BALTIMORE GAS & ELECTRIC CO
Form 10-K
February 29, 2012

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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, 2011**

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

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

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

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

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

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

MARYLAND
(States of incorporation of both registrants)

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

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

Indicate by check mark whether Constellation Energy Group, Inc. is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See 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, 2011 was approximately $7,621,809,578 based upon New York Stock Exchange composite transaction closing price.

CONSTELLATION ENERGY GROUP, INC. COMMON STOCK, WITHOUT PAR VALUE
201,878,759 SHARES OUTSTANDING ON JANUARY 31, 2012.

DOCUMENTS INCORPORATED BY REFERENCE

Part of Form 10-K	Document Incorporated by Reference
III	Certain sections of the Proxy Statement for the 2012 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, and emission allowances, and the impact of such changes on our liquidity requirements,
- the liquidity and competitiveness of wholesale and retail markets for energy commodities,
- the conditions of the capital markets, interest rates, foreign exchange rates, availability of credit facilities to support business requirements, liquidity, and general economic conditions, as well as Constellation Energy Group's (Constellation Energy) and Baltimore Gas and Electric's (BGE) ability to maintain their current credit ratings,
- the effectiveness of Constellation Energy's and BGE's risk management policies and procedures and the ability and willingness of our counterparties to satisfy their financial and performance commitments,
- losses on the sale or write-down of assets due to impairment events or changes in management intent with regard to either holding or selling certain assets,
- the ability to successfully identify, finance, and complete acquisitions and sales of businesses and assets, including generating facilities, and to successfully invest in new business initiatives and markets,
- the effect of weather and general economic and business conditions on energy supply, demand, prices, and customers' and counterparties' ability to perform their obligations or make payments,
- the ability to attract and retain customers in our NewEnergy business and to adequately forecast their energy usage,
- the timing and extent of customer choice and competition in the energy markets and the rules and regulations adopted in those markets,
- regulatory or legislative developments federally, in Maryland, or in other states that affect energy competition, the price of energy, transmission or distribution rates and revenues, demand for energy, or increases in costs, including costs related to safety or environmental compliance,
- the ability of our regulated and nonregulated businesses to comply with complex and/or changing market rules and regulations,
- the ability of BGE to recover all its costs associated with providing customers service,
- operational factors affecting our generating facilities, BGE's transmission and distribution facilities, or our other commercial operations, including weather-related damages, unscheduled outages or repairs, unanticipated changes in fuel costs or availability, unavailability of coal or gas transportation or electric transmission services, workforce issues, terrorism, acts of war, catastrophic events, and other events beyond our control,
- the impact of industry consolidation,
- the impact of increased energy conservation and use of renewable energy,

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

- changes in accounting principles or practices,

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

- the likelihood and timing of the completion of the pending merger with Exelon Corporation, the terms and conditions of any required regulatory approvals of the pending merger, and potential diversion of management's time and attention from our ongoing business during this time period.

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 generation business (Generation), a customer supply business (NewEnergy), 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 Generation business develops, owns, owns interests in, and operates electric generation facilities and a fuel processing facility located in various regions of the United States and Canada. This business also includes an operation that manages certain contractually controlled physical assets, including generating facilities and owns an interest in a joint venture that owns and operates nuclear generating facilities.

Our NewEnergy business is primarily a competitive provider of energy-related products and services for a variety of customers and focuses on selling electricity, natural gas, and other energy-related products to serve customers' requirements (load-serving), and providing other energy products and risk management services. This business also manages our upstream natural gas activities, designs, constructs, and operates renewable energy, heating, cooling, and cogeneration facilities and provides home improvements, sales of electric and gas appliances, and servicing of heating, air conditioning, plumbing, electrical, and indoor air quality systems.

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.

On April 28, 2011, Constellation Energy entered into an Agreement and Plan of Merger with Exelon Corporation (Exelon). At closing, each issued and outstanding share of common stock of Constellation Energy will be cancelled and converted into the right to receive 0.93 shares of common stock of Exelon, and Constellation Energy will become a wholly owned subsidiary of Exelon.

The merger agreement contains certain termination rights for both Constellation Energy and Exelon. Under narrow specified circumstances in which the merger agreement is terminated and another acquisition proposal is accepted, Constellation Energy may be required to pay Exelon a termination fee of $200 million and Exelon may be required to pay Constellation Energy a termination fee of $800 million.

In connection with the proposed merger, Exelon and Constellation Energy offered numerous commitments, each of which is contingent upon completion of the merger, in support of their request for approval of the merger with the Maryland Public Service Commission (Maryland PSC). In addition, in December 2011, Exelon, Exelon Energy Delivery Company, LLC, Constellation Energy, and BGE entered into a settlement agreement with the State of Maryland, the Maryland Energy Administration, the City of Baltimore and the Baltimore Building and Construction Trades Council, in which they agreed to several additional commitments contingent upon completion of the merger.

In January 2012, Exelon, Exelon Energy Delivery Company, LLC, Constellation Energy, and BGE entered into a settlement agreement with EDF Group and affiliates (EDF) in which, subject to the consummation of the merger with Exelon, the parties agreed to amendments to the operating agreement of Constellation Energy Nuclear Group, LLC, a nuclear joint venture between Constellation Energy and EDF, an existing Administrative Services Agreement (ASA) and an existing Power Services Agency Agreement (PSA). We discuss the ASA and PSA in more detail in *Note 16 to the Consolidated Financial Statements*.

