contain provisions that would require a significant amount of additional collateral upon a credit rating downgrade. By the successful execution of the announced divestitures, we would expect a significant return of currently posted collateral and a reduction in our downgrade collateral requirements, subject to changes in commodity prices.

We believe that we will have sufficient liquidity to meet our ongoing requirements over the next 12 months. However, our liquidity projections include assumptions for commodity price changes, which are subject to significant volatility, and continued changes in our business operations resulting from our strategic initiatives. Also, we are exposed to certain operational risks that could have a significant impact on our liquidity. In addition, if we cannot successfully execute on our strategies, our available liquidity would be negatively affected, which would have a material adverse effect on our results of operations and financial condition.

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 December 31, 2008, the debt to capitalization ratio as defined in the credit agreements was 57%.

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 if the Investment Agreement with EDF has closed or been terminated and our Standard & Poors 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 Standard & Poors Rating Group senior unsecured debt rating is BBB- or lower and our Moody's Investors Service senior unsecured debt rating is Baa3 or lower.

The credit agreement of BGE contains a provision requiring BGE to maintain a ratio of debt to capitalization equal to or less than 65%. At December 31, 2008, the debt to capitalization ratio for BGE as defined in this credit agreement was 55%.

9 Capitalization

We detail in the table below our total capitalization, which includes long-term debt, common stock, and preference stock, as of December 31, 2008 and 2007.

At December 31,	2008	2007
	(In millions)	
Long-Term Debt		
Long-term debt of Constellation Energy		
Zero Coupon Senior Notes, due June 19, 2023	**$ 256.7**	$
8.625% Series A Junior Subordinated Debentures, due June 15, 2063	**450.0**	
8% Series B Mandatorily Redeemable Preferred Stock	**1,000.0**	
14% Senior Notes, due December 31, 2009	**1,000.0**	
6.125% Fixed-Rate Notes, due September 1, 2009	**500.0**	500.0
7.00% Fixed-Rate Notes, due April 1, 2012	**700.0**	700.0
4.55% Fixed-Rate Notes, due June 15, 2015	**550.0**	550.0
7.60% Fixed-Rate Notes, due April 1, 2032	**700.0**	700.0
Fair Value of Interest Rate Swaps	**55.9**	11.8
Total long-term debt of Constellation Energy	**5,212.6**	2,461.8
Long-term debt of nonregulated businesses		
Tax-exempt debt transferred from BGE effective July 1, 2000		
Pollution control loan, due July 1, 2011		36.0
Port facilities loan, due June 1, 2013	**10.0**	48.0
4.10% Pollution control loan, due July 1, 2014	**20.0**	20.0
Economic development loan, due December 1, 2018		35.0
Floating-rate pollution control loan, due June 1, 2027	**8.8**	8.8
Tax-exempt variable rate notes, due April 1, 2024	**75.0**	75.0
Tax-exempt variable rate notes, due December 1, 2025	**47.0**	47.0
Tax-exempt variable rate notes, due December 1, 2037	**65.0**	65.0
District Cooling facilities loan, due December 1, 2031	**25.0**	25.0
5.00% Mortgage note, due June 15, 2010	**1.6**	3.6
4.25% Mortgage note, due March 15, 2009	**0.2**	0.8
7.3% Fixed Rate Note, due June 1, 2012	**1.8**	1.8
South Carolina synthetic fuel facility loan, due January 15, 2008 (imputed interest rate of 3.47%)		3.0
Total long-term debt of nonregulated businesses	**254.4**	369.0
First Refunding Mortgage Bonds of BGE		
6.625% Series, due March 15, 2008		119.7
Total First Refunding Mortgage Bonds of BGE		119.7
Other long-term debt of BGE		
6.125% Notes, due July 1, 2013	**400.0**	
5.90% Notes, due October 1, 2016	**300.0**	300.0
5.20% Notes, due June 15, 2033	**200.0**	200.0
6.35% Notes, due October 1, 2036	**400.0**	400.0
Medium-term notes, Series E	**143.0**	174.5
Medium-term notes, Series G		140.0
Total other long-term debt of BGE	**1,443.0**	1,214.5
6.20% deferrable interest subordinated debentures due October 15, 2043 to BGE wholly owned BGE Capital Trust II relating to trust preferred securities	**257.7**	257.7

Rate stabilization bonds	**564.4**	623.2
Unamortized discount and premium	**(41.9)**	(4.8)
Current portion of long-term debt	**(2,591.5)**	(380.6)
Total long-term debt	**$ 5,098.7**	$ 4,660.5

At December 31,	2008	2007
	(In millions)	
Minority Interests (1)	**$ 20.1**	$ 19.2
BGE Preference Stock		
Cumulative preference stock not subject to mandatory redemption, 6,500,000 shares authorized 7.125%, 1993 Series, 400,000 shares outstanding, callable at $101.78 per share until June 30, 2009, and at lesser amounts thereafter	**40.0**	40.0
6.97%, 1993 Series, 500,000 shares outstanding, callable at $101.74 per share until September 30, 2009, and at lesser amounts thereafter	**50.0**	50.0
6.70%, 1993 Series, 400,000 shares outstanding, callable at $101.68 per share until December 31, 2009, and at lesser amounts thereafter	**40.0**	40.0
6.99%, 1995 Series, 600,000 shares outstanding, callable at $102.45 per share until September 30, 2009, and at lesser amounts thereafter	**60.0**	60.0
Total BGE preference stock not subject to mandatory redemption	**190.0**	190.0
Common Shareholders' Equity		
Common stock without par value, 600,000,000 shares authorized; 199,128,908 and 178,437,208 shares issued and outstanding at December 31, 2008 and 2007, respectively. (At December 31, 2008, 8,729,667 shares were reserved for the long-term incentive plans, and 1,508,553 shares were reserved for the employee savings plan.)	**3,164.5**	2,513.3
Retained earnings	**2,228.7**	3,919.5
Accumulated other comprehensive loss	**(2,211.8)**	(1,092.6)
Total common shareholders' equity	**3,181.4**	5,340.2
Total Capitalization	**$ 8,490.2**	$ 10,209.9

(1) *Effective January 1, 2009, minority interests will be renamed "noncontrolling interests" and be reclassified to the Common Shareholders' Equity section of this Statement of Capitalization in accordance with the adoption of SFAS No. 160. We discuss SFAS No. 160 in more detail in Note 1.*

Long-term Debt

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

Constellation Energy

In June 2008, we closed on the following transactions:

Issued $250.0 million of Zero Coupon Senior Notes due June 2023. Interest, compounded semi-annually, will be paid at maturity or when redeemed. The yield on these notes based on the original maturity date of June 2023 is 6.96%. These notes include a put option, which allows the holder to sell the notes back to us on the put option dates at a price equal to the principal amount plus accrued interest. The put option dates commence in June 2010 and occur yearly at that time through maturity, except for 2012 and 2015. As a result of the put option feature, these notes will be classified as a current liability beginning in June 2009.

Issued $450.0 million of Series A Junior Subordinated Debentures at 8.625% due June 15, 2063, but which can be automatically extended to no later than June 15, 2068 at our discretion. Interest is payable quarterly in March, June, September, and December. However, we may choose at any time to defer interest payments on these debentures for up to ten consecutive years. During this deferral period, interest will continue to accrue, compounded quarterly, and the deferred interest payments will accrue additional interest at a rate equal to the interest rate on these debentures.

In connection with this offering, Constellation Energy executed a replacement capital covenant (RCC) for the benefit of holders of Constellation Energy's 7.60% Notes due April 1, 2032. Under the terms of the RCC, Constellation Energy may not redeem, purchase or defease any subordinated debentures on or before June 15, 2033, or, if the maturity date is extended, the date which is 30 years prior to the maturity date of the subordinated debentures (but not later than June 15, 2038), unless a specified amount of qualifying securities are issued to non-affiliates in a replacement offering during the 180 days prior to the redemption, purchase or defeasance date. Qualifying securities include those that have equity-like characteristics that are the same as, or more equity-like than, the applicable characteristics of the subordinated debentures at the time of redemption, purchase or defeasance.

Mandatorily Redeemable Series B Preferred Stock

On December 17, 2008, Constellation Energy entered into an Investment Agreement with EDF. We discuss the Investment Agreement in more detail in *Note 15*. Simultaneously with the execution of the Investment Agreement, Constellation Energy issued 10,000 shares of 8% Series B Preferred Stock (Series B Preferred Stock) to EDF for $1 billion, which was restricted for the repayment of our 14% Senior Notes. If EDF completes the purchase of the 49.99% interest in our nuclear generation and operation business pursuant to the Investment Agreement, at the closing of that acquisition EDF will surrender to Constellation Energy all of the shares of the Series B Preferred Stock as partial payment for the purchase of the interest in our nuclear generation and operation business. As discussed in *Note 15*, we expect the transaction to close and the Series B Preferred Stock to be redeemed by the third quarter of 2009.

Because of the mandatory redemption provision, we accounted for the Series B Preferred Stock as debt and included it in the "Current portion of long-term debt" line on our Consolidated Balance Sheets. We report dividends in the "Interest expense" line on our Consolidated Statements of Income (Loss).

If the Investment Agreement is terminated, the Series B Preferred Stock will be redeemed at the later of the date of termination or December 31, 2009 for $1 billion aggregate principal amount of 10% Senior Notes of Constellation Energy due June 30, 2010.

So long as any shares of the Series B Preferred Stock are outstanding, Constellation Energy and its subsidiaries may not, without the consent of holders of at least a majority of then outstanding shares of the Series B Preferred Stock, undertake certain actions. Such actions include amending or revising our organizational documents, issuing equity senior or equal to the Series B Preferred Stock, authorizing a liquidation, incurring certain types of indebtedness, paying certain dividends, redeeming or repurchasing shares of capital stock, and entering into affiliate transactions.

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%.

Mandatorily Redeemable Series A Convertible Preferred Stock

On September 19, 2008, Constellation Energy entered into an Agreement and Plan of Merger with MidAmerican and, on December 17, 2008, Constellation Energy and MidAmerican mutually agreed to terminate the merger agreement. We discuss the termination of the merger agreement in more detail in *Note 15*. In connection with the merger agreement, Constellation Energy issued 10,000 shares of 8% Series A Convertible Preferred Stock (Series A Preferred Stock) to MidAmerican for $1 billion.

Upon termination of the merger agreement, the Series A Preferred Stock converted into $1 billion aggregate principal amount of 14% Senior Notes of Constellation Energy and the right for MidAmerican to receive the equivalent of 19.9% of the outstanding common shares. However, since regulatory approval to issue all of the required outstanding common shares was not received, in accordance with the terms of the Series A Preferred Stock, Constellation Energy issued the following to MidAmerican:

- 19,897,322 shares of our common stock (equivalent to 9.99% of the outstanding common shares) and,
- a cash payment of $418.2 million, equivalent to the $26.50 merger price per share multiplied by the portion of the total shares that could not be issued because all necessary regulatory approvals were not received.

The Senior Notes were repaid in full on January 12, 2009 together with accrued and unpaid interest through that date of approximately $5 million.

BGE

BGE's First Refunding Mortgage Bonds

We paid in full the last series of BGE's first refunding mortgage bonds outstanding in March 2008. These bonds were secured by a mortgage lien on all of BGE's assets. The generating assets BGE transferred to subsidiaries of Constellation Energy also were subject to the lien of BGE's mortgage, along with the stock of Safe Harbor Water Power Corporation and Constellation Enterprises, Inc. The assets were released from this lien following the discharge of the mortgage in October 2008.

BGE's Rate Stabilization Bonds

In June 2007, BondCo, a subsidiary of BGE, issued an aggregate principal amount of $623.2 million of rate stabilization bonds to recover deferred power purchase costs. We discuss BondCo in more detail in *Note 4*. Below are the details of the rate stabilization bonds at December 31, 2008:

Principal

	Interest Rate	Scheduled Maturity Date
$225.2	5.47%	October 2012
220.0	5.72	April 2016
119.2	5.82	April 2017

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

BGE's Other Long-Term Debt

In June 2008, BGE issued $400.0 million of 6.125% Notes due July 1, 2013. Interest is payable semi-annually on January 1 and July 1, beginning January 1, 2009.

On July 1, 2000, BGE transferred $278.0 million of tax-exempt debt to our merchant energy business related to the transferred generating assets. At December 31, 2008, BGE remains contingently liable for the $38.8 million outstanding balance of this debt.

BGE's fixed-rate medium-term note, series E, outstanding at December 31, 2008 has a weighted average interest rate of 6.72%, maturing between 2009 and 2012.

BGE Deferrable Interest Subordinated Debentures

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

BGE Trust II used the net proceeds from the issuance of common securities to BGE and the Trust Preferred Securities to purchase a series of 6.20% Deferrable Interest Subordinated Debentures due October 15, 2043 (6.20% debentures) from BGE in the aggregate principal amount of $257.7 million with the same terms as the Trust Preferred Securities. BGE Trust II must redeem the Trust Preferred Securities at $25 per preferred security plus accrued but unpaid distributions when the 6.20% debentures are paid at maturity or upon any earlier redemption. BGE has the option to redeem the 6.20% debentures at any time on or after November 21, 2008 or at any time when certain tax or other events occur.

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

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

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

Revolving Credit Agreement

On December 18, 2001, BGE's subsidiary, District Chilled Water Partnership (ComfortLink) entered into a $25.0 million loan agreement with the Maryland Energy Financing Administration (MEFA). The terms of the loan exactly match the terms of variable rate, tax exempt bonds due December 1, 2031 issued by MEFA for ComfortLink to finance the cost of building a chilled water distribution system. The interest rate on this debt resets weekly. These bonds, and the corresponding loan, can be redeemed at any time at par plus accrued interest while under variable rates. The bonds can also be converted to a fixed rate at ComfortLink's option.

Maturities of Long-Term Debt

Our long-term borrowings mature on the following schedule:

Year	Constellation Energy	Nonregulated Businesses	BGE	Total
		(In millions)		
2009	$ 2,500.0	$ 1.5	$ 65.0	$2,566.5
2010		0.4	56.5	56.9
2011		0.1	81.7	81.8
2012	723.2	1.6	172.5	897.3
2013		10.0	466.6	476.6
Thereafter	2,430.4	240.8	1,422.8	4,094.0
Total	$ 5,653.6	$ 254.4	$2,265.1	$8,173.1

The table above includes $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. In addition, at December 31, 2008, we had long-term loans totaling

$250.8 million that mature after 2008, which are periodically remarketed and could require repayment prior to maturity following any unsuccessful remarketing. At December 31, 2008, $25.0 million is classified as current portion of long-term debt at BGE.