The merger agreement has been approved by the boards of directors and stockholders of both Constellation Energy and Exelon and by several other state and federal regulatory bodies. The parties are working to complete the merger in the first quarter of 2012 absent any Federal Energy Regulatory Commission approval delays.

Operating Segments

The percentages of revenues, net income (loss) attributable to common stock, 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

	Generation	NewEnergy	Regulated Electric	Regulated Gas	Holding Company and Other
2011	8%	70%	17%	5%	%
2010	8	68	19	5	
2009	4	73	18	5	

Net (Loss) Income Attributable to Common Stock

	Generation	NewEnergy	Regulated Electric	Regulated Gas	Holding Company and Other
2011	(130)%	(5)%	25%	11%	(1)%
2010	(128)	14	10	4	
2009	107	(9)	1	1	

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Total Assets						
	Generation	NewEnergy	Regulated Electric	Regulated Gas	Holding Company and Other	Eliminations
2011	45%	21%	28%	8%	4%	(6)%
2010	49	19	26	7	4	(5)
2009	53	18	21	6	19	(17)

Generation Business

We develop, own, operate, and maintain fossil and renewable generating facilities, hold a 50.01% interest in a nuclear joint venture that owns nuclear generating facilities, hold interests in qualifying facilities, and power projects in the United States and Canada totaling 11,751 MW as of December 31, 2011, and manage approximately 1,100 MW associated with certain of our long-dated tolling agreements. These agreements provide us with the contractual rights to purchase power from third party generation plants over an extended period of time. The output of our owned and contractually controlled plants is managed by our NewEnergy business and is hedged through a combination of power sales to wholesale and retail market participants. We also provide operation and maintenance services, including testing and start-up, to owners of electric generating facilities. Our NewEnergy business meets the load-serving requirements under 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.*

Investment in Nuclear Generating Facilities

On November 6, 2009, we completed the sale of a 49.99% membership interest in Constellation Energy Nuclear Group LLC and affiliates (CENG), our subsidiary that owns our nuclear generating facilities described below. The total output of these nuclear facilities over the past three years is presented in the following table:

	Calvert Cliffs		Nine Mile Point		Ginna	
	MWH	Capacity Factor	MWH (1)	Capacity Factor	MWH	Capacity Factor
			(MWH in millions)			
2011	14.4	96%	12.4	91%	4.3	85%
2010	14.0	94	12.6	93	4.9	97
2009	14.5	96	13.1	97	4.6	91

(1) *Represents our and CENG's (after November 6, 2009) proportionate ownership interest*

We have a unit contingent power purchase agreement (PPA) with CENG under which we purchase 85 to 90% of the output of CENG's nuclear plants that is not sold to third parties under pre-existing PPAs through 2014. Beginning on January 1, 2015, and continuing to the end of the lives of the respective nuclear plants, we will purchase 50.01% and EDF will purchase 49.99% of the output of CENG's nuclear plants. We discuss this PPA in more detail in *Note 16 to Consolidated Financial Statements*.

Calvert Cliffs

CENG owns 100% of Calvert Cliffs Unit 1 and Unit 2. 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

CENG owns 100% of Nine Mile Point Unit 1 and 82% of Unit 2. 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.

Nine Mile Point Unit 2 sold 90% of the plant's output to the former owners of the plant at an average price of approximately $35 per MWH under a PPA that terminated in November 2011. The PPA was unit contingent. (Under a unit contingent contract, 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 the output of Nine Mile Point Unit 2 was managed by CENG and sold primarily to us and EDF.

After expiration of the Nine Mile Point Unit 2 PPA, a revenue sharing agreement with the former owners of the plant began and will continue through November 2021. Under this agreement, which applies only to CENG's 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 Unit 2.

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

Ginna

CENG owns 100% of the Ginna nuclear facility. Ginna entered service in 1970 and is licensed to operate until 2029. Ginna sells approximately 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 PPA. The

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remaining 10% of the output of Ginna is managed by CENG and sold primarily to us and EDF.

Qualifying Facilities and Power Projects

We hold up to a 50% voting interest in 15 operating energy projects, totaling approximately 758 MW, that consist of electric generation (primarily relying on alternative fuel sources), fuel processing, or fuel handling facilities. Thirteen 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.

Contracted Generation

We manage approximately 1,100 MWs under three agreements with third party generators in which we have long-dated contractual rights to purchase power from these third party generating plants. The economics of these transactions are similar to our owned generation.

NewEnergy Business

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

To meet our customers' requirements, our NewEnergy business obtains energy from various sources, including:

- our generation assets,
- our contractually controlled 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 up to five years, and
- regional power pools.

During 2011, our NewEnergy business:

- supplied approximately 131 million megawatt hours (MWH) of aggregate electricity to distribution utilities, municipalities, and residential, commercial, industrial, and governmental customers,
- provided approximately 330 million mmBTUs (million British Thermal Units) of natural gas to residential, commercial, industrial, and governmental customers,
- delivered approximately 5.5 million tons of coal primarily to our own fleet, and
- delivered approximately 213 million mmBTUs of natural gas to our fleet of owned and contracted generation assets.