During 2008, several of these long-term loans were unable to be remarketed. As a result, at December 31, 2008, we had repurchased $109.0 million of these loans. In January 2009, $109.0 million of these long-term loans that had previously been repurchased were subsequently remarketed. In February 2009, we decided to no longer attempt to remarket certain tax-exempt debt as we may retire this debt. As a result, we held $97 million of this debt during February 2009 and expect to hold an additional $22 million of this debt in March 2009.

Weighted-Average Interest Rates for Variable Rate Debt

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

At December 31,	**2008**	**2007**
Nonregulated Businesses (including Constellation Energy)		
Loans under credit agreements	**2.61%**	3.77%
Tax-exempt debt	**3.17%**	3.53%
Fixed-rate debt converted to floating *	**4.88%**	6.43%

*
As discussed in Note 13, we have entered into interest rate swaps relating to $450.0 million of our fixed-rate debt.

Preference Stock

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

the preference stock has one vote per share on any charter amendment which would create or authorize any shares of stock ranking prior to or on a parity with the preference stock as to either dividends or distribution of assets, or which would substantially adversely affect the contract rights, as expressly set forth in BGE's charter, of the preference stock, each of which requires the affirmative vote of two-thirds of all the shares of preference stock outstanding; and

whenever BGE fails to pay full dividends on the preference stock and such failure continues for one year, the preference stock shall have one vote per share on all matters, until and unless such dividends shall have been paid in full. Upon liquidation, the holders of the preference stock of each series outstanding are entitled to receive the par amount of their shares and an amount equal to the unpaid accrued dividends.

Common Stock

Issuances

When the merger agreement with MidAmerican was terminated, the Series A Preferred Stock converted into $1 billion aggregate principal amount of 14% Senior Notes of Constellation Energy and the right for MidAmerican to receive 19.9% of the outstanding common shares. However, since regulatory approval to issue all of the required outstanding common shares was not received, we were only able to issue 19,897,322 shares of our common stock (equivalent to 9.9% of the outstanding common shares).

As provided by the terms of the Series A Preferred Stock, we paid MidAmerican cash of $418.2 million for the portion of common shares that could not be issued.

Share Repurchase Program

In October 2007, our Board of Directors approved a common share repurchase program for up to $1 billion of our outstanding common shares. Subsequent to this approval, on October 31, 2007, we entered into an accelerated share repurchase agreement with a financial institution to repurchase a total of $250.0 million, and, on November 2, 2007, we purchased 2,023,527 of outstanding shares of our common stock, which represents the minimum number of shares deliverable under the agreement, for a total of $187.5 million.

We accounted for the accelerated share repurchase agreement as two separate transactions: as shares of common stock acquired at cost and a forward contract indexed to our own common stock. We accounted for the shares of common stock repurchased in November 2007 as a reduction to common shareholders' equity at cost. We accounted for the forward contract as a component of common shareholders' equity at fair value, which totaled $62.5 million at inception. The forward contract was settled on January 23, 2008 based on a discount to the volume-weighted average trading price of our common stock during that period. As a result, the financial institution delivered 514,376 additional shares to us to complete the transaction.

We did not repurchase any shares under this program during 2008. 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.

10 Taxes

The components of income tax expense are as follows:

Year Ended December 31,	2008	2007	2006
	(Dollar amounts in millions)		
Income Taxes			
Current			
Federal	**$ 2.8**	$ 168.2	$ 246.3
State	**48.1**	40.6	37.2
Current taxes charged to expense	**50.9**	208.8	283.5
Deferred			
Federal	**(101.6)**	184.7	50.7
State	**(21.2)**	41.5	23.7
Deferred taxes (credited) charged to expense	**(122.8)**	226.2	74.4
Investment tax credit adjustments	**(6.4)**	(6.7)	(6.9)
Income taxes per Consolidated Statements of Income (Loss)	**$ (78.3)**	$ 428.3	$ 351.0

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

Reconciliation of Income Taxes Computed at Statutory Federal Rate to Total Income Taxes			
(Loss) Income from continuing operations before income taxes (excluding BGE preference stock dividends)	**$ (1,379.5)**	$ 1,263.9	$ 1,112.8
Statutory federal income tax rate	**35%**	35%	35%
Income taxes computed at statutory federal rate	**(482.8)**	442.4	389.5
Increases (decreases) in income taxes due to			
Depreciation differences not normalized on regulated activities	**3.3**	3.7	3.6
Amortization of deferred investment tax credits	**(6.4)**	(6.7)	(6.9)
Synthetic fuel tax credits flowed through to income	**(4.5)**	(166.2)	(120.2)
Estimated synthetic fuel tax credit phase-out		110.3	44.3
Interest expense on mandatorily redeemable preferred stock	**7.8**		
Qualified decommissioning impairment loss	**(28.5)**		
State income taxes, net of federal income tax benefit	**17.3**	53.4	42.6
Merger-related transaction costs	**416.2**		(5.3)
Other	**(0.7)**	(8.6)	3.4
Total income taxes	**$ (78.3)**	$ 428.3	$ 351.0
Effective income tax rate	**5.7%**	33.9%	31.5%

State income tax expense recorded in 2008 reflects the impact of an increase in the State of Maryland corporate tax rate from 7% to 8.25% effective January 1, 2008 that was enacted into law on November 19, 2007. In accordance with SFAS No. 109, *Accounting for Income Taxes*, in 2007 we recognized a $0.7 million after-tax charge for the net impact of the changes in the Maryland tax rate on deferred income tax assets and liabilities. The impact of the Maryland tax rate change on BGE is discussed below.

BGE's effective tax rate was 28.7% in 2008, 40.7% in 2007, and 37.5% in 2006. In general, the primary difference between BGE's effective tax rate and the 35% statutory federal income tax rate for all years relates to Maryland corporate income taxes, net of the related federal income tax benefit. The decrease in BGE's effective tax rate in 2008 is due to lower taxable income related to the Maryland settlement agreement, which increased the relative percentage impact of favorable permanent tax adjustments on BGE's effective tax rate. BGE's after-tax effective state rate of 7.6% for 2007 includes an adjustment of deferred income tax liabilities to reflect the November 19, 2007 enactment into law of a change in the Maryland corporate income tax rate, as discussed above. In 2006, BGE's effective tax rate includes the benefit of merger-related costs incurred in 2005 that were deductible in 2006 as a result of the termination of the merger with FPL Group (0.5%) and a deduction for dividends paid to the employee savings plan (0.5%).

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

At December 31,	Constellation Energy 2008	Constellation Energy 2007	BGE 2008	BGE 2007
	(In millions)			
Deferred Income Taxes				
Deferred tax liabilities				
Net property, plant and equipment	**$ 1,432.5**	$ 1,570.7	**$ 604.4**	$ 583.8
Qualified nuclear decommissioning trust funds	**310.9**	360.3		
Regulatory assets, net	**295.5**	312.0	**295.5**	312.0
Derivative assets and liabilities, net	**310.6**	217.8		
Other	**126.6**	122.6	**32.5**	12.2
Total deferred tax liabilities	**2,476.1**	2,583.4	**932.4**	908.0
Deferred tax assets				
Asset retirement obligation	**391.6**	368.3		
Defined benefit obligations	**552.0**	362.0	**30.8**	61.6
Financial investments and hedging instruments	**949.7**	426.1		
Deferred investment tax credits	**17.8**	20.4	**4.3**	4.8
Other	**156.0**	118.8	**13.8**	11.9
Total deferred tax assets	**2,067.1**	1,295.6	**48.9**	78.3
Total deferred tax liability, net	**409.0**	1,287.8	**883.5**	829.7
Less: Current portion of deferred tax (asset)/liability	**(268.0)**	(300.7)	**40.2**	44.1
Long-term portion of deferred tax liability, net	**$ 677.0**	$ 1,588.5	**$ 843.3**	$ 785.6

Synthetic Fuel Tax Credits

Through December 31, 2007, our merchant energy business owned interests in several synthetic fuel facilities that manufactured solid synthetic fuel produced from coal as defined under the Internal Revenue Code (IRC) for which we could claim tax credits on our Federal income tax return. The synthetic fuel process involves combining coal material with a chemical reagent to create a significant chemical change. We requested and received private letter rulings from the IRS that the synthetic fuel produced from these facilities produced a significant chemical change and thus qualified for synthetic fuel tax credits. To date, the IRS has not disallowed any of the synthetic fuel tax credits from these facilities.

The IRC provided for a phase-out of synthetic fuel tax credits if average annual wellhead oil prices increased above certain levels. Based on these provisions, we recorded a 70% tax credit phase-out as a reduction in tax credits of $110.3 million during 2007. We did not record any synthetic fuel tax credits in 2008 as a result of the expiration of the availability of the tax credits in 2007 and the decommissioning of these facilities in 2008. We did, however, record an additional tax credit true-up adjustment of $4.5 million during 2008 related to our estimate of the 2007 tax credit phase-out.

Income Tax Audits

We file income tax returns in the United States and foreign jurisdictions. With few exceptions, we are no longer subject to U.S. federal, state and local, or non-U.S. income tax examinations by tax authorities for the years before 2005. In 2008, the IRS examination of our consolidated federal income tax returns for the tax years 2002 through 2004 was settled and the federal statute of limitations for those years is scheduled to expire on April 15, 2009. In addition, in 2008 the IRS initiated an audit of our consolidated federal income tax returns for the tax years 2005 through 2007. Although the final outcome of the 2005-2007 IRS audit and future tax audits is uncertain, we believe that adequate provisions for income taxes have been made for potential liabilities resulting from such matters.

Unrecognized Tax Benefits

The following table summarizes the change in unrecognized tax benefits during 2008 and 2007 and our total unrecognized tax benefits at December 31, 2008 and 2007:

	2008	2007
	(In millions)	
Total unrecognized tax benefits, January 1	$ 114.5	$ 104.0
Increases in tax positions related to the current year	112.2	13.3
Increases in tax positions related to prior years		3.8
Reductions in tax positions related to prior years	(15.5)	(6.0)
Reductions in tax positions related to audit settlements	(21.5)	
Reductions in tax positions as a result of a lapse of the applicable statute of limitations		(0.6)
Total unrecognized tax benefits, December 31 (1)	$ 189.7	$ 114.5

(1) *BGE's portion of our total unrecognized tax benefits at December 31, 2008 and 2007 was $4.8 million and $17.8 million, respectively.*

Increases in current year tax positions in 2008 are primarily due to unrecognized tax benefits of $93.6 million related to certain MidAmerican merger termination payments and related transaction fees that were expensed for financial accounting purposes and are expected to be deducted on our 2008 federal and state income tax returns. Other increases in current year tax positions include unrecognized tax benefits for repair and depreciation deductions measured at amounts consistent with prior IRS examination results and state income tax accruals.

In April 2008, we received a closing agreement from the State of Hawaii regarding audit examinations for the tax years 2001-2003. Additionally, in June 2008, we received notice that the United States Congressional Joint Committee on Taxation had approved the results of the IRS examination of our federal consolidated income tax returns for the 2002-2004 tax years. We reduced our liability for unrecognized tax benefits by $21.5 million to reflect the results of these audits. The impact of the audit settlements on income tax expense was immaterial.

Total unrecognized tax benefits as of December 31, 2008 of $189.7 million include outstanding state refund claims of approximately $48.3 million for which no tax benefit was recorded on our Consolidated Balance Sheets because refunds were not received and the claims do not meet the "more-likely-than-not" threshold.

If the total amount of unrecognized tax benefits of $189.7 million were ultimately realized, our income tax expense would decrease by approximately $159 million. However, the $159 million includes state tax refund claims of approximately $48 million discussed above 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 December 31, 2009, 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 (benefit) expense relating to liabilities for unrecognized tax benefits were as follows:

	For the Year Ended December 31, 2008	2007
	(In millions)	
Interest and penalties recorded as tax (benefit) expense	**$ (0.4)**	$ 4.7

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

Accrued interest and penalties recognized in our Consolidated Balance Sheets were $10.3 million, of which BGE's portion was $0.7 million at December 31, 2008, and $16.8 million, of which BGE's portion was $5.3 million, at December 31, 2007.

11 Leases

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

Outgoing Lease Payments

We, as lessee, lease certain facilities and equipment. The lease agreements expire on various dates and have various renewal options. We also enter into certain power purchase agreements which are accounted for as operating leases. Under these agreements, we are required to make fixed capacity payments, as well as variable payments based on actual output of the plants. We record these payments as "Fuel and purchased energy expenses" in our Consolidated Statements of Income (Loss). We exclude from our future minimum lease payments table the variable payments related to the output of the plant due to the contingency associated with these payments.

We also enter into time charter purchase agreements which entitle us to the use of dry bulk freight vessels in the management of our global coal and logistics services. Certain of these contracts must be accounted for as leases. During 2008 and 2007, we entered into time charter leases with terms ranging in duration from 1 to 60 months. These arrangements do not include provisions for material rent increases and do not have provisions for rent holidays, contingent rentals or other incentives. In 2008 and 2007, we recognized aggregate lease expense of approximately $477 million and $535 million, respectively, related to 49 and 65 dry bulk freight vessels, respectively, hired under time charter arrangements. The average term of these arrangements is approximately 4 months. We record the payments as "Fuel and purchased energy expenses" in our Consolidated Statements of Income (Loss).

We recognized expense related to our operating leases as follows:

	Fuel and purchased energy expenses	Operating expenses	Total
		(In millions)	
2008	$ 664.8	$ 25.4	$ 690.2
2007	758.7	28.2	786.9
2006	162.6	24.7	187.3

At December 31, 2008, we owed future minimum payments for long-term, noncancelable, operating leases as follows:

Year	Power Purchase Agreements	Other	Total
		(In millions)	
2009	$ 288.7	$ 26.1	$ 314.8
2010	218.7	22.6	241.3
2011	206.8	21.4	228.2
2012	192.5	19.4	211.9
2013	175.3	18.2	193.5
Thereafter	505.6	85.8	591.4
Total future minimum lease payments	$ 1,587.6	$ 193.5	$ 1,781.1

Sub-Lease Arrangements

We provide time charters of dry bulk freight vessels as part of the logistical services provided to our global customers that qualify as sub-leases of our time charter purchase contracts. In 2008 and 2007, we recorded sub-lease income of approximately $289 million and $214 million, respectively, related to our time charter sub-leases. We did not have any material sub-lease income for 2006. We record sub-lease income as part of "Nonregulated revenues" in our Consolidated Statements of Income (Loss). As of December 31, 2008, the future minimum rentals to be received for these time charters is shown below:

Year	**Time Charter Sub-Leases**
	(In millions)
2009	$ 51.4
2010	21.5
2011	9.8
2012	9.8
2013	9.8
Thereafter	48.2
Total future minimum lease rentals	$ 150.5

12 Commitments, Guarantees, and Contingencies

Commitments

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. These contracts expire during 2009, 2010, and 2011, representing 100% of our estimated requirements until September 2009, approximately 75% of our estimated requirements from October 2009 to May 2010, approximately 50% of our estimated requirements from June 2010 to September 2010, and approximately 25% of our estimated requirements from October 2010 to May 2011. These contracts are recoverable under the Provider of Last Resort agreement reached with the Maryland PSC and, therefore, are excluded from the following table.