Our NewEnergy business also manages certain contractually controlled physical assets, including generation facilities (excluding long-dated tolling agreements managed by our Generation business), and natural gas properties, provides risk management services, and trades energy and energy-related commodities. This business also provides the wholesale risk management function for our Generation business, as well as structured products and energy investment activities and includes our actual hedged positions with third parties.

Our NewEnergy business also manages our upstream natural gas activities, designs, constructs, and operates renewable energy, heating, cooling, and cogeneration facilities and provides home improvements, sales of electric and gas appliances, and servicing of heating, air conditioning, plumbing, electrical, and indoor air quality systems.

Wholesale Customer Supply

In 2011, our wholesale NewEnergy customer supply operation served approximately 62 million MWHs of wholesale full requirements electricity and related load-serving products.

Our wholesale NewEnergy 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 have in-house supply functions to meet their own load requirements.

Retail Customer Supply

During 2011, our retail NewEnergy customer supply operation served approximately 69 million MWHs of electricity load and approximately 330 mmBTUs of natural gas. Our volume served in 2011 increased compared to the prior year as a result of the acquisition of Star Electricity, Inc. (StarTex) (May 2011) and MXenergy Holdings Inc. (MXenergy) (July 2011). We discuss these acquisitions in more detail in *Note 15 to Consolidated Financial Statements.*

Our retail NewEnergy customer supply operation structures transactions to supply full energy and capacity requirements and provide natural gas, transportation, and other energy products and services to commercial, industrial, governmental, and residential customers. Contracts with these customers generally extend from one to ten years, but some can be longer.

The retail NewEnergy customer supply operation combines a unified sales force with a customer-centric model that leverages technology to broaden the range of products and services we offer, which we believe promotes stronger customer relationships. This model focuses on efficiency and cost reduction, which we believe will provide a platform that is scalable and able to capitalize on opportunities for future growth.

Structured Products

Our NewEnergy business 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 NewEnergy business assists customers with customized risk management products in the power, gas, coal, and freight markets (e.g., generation tolls and gas transport and storage).

Energy Investments

Our NewEnergy business has investments in energy assets that primarily include natural gas activities. Our NewEnergy business includes upstream (exploration and production) and downstream (transportation and storage) natural gas operations. Our upstream natural gas activities include the development, exploration, and exploitation of natural gas properties. During 2011, we sold substantially all of our interests in Constellation Energy Partners LLC (CEP), a company formed by us and principally engaged in the acquisition, development, and exploitation of natural gas properties, to PostRock Energy Corporation. We do not have any involvement in the day-to-day operations of CEP. We discuss the sale of our interests in CEP in more detail in *Note 2 to Consolidated Financial Statements*.

Portfolio Management and Trading

Our NewEnergy business transacts in energy and energy-related commodities in order to manage our portfolio of energy purchases and sales to customers through structured transactions. We use economic value at risk, which measures the market risk in our total portfolio, encompassing all aspects of our NewEnergy business, along with daily value at risk limits, stop loss limits, position limits, generation hedge ratios, and liquidity guidelines to restrict the level of risk in our portfolio.

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 NewEnergy 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 economic 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
- 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).

Our energy trading activities are being used primarily for hedging our Generation and NewEnergy businesses, price discovery and verification, and for deploying limited risk capital.

Fuel Sources

Our power plants use diverse fuel sources. Our plants' fuel mix based on capacity owned at December 31, 2011 and actual output by fuel type during 2011 was as follows:

Fuel	Capacity Owned	Generation
Nuclear (1)	16%	30%
Coal	23	24
Natural Gas	42	41
Oil	6	
Renewable and Alternative (2)	5	5
Dual (3)	8	

(1)
Reflects our 50.01% ownership interest in CENG.

(2)
Includes solar, hydro, waste coal, and biomass.

(3)
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

CENG, our nuclear joint venture with EDF, owns the Calvert Cliffs, Nine Mile Point, and Ginna nuclear generating facilities.

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The supply of fuel for these nuclear generating facilities includes the:

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

CENG has commitments that provide for quantities of uranium, conversion, enrichment, and fabrication of fuel assemblies to substantially meet expected requirements for the next several years at these nuclear generating facilities.

The uranium markets are competitive, and while prices can be volatile, CENG does not anticipate problems in meeting its future supply requirements.

Storage of Spent Nuclear Fuel

The Nuclear Waste Policy Act of 1982, as amended, ("NWPA") requires 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. Although the NWPA and CENG's contracts with the DOE required the DOE to begin taking possession of spent nuclear fuel no later than January 31, 1998, the DOE has thus far failed to meet its obligation. The DOE's delay in taking possession of spent fuel has required CENG to undertake additional actions and incur costs to provide on-site dry fuel storage at all three of its nuclear sites. CENG has installed additional capacity at its independent spent fuel storage installation ("ISFSI") at Calvert Cliffs and Ginna, and is constructing an ISFSI to be placed in service at Nine Mile Point in 2012.

Prior to 2010, the DOE had stated that it may not meet its obligation until 2020 at the earliest. During 2010, the DOE requested the withdrawal of its license application to use Yucca Mountain as a national repository for spent nuclear fuel. At this time, CENG is not able to determine whether the DOE will be able to commence meeting its obligation by 2020.