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. These contracts are recoverable under BGE's gas cost adjustment clause discussed in *Note 1,* and therefore are excluded from the table later in this Note.

Our other nonregulated businesses have committed to gas purchases and to contributions of 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 December 31, 2008, we estimate our future obligations to be as follows:

	Payments				
	2009	2010-2011	2012-2013	Thereafter	Total
		(In millions)			
Merchant Energy:					
Purchased capacity and energy	$ 588.4	$ 282.2	$ 187.5	$ 227.3	$ 1,285.4
Fuel and transportation	1,648.5	1,531.4	718.0	1,292.2	5,190.1
Long-term service agreements, capital, and other	190.7	60.2	28.7	18.0	297.6
Total merchant energy	2,427.6	1,873.8	934.2	1,537.5	6,773.1
Corporate and Other:					
Long-term service agreements, capital, and other	61.5	3.7			65.2
Regulated:					
Purchase obligations and other	16.9	23.9	11.9	11.3	64.0

Total future obligations	$2,506.0	$1,901.4	$946.1	$ 1,548.8	$6,902.3

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 our power plants extend for terms into 2016 and provide for the sale of all or a portion of the actual output of certain of our power plants. Substantially all long-term contracts were executed at pricing that approximated market rates, including profit margin, at the time of execution.

Guarantees

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

At December 31, 2008	**Stated Limit**
	(In billions)
Constellation Energy guarantees	$ 16.04
Merchant energy business guarantees	0.07
BGE guarantees	0.25
Total guarantees	$ 16.36

At December 31, 2008, Constellation Energy had a total of $16.36 billion in guarantees in outstanding related to loans, credit facilities, and contractual performance of certain of its subsidiaries as described below.

- Constellation Energy guaranteed a face amount of $16.04 billion.
  - Constellation Energy guaranteed a face amount of $15.02 million 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 $3 billion at December 31, 2008, which represents the total amount the parent company could be required to fund based on December 31, 2008 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 $0.88 billion and provides an intercompany credit facility primarily on behalf of our nuclear generating facilities for nuclear insurance and credit support to ensure these plants have funds to meet expenses and obligations to safely operate and maintain the plants.
  - Constellation Energy guaranteed $0.14 billion to its other nonregulated businesses of which $25.0 million was recorded in our Consolidated Balance Sheets at December 31, 2008.
- Our merchant energy business guaranteed $68.0 million for loans, performance guarantees and other related 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.

Contingencies

Environmental Matters

Solid and Hazardous Waste

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

68th Street Dump

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.

Spring Gardens

In December 1996, BGE signed a consent order with the Maryland Department of the Environment that requires it to implement remedial action plans for contamination at and around the Spring Gardens site, located in Baltimore, Maryland. The Spring Gardens site was once used to manufacture gas from coal and oil. Based on remedial action plans and cost modeling performed in late 2006, BGE estimates its probable clean-up costs will total $43 million. BGE has recorded these costs as a liability in its Consolidated Balance Sheets and has deferred these costs, net of accumulated amortization and amounts it recovered from insurance companies, as a regulatory asset. Based on the results of studies at this site, it is reasonably possible that additional costs could exceed the amount BGE has recognized by approximately $3 million. Through December 31, 2008, BGE has spent approximately $41 million for remediation at this site. We do not expect the remaining clean-up costs to have a material effect on our financial results.

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

Air Quality

In late July 2005, we received two Notices of Violation (NOVs) from the Placer County Air Pollution Control District, Placer County California (District) alleging that the Rio Bravo Rocklin facility located in Lincoln, California had violated certain District air emission regulations between January 2003 and March 2005. We have a combined 50% ownership interest in the partnership which owns the Rio Bravo Rocklin facility. In July 2008, the partnership settled the allegations by agreeing to pay approximately $242,000, of which our share is $121,000, and to implement supplemental environmental projects at the facility over the next 18 months.

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 NOV to a subsidiary of Constellation Energy, as well as the other owners and the operator of the Keystone coal-fired power plant in Shelocta, Pennsylvania. We hold an approximately 21% interest in the Keystone plant. The NOV alleges that the plant performed various capital projects beginning in 1984 without complying with the new source review permitting requirements of the

Clean Air Act. The EPA also contends that the alleged failure to comply with those requirements are continuing violations under the plant's air permits. The EPA could seek civil penalties under the Clean Air Act for the alleged violations.

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

Water Quality

In October 2007, a subsidiary of Constellation Energy entered into a consent decree with the Maryland Department of the Environment relating to groundwater 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 $2.5 million of these costs as of December 31, 2008, resulting in a remaining liability at December 31, 2008 of $5.4 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.

In November 2007, a class action complaint was filed in Baltimore City Circuit Court alleging that the subsidiary's ash placement operations at the third party site damaged surrounding properties. The complaint seeks injunctive and remedial relief relating to the alleged contamination, unspecified compensatory damages for any personal injuries and property damages associated with the alleged contamination, and unspecified punitive damages. In September 2008, we entered into a non-binding agreement with representatives for the class action plaintiffs and, as a result, recorded a liability for the anticipated settlement. On October 31, 2008, we entered into a definitive settlement agreement which was approved by the Court in December 2008.

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 that 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. 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.

A lead plaintiff has not yet been appointed in the New York or Maryland securities class action lawsuits pursuant to the provisions of the Private Securities Litigation Reform Act and Constellation Energy and other defendants have accordingly not been required to respond to the complaints or take other action to defend the litigation. The Southern District of New York has granted the defendant's motion to transfer the two securities class actions filed there to the District of Maryland, to be coordinated with the securities class action filed there. 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 properly monitor the investment and by failing to properly monitor other fiduciaries. The Consolidated Action seeks 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 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 513 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.

Storage of Spent Nuclear Fuel

The Nuclear Waste Policy Act of 1982 (NWPA) required the federal government through the DOE, to develop a repository for, and disposal of, spent nuclear fuel and high-level radioactive waste. The NWPA and our contracts with the DOE required the DOE to begin taking possession of spent nuclear fuel generated by nuclear generating units no later than January 31, 1998. The DOE has stated that it will not meet that obligation until 2020 at the earliest.

This delay has required that we undertake additional actions related to on-site fuel storage at Calvert Cliffs and Nine Mile Point, including the installation of on-site dry fuel storage capacity at Calvert Cliffs. In January 2004, we filed a complaint against the federal government in the United States Court of Federal Claims seeking to recover damages caused by the DOE's failure to meet its contractual obligation to begin disposing of spent nuclear fuel by January 31, 1998. The case is currently stayed, pending litigation in other related cases.

In connection with our purchases of Nine Mile Point and Ginna, all of the former owners' rights and obligations related to recovery of damages for DOE's failure to meet its contractual obligations were assigned to us. However, we have an obligation to reimburse the former owner of Ginna for up to $10 million in recovered damages for such claims.

Nuclear Insurance

We maintain nuclear insurance coverage for Calvert Cliffs, Nine Mile Point, and Ginna in four program areas: liability, worker radiation, property, and accidental outage. These policies contain certain industry standard exclusions, including, but not limited to, ordinary wear and tear, and war.

In November 2002, the President signed into law the Terrorism Risk Insurance Act (TRIA) of 2002, which was extended by the Terrorism Risk Insurance Extension Act of 2005 and the Terrorism Risk Insurance Program Reauthorization Act of 2007. Under the TRIA, property and casualty insurance companies are required to offer insurance for losses resulting from certified acts of terrorism. Certified acts of terrorism are determined by the Secretary of the Treasury, in concurrence with the Secretary of State and Attorney General, and primarily are based upon the occurrence of significant acts of terrorism that intimidate the civilian population of the United States or attempt to influence policy or affect the conduct of the United States Government. Our nuclear liability, nuclear property and accidental outage insurance programs, as discussed later in this section, provide coverage for certified acts of terrorism.

If there were an accident or an extended outage at any unit of Calvert Cliffs, Nine Mile Point or Ginna, it could have a substantial adverse impact on our financial results.

Nuclear Liability Insurance

Pursuant to the Price-Anderson Act, we are required to insure against public liability claims resulting from nuclear incidents to the full limit of public liability. This limit of liability consists of the maximum available commercial insurance of $300 million and mandatory participation in an industry-wide retrospective premium assessment program. The retrospective premium assessment is $117.5 million per reactor, per incident, increasing the total amount of insurance for public liability to approximately $12.5 billion. Under the retrospective assessment program, we can be assessed up to $587.5 million per incident at any commercial reactor in the country, payable at no more than $87.5 million per incident per year. This assessment also applies in excess of our worker radiation claims insurance. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation (Consumer Price Index) at least every five years and are subject to state premium taxes. In addition, the U.S. Congress could impose additional revenue-raising measures to pay claims.

Worker Radiation Claims Insurance

We participate in the American Nuclear Insurers Master Worker Program that provides coverage for worker tort claims filed for radiation injuries. The policy provides a single industry aggregate limit of $200 million for occurrences of radiation injury claims against all those insured by this policy prior to January 1, 2003 and $300 million for occurrences of radiation injury claims against all those insured by this policy on or after January 1, 2003.

The sellers of Nine Mile Point retain the liabilities for existing and potential claims that occurred prior to November 7, 2001. In addition, the Long Island Power Authority, which continues to own 18% of Unit 2 at Nine Mile Point, is obligated to assume its pro rata share of any liabilities for retrospective premiums and other premium assessments. RG&E, the seller of Ginna, retains the liabilities for existing and potential claims that occurred prior to June 10, 2004. If claims under these policies exceed the coverage limits, the provisions of the Price-Anderson Act would apply.

Nuclear Property Insurance

Our policies provide $500 million in primary coverage at each nuclear plant Calvert Cliffs, Nine Mile Point, and Ginna. In addition, we maintain $1.8 billion of excess coverage at Ginna and $2.3 billion in excess coverage under a blanket excess program offered by the industry mutual insurer at both Calvert Cliffs and Nine Mile Point. Under the blanket excess policy, Calvert Cliffs and Nine Mile Point share $1.0 billion of the total $2.3 billion of excess property coverage. Therefore, in the unlikely event of two full limit property damage losses at Calvert Cliffs and Nine Mile Point, we would recover $4.5 billion instead of $5.5 billion.

Losses resulting from non-certified acts of terrorism are covered as a common occurrence, meaning that if non-certified terrorist acts occur against one or more commercial nuclear power plants insured by our nuclear property insurance company within a 12-month period, they would be treated as one event and the owners of the plants where the acts occurred would share one full limit of liability (currently $3.2 billion).

Accidental Nuclear Outage Insurance

Our policies provide indemnification on a weekly basis for losses resulting from an accidental outage of a nuclear unit. Coverage begins after a 12-week deductible period and continues at 100% of the weekly indemnity limit for 52 weeks and then 80% of the weekly indemnity limit for the next 110 weeks. Our coverage is up to $490.0 million per unit at Calvert Cliffs and Ginna, $420.0 million for Unit 1 of Nine Mile Point, and $401.8 million for Unit 2 of Nine Mile Point. This amount can be reduced by up to $98.0 million per unit at Calvert Cliffs and $84.0 million for Nine Mile Point Unit 1 and $80.4 million for Nine Mile Point Unit 2 if an outage of more than one unit is caused by a single insured physical damage loss.

Both the accidental nuclear outage insurance and the nuclear property insurance are currently purchased through the industry mutual insurance company. If accidents at plants insured by the mutual insurance company cause a shortfall of funds, all policyholders could be assessed, with our share being up to $93.1 million. During 2008, the Board of Directors for the industry mutual insurance company approved a change to our policy that, in the event of a credit-rating downgrade to below investment grade, would require us to post collateral in the form of a letter of credit or cash equal to $93.1 million. Alternatively, we would be required to purchase insurance.

Non-Nuclear Property Insurance

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

13 Derivatives and Fair Value Measurements

Use of Derivative Instruments

Nature of Our Business and Associated Risks

Our business activities primarily include our 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 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

<u>Risk Management Activities</u>

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

Accounting for Derivative Instruments

The accounting requirements for derivatives are governed by SFAS No. 133 which requires recognition of all qualifying derivative instruments as either assets or liabilities on the balance sheet at fair value.

Accounting Designation

We must evaluate new and existing transactions and agreements to determine whether they are derivatives. SFAS No. 133 permits several possible accounting treatments for derivatives that meet all of the applicable requirements of that standard. SFAS No. 133 requires mark-to-market 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 prescribed by SFAS No. 133, both at the time of designation and on an ongoing basis. The permissible accounting treatments under SFAS No. 133 include:

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

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

NPNS

We elect NPNS accounting for derivative contracts that provide for the purchase or sale of a physical commodity that will be delivered in quantities expected to be used or sold over a reasonable period in the normal course of business. Once we elect NPNS classification for a given contract, we do not 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 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 $2,614.9 million at December 31, 2008 and $1,498.7 million at December 31, 2007.

We expect to reclassify $1,565.8 million of net pre-tax losses on cash-flow hedges from "Accumulated other comprehensive loss" into earnings during the next twelve months based on market prices at December 31, 2008. However, the actual amount reclassified into earnings could vary from the amounts recorded at December 31, 2008, 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:

- $31.7 million pre-tax loss in 2008,
- $24.4 million pre-tax loss in 2007, and
- $35.3 million pre-tax loss in 2006.

The majority of the pre-tax loss reclassified in 2008 resulted from contracts that ceased to qualify for hedge accounting due to the announcement of the intention to sell a majority of our international commodities operation. The majority of the pre-tax loss reclassified in 2007 resulted from the deconsolidation of CEP. The majority of the pre-tax loss reclassified in 2006 resulted from the initial public offering of CEP and the sale of our gas-fired plants.

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 income" in our Consolidated Statements of Common Shareholders' Equity and Comprehensive Income. We reclassify gains and losses on the hedges from "Accumulated other comprehensive income" into "Interest expense" in our Consolidated Statements of Income (Loss) during the periods in which the interest payments being hedged occur.

Accumulated other comprehensive income includes net unrealized pre-tax gains on interest rate cash-flow hedges of prior debt issuances totaling $12.0 million at December 31, 2008 and $11.9 million at December 31, 2007. We expect to reclassify $0.7 million of pre-tax net gains on these cash-flow hedges from "Accumulated other comprehensive income" 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.

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 $55.9 million at December 31, 2008 and $11.8 million at December 31, 2007 and was recorded as an increase in our "Derivative assets" and an increase in our "Long-term debt." We had no hedge ineffectiveness on these interest rate swaps.

Hedge Ineffectiveness

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

Year ended December 31,	2008	2007	2006
		(In millions)	
Cash-flow hedges	**$ (121.0)**	$ (31.4)	$ 13.4
Fair value hedges	**20.6**	24.4	27.7
Total	**$ (100.4)**	$ (7.0)	$ 41.1

The ineffectiveness amounts in the table above exclude $31.8 million and $7.3 million of pre-tax losses for the years ended December 31, 2008 and 2007, respectively, representing the change in fair value of derivatives that no longer qualify for cash-flow hedge accounting. These amounts relate to periods of insufficient price correlation between the hedge and the risk being hedged, but the derivatives qualify for and remain designated as hedges prospectively. In addition, we did not recognize any gain/loss in 2008 related to the change in fair value for the portion of our fair value hedges excluded from ineffectiveness testing. However, we recognized a $3.8 million pre-tax loss in 2007 and a $8.9 million pre-tax gain in 2006 related to the change in value for the portion of our fair value hedges excluded from ineffectiveness testing.

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.

Origination Gains

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

- $73.8 million pre-tax in 2008 resulting from 6 transactions,

- $41.9 million pre-tax in 2007 resulting from 1 transaction, and

- $13.5 million pre-tax in 2006 resulting from 3 transactions.

Termination or Restructuring of Commodity Derivative Contracts

We may terminate or restructure in-the-money contracts in exchange for upfront cash payments and a reduction or cancellation of future performance obligations. The termination or restructuring of contracts allows us to lower our exposure to performance risk under these contracts. Such transactions resulted in the realization of the following amounts of pre-tax earnings that otherwise would have been recognized over the life of these contracts:

- $73.1 million pre-tax in 2008 resulting from 7 transactions,

$17.8 million pre-tax in 2007 resulting from 1 transaction, and

$56.7 million pre-tax in 2006 resulting from 3 transactions.

Fair Value Measurements

SFAS No. 157, *Fair Value Measurements*, 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 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.

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

Recurring Measurements

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 December 31, 2008	
	Assets	**Liabilities**
	(In millions)	
Cash equivalents	$ 928.5	$
Debt and equity securities	1,069.5	
Derivative instruments:		
Classified as derivative assets and liabilities:		
Current	1,465.0	(1,241.8)
Noncurrent	851.8	(1,115.0)
Total classified as derivative assets and liabilities	2,316.8	(2,356.8)
Classified as accounts receivable *	(1,244.6)	
Total derivative instruments	1,072.2	(2,356.8)
Total recurring fair value measurements	$ 3,070.2	$ (2,356.8)

*

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 "Restricted cash" in the Consolidated Balance Sheets. Debt and equity securities 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 as required by SFAS No. 157. A primary focus of SFAS No. 157 is the fair value hierarchy that provides information about how fair value measurements are determined. SFAS No. 157 requires each individual asset or liability that is remeasured at fair value on a recurring basis 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.

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 December 31, 2008. These gross balances are intended solely to provide information on sources of inputs to fair value and proportions of fair value involving objective versus subjective valuations and do not represent either our actual credit exposure or net economic exposure.

At December 31, 2008	**Level 1**	**Level 2**	**Level 3**	**Netting and Cash Collateral ***	**Total Net Fair Value**
			(In millions)		
Cash equivalents	$ 928.5	$	$	$	$ 928.5
Debt and equity securities	305.4	764.1			1,069.5

Derivative assets	1,565.2	45,499.3	4,793.6	(50,785.9)	1,072.2
Derivative liabilities	(1,728.7)	(46,969.1)	(4,756.6)	51,097.6	(2,356.8)
Net derivative position	(163.5)	(1,469.8)	37.0	311.7	(1,284.6)
Total	$ 1,070.4	$ (705.7)	$ 37.0	$ 311.7	$ 713.4

*

We present our derivative assets and liabilities in our Consolidated Balance Sheets on a net basis. We net derivative assets and liabilities, including cash collateral, when a legally enforceable master netting agreement exists between us and the counterparty to a derivative contract. At December 31, 2008, we included $223.0 million of cash collateral held and $534.7 million of cash collateral posted (excluding margin posted on exchange traded derivatives) in netting amounts in the above table. See discussion of FSP FIN 39-1 in Note 1 for more details on our net presentation.

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 SFAS No. 157 requires separate presentation of 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 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.

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 publicly traded individual 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:

- publicly traded individual securities 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
- commingled funds 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 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. These factors include:

forward commodity prices,

price volatility,

volumes,

location,

interest rates,

credit quality of counterparties and Constellation Energy, and

credit enhancements.

We also record valuation adjustments to reflect uncertainties associated with certain estimates inherent in the determination of the fair value of derivative assets and liabilities. The effect of these uncertainties is not incorporated in market price information or other market-based estimates used to determine fair value of our mark-to-market energy contracts. To the extent possible, we utilize market-based data together with quantitative methods for both measuring the uncertainties for which we record valuation adjustments and determining the level of such adjustments and changes in those levels.

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

Close-out adjustment represents the estimated cost to close out or sell to a third-party open mark-to-market positions. This valuation adjustment has the effect of valuing "long" positions (the purchase of a commodity) at the bid price and "short" positions (the sale of a commodity) at the offer price. We compute this adjustment using a market-based estimate of the bid/offer spread for each commodity and option price and the absolute quantity of our net open positions for each year. The level of total close-out valuation adjustments increases as we have larger unhedged positions, bid-offer spreads increase, or market information is not available, and it decreases as we reduce our unhedged positions, bid-offer spreads decrease, or market information becomes available. Prior to the adoption of SFAS No. 157 on January 1, 2008, to the extent that we are not able to obtain observable market information for similar contracts, the close-out adjustment is equivalent to the initial contract margin, thereby resulting in no gain or loss at inception. In the absence of observable market information, there is a presumption that the transaction price is equal to the market value of the contract, and therefore we do not recognize a gain or loss at inception. We recognize such gains or losses in earnings as we realize cash flows under the contract or when observable market data becomes available.

Unobservable input valuation adjustment upon adopting FAS No. 157, this adjustment was necessary when we were required to determine fair value for derivative positions using internally developed models that use unobservable inputs due to the absence of observable market information. Unobservable inputs to fair value may arise due to a number of factors, including but not limited to, the term of the transaction, contract optionality, delivery location, or product type. In the absence of observable market information that supports the model inputs, there is a presumption that the transaction price is equal to the market value of the contract when we transact in our principal market and SFAS No. 157 requires us to recalibrate our estimate of fair value to equal the transaction price. Therefore we do not recognize a gain or loss at contract inception on these transactions. We will recognize such gains or losses in earnings as we realize cash flows under the contract or when observable market data becomes available.

Credit-spread adjustment for risk management purposes, we compute the value of our derivative assets and liabilities using a risk-free discount rate. In order to compute fair value for financial reporting purposes, we adjust the value of our derivative assets to reflect the credit-worthiness of each counterparty based upon either published credit ratings, or equivalent internal credit ratings and associated default probability percentages. We compute this adjustment by applying a default probability percentage to our outstanding credit exposure, net of collateral, for each counterparty. The level of this adjustment increases as our credit exposure to counterparties increases, the maturity terms of our transactions increase, or the credit ratings of our counterparties deteriorate, and it decreases when our credit exposure to counterparties decreases, the maturity terms of our transactions decrease, or the credit ratings of our counterparties improve. As part of our evaluation, we assess whether the counterparties' published credit ratings are reflective of current market conditions. We review available observable data including bond prices and yields and credit default swaps to the extent it is available. We also consider the credit risk measurement implied by that data in determining our default probability percentages, and we evaluate its reliability based upon market liquidity, comparability, and other factors. Upon adoption of SFAS No. 157, we also use a credit-spread adjustment in order to reflect our own credit risk in determining the fair value of our derivative liabilities.

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

The Company's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the classification of assets and liabilities within the fair value hierarchy. Because of the long-term nature of certain assets and liabilities measured at fair value as well as differences in the availability of market prices and market liquidity over their terms, inputs for some assets and liabilities may fall into any one of the three levels in the fair value hierarchy or some combination thereof. While SFAS No. 157 requires us to classify these assets and liabilities in the lowest level in the hierarchy for which inputs are significant to the fair value measurement, a portion of that measurement may be determined using inputs from a higher level in the hierarchy.

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

	2008
	(In millions)
Balance at beginning of period	$ (147.1)
Realized and unrealized gains (losses):	
Recorded in income	471.2
Recorded in other comprehensive income	(511.9)
Purchases, sales, issuances, and settlements	37.6
Transfers into and out of Level 3	187.2
Balance as of December 31, 2008	$ 37.0
Change in unrealized gains recorded in income relating to derivatives still held as of December 31, 2008	$ 800.1

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

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

Nonrecurring Measurements

The table below sets forth by level within the fair value hierarchy our financial assets and liabilities that were measured at fair value on a nonrecurring basis during 2008:

	Fair Value at December 31, 2008	Level 1	Level 2	Level 3	Losses for the year ended December 31, 2008
			(In millions)		
Equity method investment	$ 17.7	$ 17.7	$	$	$ 124.4

As described more fully in *Note 2*, during the third and fourth quarters of 2008 we recorded other-than-temporary impairment charges of $54.7 million and $69.7 million, respectively, on our equity method investment in CEP. The fair value of CEP is a Level 1 measurement because CEP is a publicly traded stock on the New York Stock Exchange and the fair value is a quoted price in an active market.

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:

	2008	2007
At December 31,		

	Carrying Amount	Fair Value *	Carrying Amount	Fair Value
		(In millions)		
Investments and other assets Constellation Energy	**$ 2,264.5**	**$ 2,264.5**	$ 1,634.2	$ 1,634.5
Fixed-rate long-term debt:				
Constellation Energy (including BGE)	**6,995.4**	**6,290.3**	4,244.3	4,307.5
BGE	**2,265.1**	**1,990.2**	2,215.1	2,178.6
Variable-rate long-term debt:				
Constellation Energy (including BGE)	**736.7**	**736.7**	801.6	801.6
BGE				

*

As defined by SFAS No. 157.

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.

14 Stock-Based Compensation

Under our long-term incentive plans, we grant stock options, performance and service-based restricted stock, performance- and service-based units, and equity to officers, key employees, and members of the Board of Directors. In May 2007, shareholders approved Constellation Energy's 2007 Long-Term Incentive Plan, under which we can grant up to a total of 9,000,000 shares. Any shares covered by an outstanding award under any of our long-term incentive plans that are forfeited or cancelled, expire or are settled in cash will become available for issuance under the 2007 Long-Term Incentive Plan. At December 31, 2008, there were 8,729,667 shares available for issuance under the 2007 Long-Term Incentive Plan. At December 31, 2008, we had stock options, restricted stock, performance unit and equity grants outstanding as discussed below. We may issue new shares, reuse forfeited shares, or buy shares in the market in order to deliver shares to employees for our equity grants. BGE officers and key employees participate in our stock-based compensation plans. The expense recognized by BGE in 2008, 2007, and 2006 was not material to BGE's financial results.

Non-Qualified Stock Options

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

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

	2008	2007	2006
Risk-free interest rate	**2.57%**	4.69%	%
Expected life (in years)	**4.0**	4.0	
Expected market price volatility factor	**25.8%**	20.3%	%
Expected dividend yield	**1.85%**	2.5%	%

During 2006, no stock options were granted to employees in anticipation of the proposed merger with FPL Group, which was terminated in October 2006.

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

Summarized information for our stock option grants is as follows:

	2008		2007		2006	
	Shares	Weighted-Average Exercise Price	Shares	Weighted-Average Exercise Price	Shares	Weighted-Average Exercise Price
			(Shares in thousands)			
Outstanding, beginning of year	**6,145**	**$ 55.90**	6,051	$ 47.23	7,172	$ 45.24
Granted with exercise prices at fair market value	**1,434**	**93.79**	1,759	76.22		
Exercised	**(375)**	**47.02**	(1,411)	41.91	(1,050)	33.77
Forfeited/expired	**(1,146)**	**84.59**	(254)	67.85	(71)	45.22
Outstanding, end of year	**6,058**	**$ 59.99**	6,145	$ 55.90	6,051	$ 47.23
Exercisable, end of year	**4,665**	**$ 52.13**	4,043	$ 48.51	4,401	$ 46.94
		$ 18.75		$ 13.76		$

Weighted-average fair value per share of options granted with exercise prices at fair market value	

The following table summarizes additional information about stock options during 2008, 2007 and 2006:

	2008	2007	2006
	(In millions)		
Stock Option Expense Recognized	**$ 11.0**	$ 15.1	$ 6.7
Stock Options Exercised:			
Cash Received for Exercise Price	**20.2**	43.4	35.5
Intrinsic Value Realized by Employee	**14.1**	67.6	27.6
Realized Tax Benefit	**5.7**	26.7	10.9
Fair Value of Shares that Vested	**98.3**	82.7	82.6

As of December 31, 2008, we had $7.8 million of unrecognized compensation cost related to the unvested portion of outstanding stock option awards, of which $6.2 million is expected to be recognized during 2009.

The following table summarizes additional information about stock options outstanding at December 31, 2008 (stock options in thousands):

Range of Exercise Prices		Outstanding Stock Options	Outstanding Aggregate Intrinsic Value *	Exercisable Stock Options	Exercisable Aggregate Intrinsic Value *	Weighted-Average Remaining Contractual Life
			(In millions)		(In millions)	(In years)
$20.00	$ 40.00	1,217	$	1,217	$	3.9
$40.00	$ 60.00	3,004		3,004		3.8
$60.00	$ 80.00	1,000		430		6.7
$80.00	$100.00	837		14		8.6
		6,058	$	4,665	$	

*

No stock options are currently outstanding with an exercise price below Constellation Energy's stock price at December 31, 2008.

Restricted Stock Awards

In addition to stock options, we issue common stock based on meeting certain service goals. This stock vests to participants at various times ranging from one to five years if the service goals are met. In accordance with SFAS No. 123R, we account for our service-based awards as equity awards, whereby we recognize the value of the market price of the underlying stock on the date of grant to compensation expense over the service period either ratably or in tranches (depending if the award has cliff or graded vesting).