Each of CENG's plant subsidiaries have filed complaints against the federal government in the U.S. 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. Any funds received from the DOE that represent the settlement of claims incurred prior to November 6, 2009, the date we sold a 49.99% membership interest in CENG to EDF, will belong to Constellation Energy, and any funds representing the settlement of claims incurred after November 6, 2009 will belong to CENG. During 2011, CENG executed settlement agreements with the DOE that detail a framework and procedure for recovery of damages incurred or to be incurred through the end of 2013 at the Calvert Cliffs and Ginna nuclear power plants. Constellation Energy, through its share of the settlement proceeds, received the following amounts in 2011for costs incurred through November 6, 2009 to store spent nuclear fuel:

- $39.4 million related to costs at the Calvert Cliffs nuclear power plant, and
- $54.4 million related to costs at the Ginna nuclear power plant.

The lawsuit relating to the storage of spent nuclear fuel at the Nine Mile Point power plant remains outstanding.

Cost for Decommissioning Nuclear Facilities

When Constellation Energy sold a 49.99% membership interest in CENG on November 6, 2009, we deconsolidated CENG for financial reporting purposes and, as a result, the decommissioning trust funds were removed from our Consolidated Balance Sheets. CENG is obligated to decommission its nuclear power plants after these plants permanently cease operation.

Decommissioning activities are currently projected to be staged through the 2080 decade. 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, additional funding would have to be provided by CENG. CENG has the ability to request funding assistance from both Constellation Energy and EDF, as the owners of CENG.

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 were 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.

Coal

We purchase the majority of our coal for electric generation under supply contracts with mine operators, and we acquire the remainder in the spot or forward coal markets. 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. 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)	2,450,000
C. P. Crane Units 1 and 2 (combined) (1)	650,000
H. A. Wagner Units 2 and 3 (combined)	600,000

(1)

Assuming 100% sub-bituminous coal

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 and terminal 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 using sub-bituminous coal from the Western United States at C.P. Crane and have the ability to switch to using imported coal at Brandon Shores and H.A. Wagner 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. To comply with the HAA requirements, we are planning to burn domestic and/or import compliance coals (1.2 lb/mmbtu SO_2 or less) at H.A. Wagner. The C.P. Crane station was converted to burn up to 100% sub-bituminous coal in June 2010. In March 2010, we completed installation of flue gas desulfurization (FGD) equipment on both Brandon Shores units. With the FGD installation, Brandon Shores now is able to burn higher sulfur coals (limit 6 lbs/mmbtu or approximately 3.5% sulfur) while simultaneously reducing station emissions. The blend of coals actually procured for Brandon Shores will be optimized to achieve the lowest delivered cost while complying with HAA limitations.

We own an undivided interest in the Keystone and Conemaugh electric generating plants in Western Pennsylvania. Our ownership interests in these plants are 20.99% in Keystone and 10.56% in Conemaugh. All of the Conemaugh and Keystone plants' annual coal requirements are purchased from regional suppliers on the open market. FGD equipment was installed on both of the Keystone units in 2009 and has been installed on both Conemaugh units since the mid-1990s. The FGD SO_2 restrictions on coal are 6 lbs/mmbtu (or approximately 3.7% sulfur) for the Keystone plant and approximately 4.9 lbs/mmbtu (or 3% sulfur) for the Conemaugh plant. The blend of coal procured is optimized to ensure compliance with station emission limits at the lowest delivered cost.

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 expected 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.

In connection with the merger with Exelon, we have committed to sell three coal plants: Brandon Shores, C.P. Crane, and H.A. Wagner, within six months of the completion of the merger.

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

Our requirements for residual fuel oil (No. 6) amount 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

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

We face competition in the retail and wholesale market for energy, capacity, and ancillary services. In our NewEnergy business, we compete with international, national, and regional full-service energy providers, merchants, and producers to obtain and supply competitively priced products 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, and innovation of our products.

With respect to our Generation business, 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.

Many states are considering different types of regulatory initiatives concerning competition in the power and gas industry, which makes a general assessment of the state of competitive markets difficult. Many states continue to support or expand retail competition and industry restructuring. Other states that were considering restructuring have slowed their plans or postponed consideration of competitive markets. In addition, states that have restructured their energy markets routinely consider new market rules that could result in more limited opportunities for competitive energy suppliers like Constellation Energy. While some uncertainty remains in this area, we believe there is adequate growth potential in the current competitive market along with some probability of more markets opening to competition.

The market for commercial, industrial, and governmental energy supply continues to grow and we continue to experience increased competition from energy and non-energy market participants on a regional and national basis in our retail customer supply activities. Strong retail competition and the impact of power prices compared to the rates charged by local utilities affects the contract margin we receive from our customers. With sustained low forward natural gas and power prices and low market volatility, overall margins have tightened as competitors have aggressively pursued market share. We continue to expand our product offerings and customer service experience to support renewals and grow our customer base. Our experience and expertise in assessing and managing risk, and our strong focus on customer service, should help us to remain competitive during volatile or otherwise adverse market conditions.

Generation and NewEnergy Operating Statistics

	2011	**2010**	**2009**
Gross Margin *(In millions)*			
Generation (1)	**$ 951**	$ 800	$ 2,082
NewEnergy	**1,049**	1,244	1,079
Total Gross Margin	**$ 2,000**	$ 2,044	$ 3,161
Generation *(In millions)* MWH (1)(2)	**51.3**	35.1	46.0

Operating statistics do not reflect the elimination of intercompany transactions.