We recorded compensation expense related to our restricted stock awards of $46.6 million in 2008, $35.8 million in 2007, and $24.5 million in 2006. The tax benefits received associated with our restricted awards were $20.1 million in 2008, $17.6 million in 2007, and $10.9 million in 2006. Summarized share information for our restricted stock awards is as follows:

	2008	2007	2006
	(Shares in thousands)		
Outstanding, beginning of year	**1,322**	1,207	1,272
Granted	**365**	710	511
Released to participants	**(536)**	(552)	(502)
Canceled	**(118)**	(43)	(74)
Outstanding, end of year	**1,033**	1,322	1,207
Weighted-average fair value of restricted stock granted (per share)	**$ 94.62**	$ 75.29	$ 58.68

Total fair value of shares for which restriction has lapsed (in millions)	**$ 49.7**	$ 44.5	$ 27.6

As of December 31, 2008, we had $22.9 million of unrecognized compensation cost related to the unvested portion of outstanding restricted stock awards expected to be recognized within a 39-month period. At December 31, 2008, we have recorded in "Common shareholders' equity" approximately $47.8 million and approximately $42.3 million at December 31, 2007 for the unvested portion of service-based restricted stock granted from 2006 until 2008 to officers and other employees that is contingently redeemable in cash upon a change in control.

Performance-Based Units

In accordance with SFAS No. 123R, we recognize compensation expense ratably for our performance-based awards, which are classified as liability awards, for which the fair value of the award is remeasured at each reporting period. Each unit is equivalent to $1 in value and cliff vests at the end of a three-year service and performance period. The level of payout is based on the achievement of certain performance goals at the end of the three-year period and will be settled in cash. In 2008, we recorded a reduction of compensation expense of $3.2 million due to lower anticipated achievement. We reported compensation expense of $17.6 million in 2007, and $24.0 million in 2006 for these awards. During the 12 months ended December 31, 2008, our 2005 performance-based unit award vested and we paid $24.2 million in cash to settle the award. During the 12 months ended December 31, 2007, our 2004 performance-based unit award vested and we paid $19.7 million in cash to settle the award. As of December 31, 2008 we had $3.7 million of unrecognized compensation cost related to the unvested portion of outstanding performance-based unit awards expected to be recognized within a 26-month period.

Equity-Based Grants

We recorded compensation expense of $0.9 million in 2008, $0.9 million in 2007, and $0.6 million in 2006 related to equity-based grants to members of the Board of Directors.

15 Merger and Acquisitions

Investment Agreement with EDF Group

On December 17, 2008, we entered into an Investment Agreement with 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).

In connection with this transaction, we issued 10,000 shares of 8% Series B Preferred Stock to EDF for an aggregate value of $1 billion. This $1 billion will be subsequently credited against the $4.5 billion purchase price for EDF's membership interest at the time of closing. At that time, EDF will surrender all of the shares of Series B Preferred Stock to us. We discuss the 8% Series B Preferred Stock in more detail in *Note 9*.

The Investment Agreement also includes an asset put arrangement that provides us with additional liquidity of up to $2 billion. Pursuant to the put arrangement, we can exercise an option through December 31, 2010 (or the termination of the Investment Agreement by EDF due to our breach of the Investment Agreement), to require EDF to acquire certain non-nuclear generation assets. The execution of this put arrangement is subject to regulatory approval. We discuss this facility in more detail in *Note 8*.

In connection with these transactions, EDF has reimbursed us $150 million for transaction costs, which is in addition to the purchase price, has agreed to make certain other payments, and has also provided us with a $600 million interim backstop liquidity facility. We discuss this facility in more detail in *Note 8*.

Prior to closing, we will transfer to our nuclear generation and operation business transactions with a negative mark-to-market value not to exceed $700 million in the aggregate using a 10% discount rate. This transfer will occur in a manner that is to be determined and to be mutually acceptable to Constellation Energy and EDF.

Constellation Energy and EDF are working to close the Investment Agreement in the third quarter of 2009. The Investment Agreement contains certain termination rights for both Constellation Energy and EDF. If the Investment Agreement is terminated for a failure of the closing to occur after all regulatory approvals have been obtained, EDF will be required to pay Constellation Energy a termination fee of $175 million.

In addition, if the Investment Agreement is terminated, the Series B Preferred Stock will be redeemed at the later of the date of termination or December 31, 2009 for $1 billion aggregate principal amount of 10% Senior Notes of Constellation Energy due June 30, 2010.

We have agreed that the maximum aggregate liability of EDF for losses or damages in connection with the Investment Agreement would be limited to $1.5 billion. Our recourse for the first $1 billion in losses or damages is limited to the Series B Preferred Stock or if the Series B Preferred Stock has been redeemed, the 10% Senior Notes or any cash received upon redemption.

Termination of Merger Agreement with MidAmerican

On December 17, 2008 Constellation Energy and MidAmerican agreed to terminate the Agreement and Plan of Merger the parties entered into on September 19, 2008.

In connection with the termination and conversion of our Series A Preferred Stock, we made certain payments and issued certain securities to MidAmerican. Specifically, we:

- paid MidAmerican the $175 million merger termination fee,
- paid MidAmerican approximately $418 million in lieu of the number of shares of our common stock (valued at $26.50 per share) that were due to MidAmerican on the conversion of Series A Preferred Stock but that could not be issued due to regulatory limitations,
- issued and delivered a total of 19,897,322 shares of our common stock, representing 9.99% of our total outstanding common shares (after giving effect to the issuance, due upon conversion of the Series A Preferred Stock), the fair value of the common stock on the date of issuance was estimated to be $572.6 million based on the stock price at the time of issuance, and

delivered to MidAmerican 14% Senior Notes in the aggregate principal amount of $1.0 billion, also issued upon the conversion of the Series A Preferred Stock.

We discuss the merger termination fee in more detail in *Note 2*. We discuss the conversion of the Series A Preferred Stock into cash, our common shares and 14% Senior Notes in more detail in *Note 9*.

Nufcor International Limited

On June 26, 2008, we acquired Nufcor International Limited (Nufcor). We include Nufcor as part of our Global Commodities operations in our merchant energy business segment and have included its results of operations in our consolidated financial statements since the date of acquisition. Nufcor is a uranium market participant that provides marketing services to uranium producers, utilities and an investment fund in the North American and European markets.

We acquired 100% ownership of Nufcor for $102.8 million, including direct costs, of which $104.9 million was paid in cash at closing. Subsequent to closing, we received $3.1 million back from the seller as a result of adjustments to Nufcor's net assets. As part of the purchase, we acquired $37.3 million in cash.

Our final purchase price allocation related to Nufcor is as follows:

At June 26, 2008

	(In millions)
Cash	$ 37.3
Fuel stocks	126.8
Other current assets	8.5
Total current assets	172.6
Goodwill (1)(2)	6.3
Other assets	30.4
Total assets acquired	209.3
Short-term borrowings	(28.0)
Unamortized energy contract liabilities	(15.8)
Other current liabilities	(29.7)
Total current liabilities	(73.5)
Unamortized energy contract liabilities	(33.0)
Total liabilities	(106.5)
Net assets acquired	$ 102.8

(1) *Not deductible for tax purposes.*

(2) *Amount has been subsequently charged to expense as part of our merchant energy goodwill impairment charge recorded during 2008.*

The pro-forma impact of the Nufcor acquisition would not have been material to our results of operations for the years ended December 31, 2008, 2007, and 2006.

West Valley Power Plant

On June 1, 2008, we acquired the West Valley Power Plant, a 200 MW gas-fired peaking plant located in Utah for approximately $88.6 million (including direct costs). We accounted for this transaction as an asset acquisition and have included this plant's results of operations in the Generation operations of our merchant energy business segment since the date of acquisition. We allocated the purchase price primarily to the equipment with lesser amounts allocated to land and spare parts inventory.

Hillabee Energy Center

On February 14, 2008, we acquired the Hillabee Energy Center, a partially completed 774 MW gas-fired combined cycle power generation facility located in Alabama for $156.9 million (including direct costs), which we accounted for as an asset acquisition. We allocated the purchase price primarily to the equipment with lesser amounts allocated to land and contracts acquired. We plan to complete the construction of this facility and expect it to be ready for commercial operation in late 2009.

Cornerstone Energy

On July 1, 2007, we acquired Cornerstone Energy, Inc. (CEI). We include CEI, part of our retail competitive supply operation, in our merchant energy business segment and have included its results of operations in our consolidated financial statements since the date of acquisition. CEI provides natural gas supply and related services to commercial, industrial and institutional customers across the central United States. CEI is expected to add approximately 100 billion cubic feet of natural gas to our annual volumes served.

We acquired 100% ownership for $108.3 million, which we paid in cash. As part of the purchase, we acquired $7.3 million in cash.

The total consideration for accounting purposes, consisting of cash and other noncash consideration, including the fair value of certain preexisting contracts with CEI, was equal to $137.6 million.

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

At July 1, 2007

	(In millions)
Cash	$ 7.3
Other Current Assets	89.6
Total Current Assets	96.9
Goodwill (1)(2)	103.4
Net Property, Plant and Equipment	0.5
Other Assets	6.7
Total Assets Acquired	207.5
Current Liabilities	(66.3)
Deferred Credits and Other Liabilities	(3.6)
Total Liabilities	(69.9)
Net Assets Acquired	$ 137.6

(1) *Approximately $99 million is deductible for tax purposes.*

(2) *Amount has been subsequently charged to expense as part of our merchant energy goodwill impairment charge recorded during 2008.*

The pro-forma impact of the CEI acquisition would not have been material to our results of operations for the years ended December 31, 2007 and 2006.

Acquisitions of Working Interests in Gas Producing Fields

In 2007, we acquired working interests of 41% and 55% in two gas and oil producing properties in Oklahoma for $208.9 million, subject to closing adjustments. We purchased leases, producing wells, inventory, and related equipment. We have included the results of operations from these properties in our merchant energy business segment since the date of acquisition.

Our purchase price was allocated to the net assets acquired as follows:

At March 23, 2007

	(In millions)
Property, Plant and Equipment	
Inventory	$ 0.2
Unproved property	28.8
Proved property	179.9
Net Assets Acquired	$ 208.9

The pro-forma impact of the acquisition of these working interests would not have been material to our results of operations for the years ended December 31, 2007 and 2006.

16 Related Party Transactions

Constellation Energy

On March 31, 2008, our merchant energy business sold its working interest in 83 oil and natural gas producing wells in Oklahoma to CEP, an equity method investment of Constellation Energy, for total proceeds of approximately $53 million. Our merchant energy business recognized a $14.3 million gain, net of the minority interest gain of $0.7 million on the sale and exclusive of our 28.5% ownership interest in CEP. This gain is recorded in "Gains on Sales of Assets" in our Consolidated Statements of Income (Loss).

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 residential electric customers through May 31, 2011.

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

Year Ended December 31,	**2008**	**2007**	**2006**
		(In millions)	
Electricity purchased for resale expenses	**$ 802.0**	$ 1,139.6	$ 1,062.0

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

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

Year ended December 31,	**2008**	**2007**	**2006**
		(In millions)	
Charges to BGE	**$ 153.6**	$ 160.8	$ 148.8

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 $148.8 million at December 31, 2008 and $78.4 million at December 31, 2007.

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

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

17 Quarterly Financial Data (Unaudited)

Our quarterly financial information has not been audited but, in management's opinion, includes all adjustments necessary for a fair statement. Our business is seasonal in nature with the peak sales periods generally occurring during the summer and winter months. Accordingly, comparisons among quarters of a year may not represent overall trends and changes in operations.

2008 Quarterly Data Constellation Energy

	Revenues	Income (Loss) from Operations	Income (Loss) from Continuing Operations	Income (Loss) Applicable to Common Stock	Earnings (Loss) Per Share from Continuing Operations Diluted	Earnings (Loss) Per Share of Common Stock Diluted
	(In millions, except per share amounts)					
Quarter Ended						
March 31	**$ 4,812.2**	**$ 254.3**	**$ 145.7**	**$ 145.7**	**$ 0.81**	**$ 0.81**
June 30	**4,756.1**	**331.7**	**171.5**	**171.5**	**0.95**	**0.95**
September 30	**5,323.6**	**(228.4)**	**(225.7)**	**(225.7)**	**(1.27)**	**(1.27)**
December 31	**4,926.4**	**(1,335.7)**	**(1,405.9)**	**(1,405.9)**	**(7.75)**	**(7.75)**
Year Ended						
December 31	**$ 19,818.3**	**$ (978.1)**	**$ (1,314.4)**	**$ (1,314.4)**	**$ (7.34)**	**$ (7.34)**

2008 Quarterly Data BGE

	Revenues	Income (Loss) from Operations	Earnings (Loss) Applicable to Common Stock
	(In millions)		
Quarter Ended			
March 31	**$ 1,105.8**	**$ 137.7**	**$ 73.0**
June 30	**636.8**	**(131.1)**	**(107.4)**
September 30	**977.9**	**69.6**	**19.9**
December 31	**983.2**	**106.3**	**52.8**
Year Ended			
December 31	**$ 3,703.7**	**$ 182.5**	**$ 38.3**

The sum of the quarterly earnings per share amounts may not equal the total for the year due to the effects of rounding and dilution as a result of issuing common shares during the year. Constellation Energy revenues for the quarter ended March 31, 2008 and June 30, 2008 have been reclassified to conform with the current presentation.

First quarter results include:

- a $3.9 million after-tax charge for the impairment of certain of our nuclear decommissioning trust fund investments,
- a $6.6 million tax benefit related to the anticipated finalization of the Maryland settlement agreement, and
- a $9.1 million after-tax gain on the sale of certain working interests in an upstream gas property.

Second quarter results include:

- a $2.4 million after-tax charge for the impairment of certain of our nuclear decommissioning trust fund investments,
- a $13.4 million after-tax charge related to the write-down of our emission allowance inventory,
- a $125.3 million after-tax charge related to the one-time $170 residential electric customer credit related to the Maryland settlement agreement,
- a $2.1 million tax benefit related to the Maryland settlement agreement, and
- a $46.2 million after-tax gain on the sale of certain working interests in upstream gas properties.

Third quarter results include:

- a $169.1 million after-tax charge for the impairment of goodwill,
- a $86.6 million after-tax charge for the impairments of certain of our upstream gas properties,

a $34.2 million after-tax charge for the impairment of our investment in CEP LLC,

a $22.8 million after-tax charge related to the write-down of our emission allowance inventory,

a $15.3 million after-tax charge for the impairment of certain of our nuclear decommissioning trust fund investments,

a $18.9 million after-tax gain on the sale of a dry bulk vessel in our shipping joint venture,

merger and strategic alternatives costs totaling $37.3 million after-tax, of which BGE recorded $10.6 million after-tax,

estimated settlement costs totaling $8.9 million after-tax related to a class action complaint alleging ash placement at a third party site damaged surrounding properties,

workforce reduction costs totaling $1.6 million after-tax related to our Customer Supply operations, and

a $2.0 million tax benefit related to the Maryland settlement agreement.

Fourth quarter results include:

a $119.8 million after-tax charge for the impairments of certain of our upstream gas properties,

a $50.6 million loss after-tax for an impairment of our investment in CEP LLC and a marketable security held by our Global Commodities operations,

a $7.5 million after-tax gain related to the recovery in the value of our emission allowance inventory,

a $60.4 million after-tax charge for the impairment of certain of our nuclear decommissioning trust fund investments, a $39.3 million after-tax loss on the sale of certain upstream gas properties,

merger termination and strategic alternatives costs totaling $1,167.1 million after-tax, of which BGE recorded a cost reduction of $10.6 million after-tax associated with the re-allocation of costs prior to EDF transaction to our merchant energy segment,

workforce reduction costs totaling $11.8 million after-tax related to our company-wide reduction in force,

a $0.6 after-tax benefit for an adjustment to the estimated settlement costs relating to the class action ash placement complaint,

a $2.1 million after-tax charge for an adjustment to the impairment of goodwill,

a $1.2 million loss after-tax related to a final true-up of the one-time $170 residential electric customer credit related to the Maryland settlement agreement, and

a $5.3 million tax benefit related to the Maryland settlement agreement.

We discuss these items in *Note 2*.

2007 Quarterly Data Constellation Energy

	Revenues	Income from Operations	Income from Continuing Operations	Earnings Applicable to Common Stock	Earnings Per Share from Continuing Operations Diluted	Earnings Per Share of Common Stock Diluted
	(In millions, except per share amounts)					
Quarter Ended						
March 31	$ 5,111.1	$ 302.4	$ 197.3	$ 195.7	$ 1.08	$ 1.07
June 30	4,876.3	154.4	116.3	116.3	0.64	0.64
September 30	5,856.4	425.1	250.7	251.4	1.37	1.38
December 31	5,349.4	452.5	258.1	258.1	1.42	1.42
Year Ended						
December 31	$21,193.2	$ 1,334.4	$ 822.4	$ 821.5	$ 4.51	$ 4.50

2007 Quarterly Data BGE

	Revenues	Income from Operations	Earnings Applicable to Common Stock
	(In millions)		
Quarter Ended			
March 31	$ 922.1	$ 136.0	$ 66.0
June 30	707.1	50.5	13.6
September 30	896.9	66.5	24.4
December 31	892.4	81.3	22.6
Year Ended			
December 31	$ 3,418.5	$ 334.3	$ 126.6

The sum of the quarterly earnings per share amounts may not equal the total for the year due to the effects of rounding and dilution as a result of issuing common shares during the year. Constellation Energy revenues for the quarter ended March 31, 2007 and June 30, 2007 have been reclassified to conform with the current presentation.

First quarter results include:

a $1.6 million loss after-tax for the discontinued operations of our High Desert Facility.

Second quarter results include:

a $8.0 million gain after-tax on sales of equity of CEP,

a $12.2 million charge after-tax related to a cancelled wind development project, and

workforce reduction costs totaling $1.4 million after-tax.

Third quarter results include:

- a $24.3 million gain after-tax on sales of equity of CEP, and
- a $0.6 million loss after-tax for the discontinued operations of our Hawaiian geothermal facility, and
- a $1.3 million gain after-tax for the discontinued operations of our High Desert Facility.

Fourth quarter results include:

- a $6.9 million gain after-tax on sales of equity of CEP.

We discuss these items in *Note 2*.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Items 9A and 9A(T). Controls and Procedures

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 December 31, 2008 (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.

Internal Control Over Financial Reporting

Each of Constellation Energy and BGE maintains a system of internal control over financial reporting as defined in Exchange Act Rule 13a-15(f). The Management's Reports on Internal Control Over Financial Reporting of each of Constellation Energy and BGE are included in *Item 8. Financial Statements and Supplementary Data* included in this report. As BGE is not an accelerated filer as defined in Exchange Act Rule 12b-2, its Management's Report on Internal Control Over Financial Reporting is not deemed to be filed for purposes of Section 18 of the Exchange Act as permitted by the rules and regulations of the Securities and Exchange Commission.

Changes in Internal Control

During the quarter ended December 31, 2008, 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.

Item 9B. Other Information

None.

PART III

BGE meets the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K for a reduced disclosure format. Accordingly, all items in this section related to BGE are not presented.

Item 10. Directors and Executive Officers of the Registrant

The information required by this item with respect to directors will be set forth under *Election of Directors* in the Proxy Statement and incorporated herein by reference.

The information required by this item with respect to executive officers of Constellation Energy Group, pursuant to instruction 3 of paragraph (b) of Item 401 of Regulation S-K, is set forth following Item 4 of Part I of this Form 10-K under *Executive Officers of the Registrant*.

Item 11. Executive Compensation

The information required by this item will be set forth under *Executive and Director Compensation* and *Report of Compensation Committee* in the Proxy Statement and incorporated herein by reference.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Shareholder Matters

The additional information required by this item will be set forth under *Stock Ownership* in the Proxy Statement and incorporated herein by reference.

Equity Compensation Plan Information

The following table reflects our equity compensation plan information as of December 31, 2008:

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants, and rights	(b) Weighted-average exercise price of outstanding options, warrants, and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in item (a))
	(In thousands)		*(In thousands)*
Equity compensation plans approved by security holders	5,220	$ 62.79	8,730
Equity compensation plans not approved by security holders	838	$ 42.56	
Total	6,058	$ 59.99	8,730

The plans that do not require shareholder approval are the Constellation Energy Group, Inc. 2002 Senior Management Long-Term Incentive Plan (Designated as Exhibit No. 10(m)) and the Constellation Energy Group, Inc. Management Long-Term Incentive Plan (Designated as Exhibit No. 10(n)). A brief description of the material features of each of these plans is set forth below.

2002 Senior Management Long-Term Incentive Plan

The 2002 Senior Management Long-Term Incentive Plan became effective May 24, 2002 and authorized the issuance of up to 4,000,000 shares of Constellation Energy common stock in connection with the grant of equity awards. No further awards will be made under this plan. Any shares covered by an outstanding award that is forfeited or cancelled, expires or is settled in cash will become available for issuance under the shareholder-approved 2007 Long-Term Incentive Plan. Shares delivered pursuant to awards under this plan may be authorized and unissued shares or shares purchased on the open market in accordance with the applicable securities laws. Restricted stock, restricted stock unit, and performance unit award payouts will be accelerated and stock options and stock appreciation rights gains will be paid in cash in the event of a change in control, as defined in the plan. The plan is administered by Constellation Energy's Chief Executive Officer.

Management Long-Term Incentive Plan

The Management Long-Term Incentive Plan became effective February 1, 1998 and authorized the issuance of up to 3,000,000 shares of Constellation Energy common stock in connection with the grant of equity awards. No further awards will be made under this plan. Any shares covered by an outstanding award that is forfeited or cancelled, expires or is settled in cash will become available for issuance under the shareholder-approved 2007 Long-Term Incentive Plan. Shares delivered pursuant to awards under the plan may be authorized and unissued shares or shares purchased on the open market in accordance with applicable securities laws. Restricted stock, restricted stock units, and performance unit award payouts will be accelerated and stock options and stock appreciation rights will become fully exercisable in the event of a change in control, as defined by the plan. The plan is administered by Constellation Energy's Chief Executive Officer.

Item 13. Certain Relationships and Related Transactions, and Director Independence

The additional information required by this item will be set forth under *Related Persons Transactions* and *Determination of Independence* in the Proxy Statement and incorporated herein by reference.

Item 14. Principal Accountant Fees and Services

The information required by this item will be set forth under *Ratification of PricewaterhouseCoopers LLP as Independent Registered Public Accounting Firm for 2009* in the Proxy Statement and incorporated herein by reference.

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PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) The following documents are filed as a part of this Report:

1. Financial Statements:
   Reports of Independent Registered Public Accounting Firm dated February 27, 2009 of PricewaterhouseCoopers LLP
   Consolidated Statements of Income (Loss) Constellation Energy Group for three years ended December 31, 2008
   Consolidated Balance Sheets Constellation Energy Group at December 31, 2008 and December 31, 2007
   Consolidated Statements of Cash Flows Constellation Energy Group for three years ended December 31, 2008
   Consolidated Statements of Common Shareholders' Equity and Comprehensive Income Constellation Energy Group for three years ended December 31, 2008
   Consolidated Statements of Income Baltimore Gas and Electric Company for three years ended December 31, 2008
   Consolidated Balance Sheets Baltimore Gas and Electric Company at December 31, 2008 and December 31, 2007
   Consolidated Statements of Cash Flows Baltimore Gas and Electric Company for three years ended December 31, 2008
   Notes to Consolidated Financial Statements
2. Financial Statement Schedules:
   Schedule II Valuation and Qualifying Accounts
   Schedules other than Schedule II are omitted as not applicable or not required.
3. Exhibits Required by Item 601 of Regulation S-K.

Exhibit Number	
*2	Agreement and Plan of Share Exchange between Baltimore Gas and Electric Company and Constellation Energy Group, Inc. dated as of February 19, 1999. (Designated as Exhibit No. 2 to the Registration Statement on Form S-4 dated March 3, 1999, File No. 33-64799.)
*2(a)	Agreement and Plan of Reorganization and Corporate Separation (Nuclear). (Designated as Exhibit No. 2(a) to the Current Report on Form 8-K dated July 7, 2000, File Nos. 1-12869 and 1-1910.)
*2(b)	Agreement and Plan of Reorganization and Corporate Separation (Fossil). (Designated as Exhibit No. 2(b) to the Current Report on Form 8-K dated July 7, 2000, File Nos. 1-12869 and 1-1910.)
*2(c)	Termination Agreement, dated December 17, 2008, by and among Constellation Energy Group, Inc., Constellation Generation II, LLC, Constellation Power Source Generation, Inc., MidAmerican Energy Holdings Company, MEHC Merger Sub Inc., MEHC Investment, Inc. and Electricite de France International S.A. (Designated as Exhibit 2.1 to the Current Report on Form 8-K dated December 17, 2008, File No. 1-12869.)
*2(d)	Master Put Option and Membership Interest Purchase Agreement, dated as of December 17, 2008, by and among Constellation Energy Group, Inc., EDF Development, Inc. and Electricite de France International, S.A. (Designated as Exhibit No. 21 to the Current Report on Form 8-K dated December 17, 2008, File No. 1-12869.)
*3(a)	Articles Supplementary to the Charter of Constellation Energy Group, Inc. as of December 17, 2008. (Designated as Exhibit No. 3.1 to the Current Report on Form 8-K dated December 17, 2008, File No. 1-12869.)
*3(b)	Articles Supplementary to the Charter of Constellation Energy Group, Inc. as of September 19, 2008. (Designated as Exhibit No. 3.1 to the Current Report on Form 8-K dated September 19, 2008, File No. 1-12869.)
3(c)	

Certificate of Correction to Articles Supplementary to the Charter of Constellation Energy Group, Inc. as of November 25, 2008.

*3(d)	Articles of Amendment to the Charter of Constellation Energy Group, Inc. as of July 21, 2008. (Designated as Exhibit No. 3(a) to the Quarterly Report on Form 10-Q dated June 30, 2008, File Nos. 1-12869 and 1-1910.)
*3(e)	Articles Supplementary to the Charter of Constellation Energy Group, Inc. as of April 10, 2007. (Designated as Exhibit 3(a) to the Current Report on Form 8-K dated April 10, 2007, File No. 1-12869.)
*3(f)	Articles Supplementary to the Charter of Constellation Energy Group, Inc. as of November 20, 2001. (Designated as Exhibit No. 3(e) to the Annual Report on Form 10-K for the year ended December 31, 2001, File Nos. 1-12869 and 1-1910.)
*3(g)	Certificate of Correction to the Charter of Constellation Energy Group, Inc. as of September 13, 1999. (Designated as Exhibit No. 3(c) to the Annual Report on Form 10-K for the year ended December 31, 1999, File Nos. 1-12869 and 1-1910.)
*3(h)	Articles Supplementary to the Charter of Constellation Energy Group, Inc., as of July 19, 1999. (Designated as Exhibit No. 3(a) to the Quarterly Report on Form 10-Q for the quarter ended June 30, 1999, File Nos. 1-12869 and 1-1910.)
*3(i)	Articles of Amendment and Restatement of Constellation Energy Group, Inc. as of April 30, 1999. (Designated as Appendix B to Post-Effective Amendment No. 1 to the Registration Statement on Form S-4 filed March 3, 1999, File No. 33-64799.)
*3(j)	Bylaws of Constellation Energy Group, Inc., as amended to July 18, 2008. (Designated as Exhibit No. 3 to the Current Report on Form 8-K dated July 18, 2008, File No. 1-12869.)
*3(k)	Charter of BGE, restated as of August 16, 1996. (Designated as Exhibit No. 3 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 1996, File No. 1-1910.)
*3(l)	Bylaws of BGE, as amended to October 16, 1998. (Designated as Exhibit No. 3 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 1998, File No. 1-1910.)
*4(a)	Indenture between Constellation Energy Group, Inc. and the Bank of New York, Trustee dated as of March 24, 1999. (Designated as Exhibit No. 4(a) to the Registration Statement on Form S-3 dated March 29, 1999, File No. 333-75217.)
*4(b)	First Supplemental Indenture between Constellation Energy Group, Inc. and the Bank of New York, Trustee dated as of January 24, 2003. (Designated as Exhibit No. 4(b) to the Registration Statement on Form S-3 dated January 24, 2003, File No. 333-102723.)
*4(c)	Indenture dated June 19, 2008 between Constellation Energy Group, Inc. and Deutsche Bank Trust Company Americas, as trustee. (Designated as Exhibit No. 4(a) to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2008, File Nos. 1-12869 and 1-1910.)
*4(d)	Indenture dated July 1, 1985, between BGE and The Bank of New York (Successor to Mercantile-Safe Deposit and Trust Company), Trustee. (Designated as Exhibit 4(a) to the Registration Statement on Form S-3, File No. 2-98443); as supplemented by Supplemental Indentures dated as of October 1, 1987 (Designated as Exhibit 4(a) to the Current Report on Form 8-K, dated November 13, 1987, File No. 1-1910) and as of January 26, 1993 (Designated as Exhibit 4(b) to the Current Report on Form 8-K, dated January 29, 1993, File No. 1-1910.)
*4(e)	Form of Subordinated Indenture between the Company and The Bank of New York, as Trustee in connection with the issuance of the Junior Subordinated Debentures. (Designated as Exhibit 4(d) to the Registration Statement on Form S-3 dated August 5, 2003, File No. 333-107681.)
*4(f)	Form of Supplemental Indenture between the Company and The Bank of New York, as Trustee in connection with the issuances of the Junior Subordinated Debentures. (Designated as Exhibit 4(e) to the Registration Statement on Form S-3 dated August 5, 2003, File No. 333-107681.)
*4(g)	Form of Preferred Securities Guarantee (Designated as Exhibit 4(f) to the Registration Statement on Form S-3 dated August 5, 2003, File No. 333-107681.)
*4(h)	Form of Junior Subordinated Debenture (Designated as Exhibit 4(h) to the Registration Statement on Form S-3 dated August 5, 2003, File No. 333-107681.)
*4(i)	Form of Amended and Restated Declaration of Trust (including Form of Preferred Security) (Designated as Exhibit 4(c) to the Registration Statement on Form S-3 dated August 5, 2003, File No. 333-107681.)