(1) *2009 reflects our 100% ownership in our nuclear business through November 6, 2009 and our 50.01% ownership in our nuclear business from November 6, 2009 through December 31, 2009 following the sale of a 49.99% membership interest in CENG. These amounts also exclude contracted generation.*

(2) *These amounts exclude contracted generation.*

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.

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Electric Business

Electric Competition

Maryland has implemented electric customer choice and competition among electric suppliers. As a result, all customers can choose their electric energy supplier, which includes subsidiaries of Constellation Energy. 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 by the Maryland PSC 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 from June 1, 2008 through May 31, 2010 without having to rebate it to all residential electric customers. Starting June 1, 2010, BGE provides all residential electric customers a credit for the residential return component of the administrative charge through December 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 terms of three months or two years.

Commercial and Industrial Customers

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

Residential Customers

Residential customers went to full market rates in January 2008. Pursuant to the order issued by the Maryland PSC in October 2009 approving our transaction with EDF, BGE, in 2010, provided rate credits totaling $112.4 million to it s residential customers. Constellation Energy made a $66 million equity contribution to BGE in December 2009 to fund the after-tax amount of the rate credit as required by the Maryland PSC order.

In 2010, the Maryland PSC issued a rate order authorizing BGE to increase electric and gas distribution rates for service rendered on or after December 4, 2010 by no more than $31.0 million for electric distribution rates and by no more than $9.8 million for gas distribution rates. We discuss this rate order in more detail in *Item 7. Management's Discussion and Analysis Regulation Maryland Base Rates* 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 controls for residential and commercial customers through both programmable thermostats and load control devices, and
- residential water heater controls.

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.

In August 2010, the Maryland PSC approved a comprehensive smart grid initiative for BGE which includes the planned installation of 2 million residential and commercial electric and gas smart meters at an expected total cost of approximately $480 million. Under a grant from the DOE, BGE is a recipient of $200 million in federal funding for our smart grid and other related initiatives. This grant allows BGE to be reimbursed for smart grid and other related expenditures up to $200 million, substantially reducing the total cost of these initiatives. As of December 31, 2011, BGE has received approximately $95.3 million of the $200 million grant from the DOE. If BGE fails to meet its obligation to incur certain costs under the DOE grant or BGE's completion of the smart grid initiative is delayed beyond approved DOE grant deadlines for incurring costs under the grant program, BGE's grant could be impacted, which could substantially increase the total cost for these initiatives.

The Maryland PSC initially approved a full portfolio of conservation programs for implementation in 2009 for a three year period through 2011 as well as a customer surcharge to recover the associated costs. This customer surcharge is updated annually. In December 2011, the Maryland PSC approved BGE's conservation programs for implementation in 2012 through 2014 as well as the annual update to the customer surcharge to recover the associated costs.

Transmission and Distribution Facilities

BGE maintains approximately 240 substations and approximately 1,300 circuit miles of transmission lines throughout central Maryland. BGE also maintains approximately 24,800 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.

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BGE Electric Operating Statistics

	2011	2010	2009
Revenues *(In millions)*			
Residential			
Excluding Delivery Service Only	**$ 1,347.4**	$ 1,808.6	$ 1,864.0
Delivery Service Only	**108.1**	48.1	14.3
Commercial			
Excluding Delivery Service Only	**387.3**	467.4	531.2
Delivery Service Only	**275.1**	249.5	245.0
Industrial			
Excluding Delivery Service Only	**22.5**	28.7	30.4
Delivery Service Only	**29.0**	25.6	29.1
System Sales and Deliveries	**2,169.4**	2,627.9	2,714.0
Other (1)	**152.0**	124.4	106.7
Total	**$ 2,321.4**	$ 2,752.3	$ 2,820.7
Distribution Volumes *(In thousands)* MWH			
Residential			
Excluding Delivery Service Only	**9,821**	12,344	12,394
Delivery Service Only	**2,831**	1,490	457
Commercial			
Excluding Delivery Service Only	**3,259**	3,707	3,945
Delivery Service Only	**13,220**	12,537	11,753
Industrial			
Excluding Delivery Service Only	**215**	267	270
Delivery Service Only	**2,463**	2,519	2,757
Total	**31,809**	32,864	31,576
Customers *(In thousands)*			
Residential	**1,116.4**	1,114.7	1,111.9
Commercial	**118.9**	118.6	118.5
Industrial	**5.8**	5.5	5.3
Total	**1,241.1**	1,238.8	1,235.7

(1) *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 DTH per day.

BGE's current maximum storage entitlements are 297,091 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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BGE Gas Operating Statistics

	2011	2010	2009
Revenues *(In millions)*			
Residential			
Excluding Delivery Service Only	**$ 383.3**	$ 427.0	$ 460.7
Delivery Service Only	**31.6**	22.1	19.0
Commercial			
Excluding Delivery Service Only	**103.9**	109.0	129.1
Delivery Service Only	**40.9**	39.8	40.4
Industrial			
Excluding Delivery Service Only	**4.6**	5.2	6.4
Delivery Service Only	**15.7**	16.7	15.2
System Sales and Deliveries	**580.0**	619.8	670.8
Off-System Sales	**81.8**	79.8	81.1
Other	**9.9**	9.8	6.4
Total	**$ 671.7**	$ 709.4	$ 758.3
Distribution Volumes *(In thousands)* DTH			
Residential			
Excluding Delivery Service Only	**33,680**	37,791	37,889
Delivery Service Only	**5,983**	4,857	4,270
Commercial			
Excluding Delivery Service Only	**11,098**	11,606	12,066
Delivery Service Only	**26,446**	24,329	25,046
Industrial			
Excluding Delivery Service Only	**540**	595	635
Delivery Service Only	**17,053**	19,750	20,826
System Sales and Deliveries	**94,800**	98,928	100,732
Off-System Sales	**16,436**	14,711	17,542
Total	**111,236**	113,639	118,274
Customers *(In thousands)*			
Residential	**608.9**	608.6	606.8
Commercial	**43.1**	42.9	42.9
Industrial	**1.1**	1.1	1.1
Total	**653.1**	652.6	650.8

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.