*4(j)	Indenture dated as of July 24, 2006 between Constellation Energy Group, Inc. and Deutsche Bank Trust Company Americas, as trustee. (Designated as Exhibit 4(a) to the Registration Statement on Form S-3 filed July 24, 2006, File No. 333-135991.)
*4(k)	First Supplemental Indenture between Constellation Energy Group, Inc. and Deutsche Bank Trust Company Americas, as trustee, dated as of June 27, 2008. (Designated as Exhibit No. 4(a) to the Current Report on Form 8-K dated June 30, 2008, File No. 1-12869.)
*4(l)	Indenture dated as of July 24, 2006 between Baltimore Gas and Electric Company and Deutsche Bank Trust Company Americas, as trustee. (Designated as Exhibit 4(b) to the Registration Statement on Form S-3 filed July 24, 2006, File No. 333-135991.)
*4(m)	First Supplemental Indenture between Baltimore Gas and Electric Company and Deutsche Bank Trust Company Americas, as trustee, dated as of October 13, 2006. (Designated as Exhibit 4(a) to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2006, File Nos. 1-12869 and 1-1910.)
*4(n)	Indenture dated as of June 29, 2007, by and between RSB BondCo LLC and Deutsche Bank Trust Company Americas, as Trustee and Securities Intermediary. (Designated as Exhibit 4.1 to the Current Report on Form 8-K dated July 5, 2007, File No. 1-1910.)
*4(o)	Series Supplement to Indenture dated as of June 29, 2007 by and between RSB BondCo LLC and Deutsche Bank Trust Company Americas, as Trustee and Securities Intermediary (Designated as Exhibit 4.2 to the Current Report on Form 8-K dated July 5, 2007, File No. 1-1910.)
*4(p)	Replacement Capital Covenant dated June 27, 2008. (Designated as Exhibit No. 4(b) to the Current Report on Form 8-K dated June 30, 2008, File No. 1-12869.)
+*10(a)	Executive Annual Incentive Plan of Constellation Energy Group, Inc., as amended and restated. (Designated as Exhibit No. 10(d) to the Quarterly Report on Form 10-Q for the quarter ended September30, 2008, File Nos. 1-12869 and 1-1910.)
+10(b)	Constellation Energy Group, Inc. Nonqualified Deferred Compensation Plan, as amended and restated.
10(c)	Constellation Energy Group, Inc. Deferred Compensation Plan for Non-Employee Directors, as amended and restated.
+10(d)	Constellation Energy Group, Inc. Benefits Restoration Plan, as amended and restated.
+10(e)	Constellation Energy Group, Inc. Supplemental Pension Plan, as amended and restated.
+10(f)	Constellation Energy Group, Inc. Senior Executive Supplemental Plan, as amended and restated.
+*10(g)	Constellation Energy Group, Inc. Supplemental Benefits Plan, as amended and restated. (Designated as Exhibit No. 10(a) to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2008, File Nos. 1-12869 and 1-1910.)
+10(h)	Second amended and restated change in control severance agreement between Constellation Energy Group, Inc. and Mayo A. Shattuck III.
+10(i)	Second amended and restated change in control severance agreement between Constellation Energy Group, Inc. and John R. Collins.
+*10(j)	Constellation Energy Group, Inc. 1995 Long-Term Incentive Plan, as amended and restated. (Designated as Exhibit No. 10(b) to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2004, File Nos. 1-12869 and 1-1910.)
+*10(k)	Constellation Energy Group, Inc. Executive Long-Term Incentive Plan, as amended and restated. (Designated as Exhibit 10(b) to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2006, File Nos. 1-12869 and 1-1910.)
+*10(l)	Constellation Energy Group, Inc. 2002 Executive Annual Incentive Plan, as amended and restated. (Designated as Exhibit 10(o) to the Annual Report on Form 10-K for the year ended December 31, 2006, File Nos. 1-12869 and 1-1910.)
+*10(m)	Constellation Energy Group, Inc. 2002 Senior Management Long-Term Incentive Plan, as amended and restated. (Designated as Exhibit 10(c) to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2006, File Nos. 1-12869 and 1-1910.)

+*10(n)	Constellation Energy Group, Inc. Management Long-Term Incentive Plan, as amended and restated. (Designated as Exhibit 10(d) to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2006, File Nos. 1-12869 and 1-1910.)
+*10(o)	Constellation Energy Group, Inc. 2007 Long-Term Incentive Plan, as amended and restated. (Designated as Exhibit 10(a) to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2008, File Nos. 1-12869 and 1-1910.)
*10(p)	Grantor Trust Agreement Dated as of February 27, 2004 between Constellation Energy Group, Inc. and Citibank, N.A. (Designated as Exhibit No. 10(d) to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2004, File Nos. 1-12869 and 1-1910.)
*10(q)	Grantor Trust Agreement dated as of February 27, 2004 between Constellation Energy Group, Inc. and T. Rowe Price Trust Company. (Designated as Exhibit No. 10(b) to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2004, File Nos. 1-12869 and 1-1910.)
*10(r)	Rate Stabilization Property Servicing Agreement dated as of June 29, 2007 by and between RSB BondCo LLC and Baltimore Gas and Electric Company, as servicer (Designated as Exhibit 10.2 to the Current Report on Form 8-K dated July 5, 2007, File No. 1-1910.)
*10(s)	Administration Agreement dated as of June 29, 2007 by and between RSB BondCo LLC and Baltimore Gas and Electric Company, as administrator (Designated as Exhibit 10.3 to the Current Report on Form 8-K dated July 5, 2007, File No. 1-1910.)
*10(t)	Investor Rights Agreement, dated as of September 19, 2008, by and between Constellation Energy Group, Inc. and MidAmerican Energy Holdings Company. (Designated as Exhibit No. 10.3 to the Current Report on Form 8-K dated September 19, 2008, File No. 1-12869.)
*10(u)	Letter Agreement, dated December 17, 2008, by and among Constellation Energy Group, Inc., MidAmerican Energy Holdings Company, MEHC Merger Sub Inc. and MEHC Investment, Inc. (Designated as Exhibit No. 10.1 to the Current Report on Form 8-K dated December 17, 2008, File No. 1-12869.)
*10(v)	Form of CENG Operating Agreement (Designated as Exhibit No. 10.1 to the Current Report on Form 8-K dated December 17, 2008, File No. 1-12869.)
*10(w)	Stock Purchase Agreement, dated as of December 17, 2008, by and among Constellation Energy Group, Inc., EDF Development, Inc. and Electricite de France International, S.A. (Designated as Exhibit No. 10.2 to the Current Report on Form 8-K dated December 17, 2008, File No. 1-12869.)
*10(x)	Investor Rights Agreement, dated as of December 17, 2008, by and between Constellation Energy Group, Inc. and EDF Development, Inc. (Designated as Exhibit No. 10.3 to the Current Report on Form 8-K dated December 17, 2008, File No. 1-12869.)
*10(y)	Payment Guaranty, dated as of December 17, 2008, by and between Constellation Energy Group, Inc. and Electricite de France, S.A. (Designated as Exhibit No. 10.4 to the Current Report on Form 8-K dated December 17, 2008, File No. 1-12869.)
*10(z)	Amended and Restated Investor Agreement, dated December 17, 2008, by and between Constellation Energy Group, Inc. and Electricite de France International, SA (Designated as Exhibit 10.7 to the Current Report on Form 8-K dated December 17, 2008, File No. 1-12869.)
*10(aa)	Amended and Restated Credit Agreement, dated as of December 17, 2008, among Constellation Energy Group, Inc., the Lenders named therein and the Royal Bank of Scotland PLC, as Administrative Agent. (Designated as Exhibit No. 10.5 to the Current Report on Form 8-K dated December 17, 2008, File No. 1-12869.)
*10(bb)	Second Amended and Restated Credit Agreement, dated as of December 17, 2008, among Constellation Energy Group, Inc., the Lenders named therein, Wachovia Bank, National Association, as Administrative Agent, LC Bank, Swingline Lender and Collateral Agent. (Designated as Exhibit No. 10.6 to the Current Report on Form 8-K dated December 17, 2008, File No. 1-12869.)
12(a)	Constellation Energy Group, Inc. and Subsidiaries Computation of Ratio of Earnings to Fixed Charges.
12(b)	Baltimore Gas and Electric Company and Subsidiaries Computation of Ratio of Earnings to Fixed Charges and Computation of Ratio of Earnings to Combined Fixed Charges and Preferred and Preference Dividend Requirements.

21	Subsidiaries of the Registrant.

23	Consent of PricewaterhouseCoopers LLP, Independent Registered Public Accounting Firm.
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.
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.
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.
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.
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.
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.
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.
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.

+ Management contract or compensatory plan or arrangement.

* Incorporated by Reference.

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CONSTELLATION ENERGY GROUP, INC. AND SUBSIDIARIES
AND
BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARIES

SCHEDULE II VALUATION AND QUALIFYING ACCOUNTS

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at beginning of period	Charged to costs and expenses	Charged to Other Accounts Describe	(Deductions) Describe	Balance at end of period
			(In millions)		
Reserves deducted in the Balance Sheet from the assets to which they apply:					
Constellation Energy					
Accumulated Provision for Uncollectibles					
2008	$ 44.9	$ 127.1	$ 102.3 (A)	$ (33.7)(B)	$ 240.6
2007	48.9	31.3		(35.3)(B)	44.9
2006	47.4	29.7		(28.2)(B)	48.9
Valuation Allowance					
Net unrealized (gain) loss on available for sale securities					
2008	(17.3)	7.0	0.3 (C)	12.1 (D)	2.1
2007	(18.5)		1.2 (C)		(17.3)
2006	0.6		(19.1)(C)		(18.5)
Net unrealized (gain) loss on nuclear decommissioning trust funds					
2008	(256.7)		207.1 (C)		(49.6)
2007	(206.1)		(50.6)(C)		(256.7)
2006	(110.3)		(95.8)(C)		(206.1)
BGE					
Accumulated Provision for Uncollectibles					
2008	21.1	34.5		(21.4)(B)	34.2
2007	16.1	21.0		(16.0)(B)	21.1
2006	13.0	18.1		(15.0)(B)	16.1

(A) Represents amounts recorded as a reduction to nonregulated revenues resulting from liquidated damages claims upon termination of derivatives which were determined to be uncollectible.

(B) Represents principally net amounts charged off as uncollectible.

(C) Represents amounts recorded in or reclassified from accumulated other comprehensive income.

(D) Represents sale of a marketable security.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, Constellation Energy Group, Inc., the Registrant, has duly caused this Report to be signed on its behalf by the undersigned, thereunto duly authorized.

CONSTELLATION ENERGY GROUP, INC.
(REGISTRANT)

Date: February 27, 2009 By /s/ MAYO A. SHATTUCK III

Mayo A. Shattuck III
Chairman of the Board, President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this Report has been signed below by the following persons on behalf of Constellation Energy Group, Inc., the Registrant, and in the capacities and on the dates indicated.

Signature	Title	Date
Principal executive officer and director:		
By /s/ M. A. Shattuck III **M. A. Shattuck III**	Chairman of the Board, President, Chief Executive Officer, and Director	February 27, 2009
Principal financial officer:		
By /s/ J. W. Thayer **J. W. Thayer**	Senior Vice President and Chief Financial Officer	February 27, 2009
Principal accounting officer:		
By /s/ R. K. Feuerman **R. K. Feuerman**	Vice President, Chief Accounting Officer, and Treasurer	February 27, 2009
Directors:		
/s/ Y. C. de Balmann **Y. C. de Balmann**	Director	February 27, 2009
/s/ D. L. Becker **D. L. Becker**	Director	February 27, 2009
/s/ A. C Berzin	Director	February 27, 2009

	A. C. Berzin		
/s/	J. T. Brady	Director	February 27, 2009
	J. T. Brady		
/s/	J. R. Curtiss	Director	February 27, 2009
	J. R. Curtiss		

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Signature	Title	Date
/s/ F. A. Hrabowski, III **F. A. Hrabowski, III**	Director	February 27, 2009
/s/ N. Lampton **N. Lampton**	Director	February 27, 2009
/s/ R. J. Lawless **R. J. Lawless**	Director	February 27, 2009
/s/ L. M. Martin **L. M. Martin**	Director	February 27, 2009
/s/ J. L. Skolds **J. L. Skolds**	Director	February 27, 2009
/s/ M. D. Sullivan **M. D. Sullivan**	Director	February 27, 2009

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Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, Baltimore Gas and Electric Company, the Registrant, has duly caused this Report to be signed on its behalf by the undersigned, thereunto duly authorized.

BALTIMORE GAS AND ELECTRIC COMPANY
(REGISTRANT)

February 27, 2009 By /s/ KENNETH W. DEFONTES, JR.

Kenneth W. DeFontes, Jr.
President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this Report has been signed below by the following persons on behalf of Baltimore Gas and Electric Company, the Registrant, and in the capacities and on the dates indicated.