Consolidated Capital Requirements

Our total capital requirements, excluding acquisitions, for 2011 were $1.2 billion. Of this amount, $0.5 billion was used in our Generation and NewEnergy businesses and $0.7 billion was used in our regulated business. We estimate our total capital requirements will be $1.2 billion in 2012.

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.

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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 $1.2 billion during the five-year period 2007-2011 to comply with existing environmental standards and regulations, including the Maryland Healthy Air Act (HAA). Our estimated environmental capital requirements for the next three years are approximately $20 million in 2012, $30 million in 2013, and $40 million in 2014.

Air Quality

Federal

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

National Ambient Air Quality Standards (NAAQS)

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

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 nitrogen oxide (NO_x) emissions from fossil fuel-fired generating facilities located primarily in the Eastern United States. Following a court order to reconsider the CAIR requirements, the EPA adopted the Cross-State Air Pollution Rule (CSAPR) in July 2011 to replace CAIR with a program that would have required each of 31 Eastern states and the District of Columbia to reduce SO_2 and NO_x emissions beginning January 1, 2012. In December 2011, the United States Court of Appeals for the District of Columbia Circuit granted a request to stay the effectiveness of CSAPR, which reinstated the CAIR requirements while the court considers CSAPR.

Neither the reinstatement of CAIR nor the potential adoption of CSAPR result in a material change to our emissions reduction plan in Maryland as the magnitude and timing of the emissions reduction requirements of Maryland's HAA and Clean Power Rule (CPR) are generally consistent with the requirements of CSAPR and CAIR. However, if CSAPR is implemented, it could affect the market prices of SO_2 and NOx emission allowances, which could in turn affect our financial results.

Other NAAQS Rulemaking

In January 2010, the EPA proposed rules to adopt NAAQS for ozone that are stricter than the NAAQS adopted in March 2008, based on the EPA's reevaluation of scientific evidence about ozone and ozone's effects on humans and the environment. The final standard is not expected to be adopted before 2014.

In June 2010, the EPA adopted a stricter NAAQS for SO_2. States will need to submit plans by June 2013 demonstrating attainment of the new standard by 2017.

In September 2006, the EPA adopted a stricter NAAQS for particulate matter. States will need to submit plans in 2012 demonstrating attainment of the new standard by 2014.

We are unable to determine the impact that complying with the stricter NAAQS for ozone, SO_2, or particulate matter will have on our financial results until the states in which our generating facilities are located adopt plans to meet the new standards. However, costs associated with compliance with these plans could be material.

Section 185 Fees

In December 2006, the United States Court of Appeals for the District of Columbia Circuit ruled that requirements to impose fees on large emissions sources in areas that have not attained the NAAQS 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. Guidance issued by the EPA to the states dated January 2010 that contained flexible state alternatives to meet the Section 185 fee requirements was vacated by the court in July 2011. As a result, states in which we operate have not finalized their approach for implementing the requirements and consequently, and 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.

Mercury and Air Toxics Standards

In December 2011, the EPA established hazardous air pollutant emission standards for existing fossil fuel-fired power generating facilities. These standards establish technology-based emissions limits for mercury and other toxic air pollutants based on the emissions reductions achieved by the best performing emission sources currently in operation. Facilities subject to the new standards must achieve compliance by 2015. An additional year to achieve compliance will be available to facilities that are unable to meet the three-year deadline without adversely affecting the reliability of the United States electric system. The magnitude and timing of the emissions reduction requirements under the new standards are consistent with those under

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Maryland's HAA and CPR and, as a result, we do not expect our compliance costs to be material.

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, C.P. Crane, and H. A. Wagner plants located in Maryland. The EPA also sent similar, but narrower, information requests to Keystone and Conemaugh, two of our newer Pennsylvania 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 20.99% 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 generally consistent with existing and anticipated federal requirements. Likewise, Massachusetts has comprehensive air emissions standards in place that are more stringent than the federal standards, so impending regulations are not anticipated to cause additional costs to our natural gas and oil-fired units in Massachusetts. In Pennsylvania, regulations adopted requiring coal-fired generating facilities to reduce mercury emissions were ruled invalid by a Pennsylvania court in January 2009.

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

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 $15 million in 2012, $30 million in 2013, $35 million in 2014 and $5 million from 2015-2016.

Our estimates are subject to significant uncertainties including the timing of any additional federal and/or state regulations or legislation, the implementation timetables for such regulation or legislation, plant divestitures, 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

In response to the anticipated challenges of global climate change, we believe it is imperative to slow, stop and reverse the growth in greenhouse gas emissions. Climate change could pose physical risks, such as more frequent or more extreme weather events, that could affect our systems and operations; however, uncertainty remains as to the timing and extent of any direct, climate-related impacts to our systems and operations. Extreme weather can affect the supply of and demand for electricity, natural gas and fuels and these changes may impact the price of energy commodities in both the spot market and the forward market, which may affect our financial results. In addition, extreme weather typically increases demand for electricity and gas from BGE's customers.

There is continued likelihood that greenhouse gas emissions regulation will eventually occur at the international or federal level and/or continue to occur at the state level although considerable uncertainty remains as to the nature and timing of such regulation. Climate-related legislation was introduced in the last several United States Congress sessions but was not enacted. In September 2009, the EPA issued an "endangerment and cause or contribute finding" for greenhouse gases under the Clean Air Act and in 2010 finalized changes to its

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air construction and operating permit programs to incorporate greenhouse gases as pollutants subject to air permits. Beginning in 2011, in certain instances, additional greenhouse gas emissions resulting from the construction or modification of large facilities subject to the EPA's permit programs, which include power plants, are required to be controlled through the use of the best available control technology, as determined by the EPA, before an air emissions permit will be issued. If we were to modify our generating plants, our costs to comply with these requirements could be material depending on the modifications made. In addition, the EPA has proposed a new source performance standard for greenhouse gas emissions that, if adopted, would apply to new power generating facilities.

Maryland and Massachusetts are participants in the Northeast Regional Greenhouse Gas Initiative (RGGI). Under RGGI, the states auction carbon dioxide (CO_2) allowances associated with power plants, which include plants owned by us. Auctions have occurred quarterly since September 2008. Although we did not incur material costs in these auctions, we could incur material costs in the future to purchase allowances necessary to offset CO_2 emissions from our plants.

In addition, California has adopted regulations to implement a cap and trade program beginning in 2013 aimed at achieving a 15% reduction in CO_2 emissions by 2020 as compared with 2012. The cost of purchasing emission allowances under this program could have a material impact on our financial results depending on market prices for the allowances.

We continue to monitor international developments and proposed federal and state legislation and regulations and evaluate the potential impact on our operations. In the event that additional 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, and our compliance costs could be material.

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 has an overall CO_2 emission rate that is lower than the industry average with a substantial amount of the fleet's output coming from nuclear and hydroelectric plants, which generate significantly lower CO_2 emissions than fossil fuel plants. We also have experience trading in the markets for emissions allowances and renewable energy credits and our NewEnergy business has expertise in providing renewable energy products and services to retail customers.

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 eight 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 ruled in April 2009 that the EPA has a right to consider cost-benefit analysis in such decisions.

The EPA proposed new regulations in April 2011 and we will evaluate our compliance options in light of those proposed regulations. Until the new regulations are finalized, which is expected in July 2012, water intake compliance will be determined in accordance with the EPA's July 2007 order and relevant state regulations and interpretations. Depending on the scope of any new regulations that may be adopted by the EPA, our compliance costs could be material.

In July 2011, the New York Department of Environmental Conservation (NYDEC) released a final policy regarding the best technology available for cooling water intake structures for minimizing adverse environmental impacts. Through its policy, NYDEC established closed cycle cooling or its equivalent as the performance goal for all existing facilities but also provided that NYDEC will select a feasible technology whose costs are not wholly disproportionate to the environmental benefits to be gained and allows for a site-specific determination where the performance goal cannot be achieved. CENG submissions to the NYDEC are currently under review. Once the required technology is determined and costs can be reasonably estimated, CENG will evaluate its next steps. However, such costs could be material.

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Hazardous and Solid Waste

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 began developing or considering regulations governing the placement of ash in landfills, surface impoundments, sand/gravel surface mines and coal mines. In 2009, following the Tennessee Valley Authority ash release, the EPA announced it was considering regulating ash as a hazardous waste. In May 2010, the EPA proposed rules to regulate coal combustion residuals (CCRs), such as ash, either as a special hazardous waste or as a nonhazardous waste. The EPA plans to issue an analysis on the potential health risks from beneficial re-use of CCRs prior to issuing a final rule, which is expected at the end of 2012. In addition, the Maryland Department of the Environment finalized regulations governing the disposal, storage, use and placement of ash in December 2008. Depending on the scope of any final rules that are adopted, additional federal regulation has the potential to result in additional compliance requirements and costs that could be material.

As a result of these regulatory proposals and our current ash generation projections, we are constructing and have begun using a dedicated ash landfill for our Maryland coal-fired plants, while we continue to explore and develop beneficial use opportunities. Over the next five years, we estimate that our capital expenditures for the landfill will be approximately $20 million. Our estimates are subject to significant uncertainties, including the timing of any regulatory change, its implementation timetable, and the scope of the final federal and state 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

Constellation Energy and its consolidated subsidiaries (excluding CENG, which was deconsolidated on November 6, 2009) had approximately 7,900 employees at December 31, 2011.

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.

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 slow recovery from recession or a new 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 may continue to 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 and banking markets, as well as the periodic use of commercial paper 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. Instability or volatility 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 may be exploring. In addition, such instability or volatility 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 instability or volatility 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.

As a result of participation in wholesale and retail energy markets, our NewEnergy business may incur substantial costs and liabilities through exposure to price volatility, counterparty performance risk, and competition that could negatively impact margins.