Signature	Title	Date
Principal executive officer and director:		
By /s/ K. W. DeFontes, Jr.	President, Chief Executive Officer, and Director	February 27, 2009
K. W. DeFontes, Jr.		
Principal financial and accounting officer:		
By /s/ K. W. Hadlock	Senior Vice President and Chief Financial Officer	February 27, 2009
K. W. Hadlock		
Directors:		
/s/ T. F. Brady	Chairman of the Board of Directors	February 27, 2009
T. F. Brady		
/s/ M. A. Shattuck III	Director	February 27, 2009
M. A. Shattuck III		
/s/ J. Haskins Jr.	Director	February 27, 2009
J. Haskins Jr.		
/s/ C. Hayden	Director	February 27, 2009
C. Hayden		
/s/ M. D. Sullivan	Director	February 27, 2009

M. D. Sullivan

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EXHIBIT INDEX

Exhibit Number	
*2	Agreement and Plan of Share Exchange between Baltimore Gas and Electric Company and Constellation Energy Group, Inc. dated as of February 19, 1999. (Designated as Exhibit No. 2 to the Registration Statement on Form S-4 dated March 3, 1999, File No. 33-64799.)
*2(a)	Agreement and Plan of Reorganization and Corporate Separation (Nuclear). (Designated as Exhibit No. 2(a) to the Current Report on Form 8-K dated July 7, 2000, File Nos. 1-12869 and 1-1910.)
*2(b)	Agreement and Plan of Reorganization and Corporate Separation (Fossil). (Designated as Exhibit No. 2(b) to the Current Report on Form 8-K dated July 7, 2000, File Nos. 1-12869 and 1-1910.)
*2(c)	Termination Agreement, dated December 17, 2008, by and among Constellation Energy Group, Inc., Constellation Generation II, LLC, Constellation Power Source Generation, Inc., MidAmerican Energy Holdings Company, MEHC Merger Sub Inc., MEHC Investment, Inc. and Electricite de France International S.A. (Designated as Exhibit 2.1 to the Current Report on Form 8-K dated December 17, 2008, File No. 1-12869.)
*2(d)	Master Put Option and Membership Interest Purchase Agreement, dated as of December 17, 2008, by and among Constellation Energy Group, Inc., EDF Development, Inc. and Electricite de France International, S.A. (Designated as Exhibit No. 21 to the Current Report on Form 8-K dated December 17, 2008, File No. 1-12869.)
*3(a)	Articles Supplementary to the Charter of Constellation Energy Group, Inc. as of December 17, 2008. (Designated as Exhibit No. 3.1 to the Current Report on Form 8-K dated December 17, 2008, File No. 1-12869.)
*3(b)	Articles Supplementary to the Charter of Constellation Energy Group, Inc. as of September 19, 2008. (Designated as Exhibit No. 3.1 to the Current Report on Form 8-K dated September 19, 2008, File No. 1-12869.)
3(c)	Certificate of Correction to Articles Supplementary to the Charter of Constellation Energy Group, Inc. as of November 25, 2008.
*3(d)	Articles of Amendment and Restatement of the Charter of Constellation Energy Group, Inc. as of April 30, 1999. (Designated as Exhibit No. 99.2 to the Current Report on Form 8-K dated April 30, 1999, File No. 1-1910.)
*3(e)	Articles Supplementary to the Charter of Constellation Energy Group, Inc. as of April 10, 2007. (Designated as Exhibit 3(a) to the Current Report on Form 8-K dated April 10, 2007, File No. 1-12869.)
*3(f)	Articles Supplementary to the Charter of Constellation Energy Group, Inc. as of November 20, 2001. (Designated as Exhibit No. 3(e) to the Annual Report on Form 10-K for the year ended December 31, 2001, File Nos. 1-12869 and 1-1910.)
*3(g)	Certificate of Correction to the Charter of Constellation Energy Group, Inc. as of September 13, 1999. (Designated as Exhibit No. 3(c) to the Annual Report on Form 10-K for the year ended December 31, 1999, File Nos. 1-12869 and 1-1910.)
*3(h)	Articles Supplementary to the Charter of Constellation Energy Group, Inc., as of July 19, 1999. (Designated as Exhibit No. 3(a) to the Quarterly Report on Form 10-Q for the quarter ended June 30, 1999, File Nos. 1-12869 and 1-1910.)
*3(i)	Articles of Amendment and Restatement of Constellation Energy Group, Inc. as of April 30, 1999. (Designated as Appendix B to Post-Effective Amendment No. 1 to the Registration Statement on Form S-4 filed March 3, 1999, File No. 33-64799.)
*3(j)	Bylaws of Constellation Energy Group, Inc., as amended to July 18, 2008. (Designated as Exhibit No. 3 to the Current Report on Form 8-K dated July 18, 2008, File No. 1-12869.)
*3(k)	Charter of BGE, restated as of August 16, 1996. (Designated as Exhibit No. 3 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 1996, File No. 1-1910.)
*3(l)	Bylaws of BGE, as amended to October 16, 1998. (Designated as Exhibit No. 3 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 1998, File No. 1-1910.)

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*4(a)	Indenture between Constellation Energy Group, Inc. and the Bank of New York, Trustee dated as of March 24, 1999. (Designated as Exhibit No. 4(a) to the Registration Statement on Form S-3 dated March 29, 1999, File No. 333-75217.)
*4(b)	First Supplemental Indenture between Constellation Energy Group, Inc. and the Bank of New York, Trustee dated as of January 24, 2003. (Designated as Exhibit No. 4(b) to the Registration Statement on Form S-3 dated January 24, 2003, File No. 333-102723.)
*4(c)	Indenture dated June 19, 2008 between Constellation Energy Group, Inc. and Deutsche Bank Trust Company Americas, as trustee. (Designated as Exhibit No. 4(a) to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2008, File Nos. 1-12869 and 1-1910.)
*4(d)	Indenture dated July 1, 1985, between BGE and The Bank of New York (Successor to Mercantile-Safe Deposit and Trust Company), Trustee. (Designated as Exhibit 4(a) to the Registration Statement on Form S-3, File No. 2-98443); as supplemented by Supplemental Indentures dated as of October 1, 1987 (Designated as Exhibit 4(a) to the Current Report on Form 8-K, dated November 13, 1987, File No. 1-1910) and as of January 26, 1993 (Designated as Exhibit 4(b) to the Current Report on Form 8-K, dated January 29, 1993, File No. 1-1910.)
*4(e)	Form of Subordinated Indenture between the Company and The Bank of New York, as Trustee in connection with the issuance of the Junior Subordinated Debentures. (Designated as Exhibit 4(d) to the Registration Statement on Form S-3 dated August 5, 2003, File No. 333-107681.)
*4(f)	Form of Supplemental Indenture between the Company and The Bank of New York, as Trustee in connection with the issuances of the Junior Subordinated Debentures. (Designated as Exhibit 4(e) to the Registration Statement on Form S-3 dated August 5, 2003, File No. 333-107681.)
*4(g)	Form of Preferred Securities Guarantee (Designated as Exhibit 4(f) to the Registration Statement on Form S-3 dated August 5, 2003, File No. 333-107681.)
*4(h)	Form of Junior Subordinated Debenture (Designated as Exhibit 4(h) to the Registration Statement on Form S-3 dated August 5, 2003, File No. 333-107681.)
*4(i)	Form of Amended and Restated Declaration of Trust (including Form of Preferred Security) (Designated as Exhibit 4(c) to the Registration Statement on Form S-3 dated August 5, 2003, File No. 333-107681.)
*4(j)	Indenture dated as of July 24, 2006 between Constellation Energy Group, Inc. and Deutsche Bank Trust Company Americas, as trustee. (Designated as Exhibit 4(a) to the Registration Statement on Form S-3 filed July 24, 2006, File No. 333-135991.)
*4(k)	First Supplemental Indenture between Constellation Energy Group, Inc. and Deutsche Bank Trust Company Americas, as trustee, dated as of June 27, 2008. (Designated as Exhibit No. 4(a) to the Current Report on Form 8-K dated June 30, 2008, File No. 1-12869.)
*4(l)	Indenture dated as of July 24, 2006 between Baltimore Gas and Electric Company and Deutsche Bank Trust Company Americas, as trustee. (Designated as Exhibit 4(b) to the Registration Statement on Form S-3 filed July 24, 2006, File No. 333-135991.)
*4(m)	First Supplemental Indenture between Baltimore Gas and Electric Company and Deutsche Bank Trust Company Americas, as trustee, dated as of October 13, 2006. (Designated as Exhibit 4(a) to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2006, File Nos. 1-12869 and 1-1910.)
*4(n)	Indenture dated as of June 29, 2007, by and between RSB BondCo LLC and Deutsche Bank Trust Company Americas, as Trustee and Securities Intermediary. (Designated as Exhibit 4.1 to the Current Report on Form 8-K dated July 5, 2007, File No. 1-1910.)
*4(o)	Series Supplement to Indenture dated as of June 29, 2007 by and between RSB BondCo LLC and Deutsche Bank Trust Company Americas, as Trustee and Securities Intermediary (Designated as Exhibit 4.2 to the Current Report on Form 8-K dated July 5, 2007, File No. 1-1910.)
*4(p)	Replacement Capital Covenant dated June 27, 2008. (Designated as Exhibit No. 4(b) to the Current Report on Form 8-K dated June 30, 2008, File

	No. 1-12869.)
+*10(a)	Executive Annual Incentive Plan of Constellation Energy Group, Inc., as amended and restated. (Designated as Exhibit No. 10(d) to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2008, File Nos. 1-12869 and 1-1910.)
+10(b)	Constellation Energy Group, Inc. Nonqualified Deferred Compensation Plan, as amended and restated.

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10(c)	Constellation Energy Group, Inc. Deferred Compensation Plan for Non-Employee Directors, as amended and restated.
+10(d)	Constellation Energy Group, Inc. Benefits Restoration Plan, as amended and restated.
+10(e)	Constellation Energy Group, Inc. Supplemental Pension Plan, as amended and restated.
+10(f)	Constellation Energy Group, Inc. Senior Executive Supplemental Plan, as amended and restated.
+*10(g)	Constellation Energy Group, Inc. Supplemental Benefits Plan, as amended and restated. (Designated as Exhibit No. 10(a) to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2008, File Nos. 1-12869 and 1-1910.)
+10(h)	Second amended and restated change in control severance agreement between Constellation Energy Group, Inc. and Mayo A. Shattuck III.
+10(i)	Second amended and restated change in control severance agreement between Constellation Energy Group, Inc. and John R. Collins
+*10(j)	Constellation Energy Group, Inc. 1995 Long-Term Incentive Plan, as amended and restated. (Designated as Exhibit No. 10(b) to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2004, File Nos. 1-12869 and 1-1910.)
+*10(k)	Constellation Energy Group, Inc. Executive Long-Term Incentive Plan, as amended and restated. (Designated as Exhibit 10(b) to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2006, File Nos. 1-12869 and 1-1910.)
+*10(l)	Constellation Energy Group, Inc. 2002 Executive Annual Incentive Plan, as amended and restated. (Designated as Exhibit 10(o) to the Annual Report on Form 10-K for the year ended December 31, 2006, File Nos. 1-12869 and 1-1910.)
+*10(m)	Constellation Energy Group, Inc. 2002 Senior Management Long-Term Incentive Plan, as amended and restated. (Designated as Exhibit 10(c) to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2006, File Nos. 1-12869 and 1-1910.)
+*10(n)	Constellation Energy Group, Inc. Management Long-Term Incentive Plan, as amended and restated. (Designated as Exhibit 10(d) to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2006, File Nos. 1-12869 and 1-1910.)
+*10(o)	Constellation Energy Group, Inc. 2007 Long-Term Incentive Plan, as amended and restated. (Designated as Exhibit 10(a) to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2008, File Nos. 1-12869 and 1-1910.)
*10(p)	Grantor Trust Agreement Dated as of February 27, 2004 between Constellation Energy Group, Inc. and Citibank, N.A. (Designated as Exhibit No. 10(d) to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2004, File Nos. 1-12869 and 1-1910.)
*10(q)	Grantor Trust Agreement dated as of February 27, 2004 between Constellation Energy Group, Inc. and T. Rowe Price Trust Company. (Designated as Exhibit No. 10(b) to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2004, File Nos. 1-12869 and 1-1910.)
*10(r)	Rate Stabilization Property Servicing Agreement dated as of June 29, 2007 by and between RSB BondCo LLC and Baltimore Gas and Electric Company, as servicer (Designated as Exhibit 10.2 to the Current Report on Form 8-K dated July 5, 2007, File No. 1-1910.)
*10(s)	Administration Agreement dated as of June 29, 2007 by and between RSB BondCo LLC and Baltimore Gas and Electric Company, as administrator (Designated as Exhibit 10.3 to the Current Report on Form 8-K dated July 5, 2007, File No. 1-1910.)
*10(t)	Investor Rights Agreement, dated as of September 19, 2008, by and between Constellation Energy Group, Inc. and MidAmerican Energy Holdings Company. (Designated as Exhibit No. 10.3 to the Current Report on Form 8-K dated September 19, 2008, File No. 1-12869.)
*10(u)	Letter Agreement, dated December 17, 2008, by and among Constellation Energy Group, Inc., MidAmerican Energy Holdings Company, MEHC Merger Sub Inc. and MEHC Investment, Inc. (Designated as Exhibit No. 10.1 to the Current Report on Form 8-K dated December 17, 2008, File No. 1-12869.)

*10(v)	Form of CENG Operating Agreement (Designated as Exhibit No. 10.1 to the Current Report on Form 8-K dated December 17, 2008, File No. 1-12869.)

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*10(w)	Stock Purchase Agreement, dated as of December 17, 2008, by and among Constellation Energy Group, Inc., EDF Development, Inc. and Electricite de France International, S.A. (Designated as Exhibit No. 10.2 to the Current Report on Form 8-K dated December 17, 2008, File No. 1-12869.)
*10(x)	Investor Rights Agreement, dated as of December 17, 2008, by and between Constellation Energy Group, Inc. and EDF Development, Inc. (Designated as Exhibit No. 10.3 to the Current Report on Form 8-K dated December 17, 2008, File No. 1-12869.)
*10(y)	Payment Guaranty, dated as of December 17, 2008, by and between Constellation Energy Group, Inc. and Electricite de France, S.A. (Designated as Exhibit No. 10.4 to the Current Report on Form 8-K dated December 17, 2008, File No. 1-12869.)
*10(z)	Amended and Restated Investor Agreement, dated December 17, 2008, by and between Constellation Energy Group, Inc. and Electricite de France International, SA (Designated as Exhibit 10.7 to the Current Report on Form 8-K dated December 17, 2008, File No. 1-12869.)
*10(aa)	Amended and Restated Credit Agreement, dated as of December 17, 2008, among Constellation Energy Group, Inc., the Lenders named therein and the Royal Bank of Scotland PLC, as Administrative Agent. (Designated as Exhibit No. 10.5 to the Current Report on Form 8-K dated December 17, 2008, File No. 1-12869.)
*10(bb)	Second Amended and Restated Credit Agreement, dated as of December 17, 2008, among Constellation Energy Group, Inc., the Lenders named therein, Wachovia Bank, National Association, as Administrative Agent, LC Bank, Swingline Lender and Collateral Agent. (Designated as Exhibit No. 10.6 to the Current Report on Form 8-K dated December 17, 2008, File No. 1-12869.)
12(a)	Constellation Energy Group, Inc. and Subsidiaries Computation of Ratio of Earnings to Fixed Charges.
12(b)	Baltimore Gas and Electric Company and Subsidiaries Computation of Ratio of Earnings to Fixed Charges and Computation of Ratio of Earnings to Combined Fixed Charges and Preferred and Preference Dividend Requirements.
21	Subsidiaries of the Registrant.
23	Consent of PricewaterhouseCoopers LLP, Independent Registered Public Accounting Firm.
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.
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.
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.
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.
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.
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.
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.
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.

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Management contracts or compensatory plan or arrangement.

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Incorporated by Reference.