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 our 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. In addition, new sources of natural gas supplies from domestic shale production, as well as rising liquid natural gas (LNG) exports, could increase the long-term supply of natural gas and create a fundamental and long-lasting decline in natural gas prices. Lower natural gas prices could contribute to a decline in power generation prices that could have an adverse effect on our financial results and cash flows. As a result, fuel price changes may adversely affect our financial results.

Exposure to counterparty performance. Our NewEnergy 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,

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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.

Exposure to margin and volume competition. With sustained low forward natural gas and power prices and low market volatility, overall margins have tightened as retail competitors have aggressively pursued market share and wholesale generators have used the retail channel to hedge generation output. Tightened margins could adversely affect our financial results by decreasing our overall gross margins and profitability.

Changes in the prices of commodities, initial margin requirements, collateral posting asymmetries and types of collateral impact our liquidity requirements.

Our businesses are exposed to market fluctuations in the price and transportation costs of electricity, natural gas, coal, 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 Generation and NewEnergy 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 NewEnergy business, we generally do not receive collateral under contractual obligations to supply our customers, but we may hedge these transactions through purchases 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.

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 cash collateral to us, which could adversely affect our overall liquidity and ability to finance our operations, and, in turn, could adversely affect our credit ratings. Additionally, posting letters of credit to counterparties to meet collateral requirements adversely impacts our liquidity, while the receipt of letters of credit as collateral does not improve our liquidity.

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 our operations. Over the past several years, 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 also can be adversely affected by various factors, including price volatility and the availability of credit. 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.

We may not fully hedge our Generation and NewEnergy businesses, 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.

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In addition, risk management tools and metrics such as economic value at risk, daily value at risk, and stress testing are based on historical price movements. If price movements significantly or persistently deviate from historical behavior, risk limits may not fully 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 and nonderivative 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, as well as nonderivative contracts, 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 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 derivative instruments could reflect a realized value that differs from our reported estimates of fair value.

Inaccurate assumptions and estimates in the models we use could adversely impact our financial results.

We deploy many models to value merchant contracts, derivatives and assets, to dispatch power from our generation plants, and to measure the risks and costs of various transactions and businesses. Also, a significant portion of our business relies on the assumptions underlying the forecasting of customer load, correlations between prices of energy commodities and weather and the creditworthiness of our customers and other third parties. Inaccurate estimates of various business assumptions used in those models could create the mispricing of customer contracts and assets or the incorrect measurement of key risks relating to our portfolios and businesses that could adversely impact our financial results.

Poor market performance will affect our pension plan investments, which may adversely affect our liquidity and financial results.

At December 31, 2011, our qualified pension obligation was approximately $225 million greater than the fair value of our plan assets. 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.

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

We own, operate and have ownership interests in 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 our ownership interest in nuclear generating facilities.

Through our nuclear joint venture, we indirectly own substantial interests in nuclear power plants. 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 operation of nuclear generating facilities involves 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 the insurance coverage available from both private sources and an industry retrospective payment plan. In addition, in the event of an accident at our nuclear joint venture or another participating insured party's nuclear plants, we or CENG could be assessed retrospective insurance premiums (because all nuclear plant operators contribute to a nationwide catastrophic insurance fund). In instances where CENG is the member insured, we have guaranteed our share of CENG's performance. Uninsured losses or the payment of retrospective insurance premiums could each have a material adverse effect on 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.

Examples of potential future regulatory changes include additional regulation of greenhouse gas emissions at the federal, regional, and/or state level, heightened enforcement of new source review requirements, increased regulation of coal combustion by-products, and mandated investment in maximum achievable control technology or renewable energy resources. One or more of these changes could increase our compliance and operating costs or require significant commitments of capital.

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.

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 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 competitive 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 is 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

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review or how such outcome may affect our, or BGE's financial results, but it could be material.

The Dodd-Frank Wall Street Reform and Consumer Protection Act provides for a new regulatory regime for derivatives. Final regulations may address collateral requirements, exchange margin cash postings, and other aspects of derivative transactions, which if applicable to us despite being an end user of derivatives, could require us to post additional cash collateral or otherwise have a material adverse effect on our business.

We are also subject to mandatory reliability standards enacted by the North American Electric Reliability Corporation (NERC) and enforced by the FERC. Compliance with the mandatory reliability standards may subject us to higher operating costs and may result in increased capital expenditures. If we are found to be in noncompliance with the mandatory reliability standards, we could be subject to sanctions, including substantial monetary penalties. Additionally, in 2011, the State of Maryland enacted legislation that imposed reliability and quality of service standards on electric companies and requires the Maryland PSC to enact regulations by July 1, 2012 to implement these standards.

Further, federal and/or state regulatory approval may be necessary for us to complete transactions. As part of the regulatory approval process, governmental entities may impose terms and conditions on the transaction or our business that are unfavorable or add significant additional costs to our future operations.

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 competitive segments of the electric and gas industries created by federal and state restructuring initiatives. If competitive restructuring of the electric or gas industries is amended, 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.

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. Proposals in the State of Maryland from time to time 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. In addition, other states are seeking more direct ways to affect the results of wholesale capacity markets, including through legislative or regulatory action that provides subsidies to or guaranteed cost recovery for the development of new generation in exchange for the new generation clearing in the PJM capacity market. 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 amended, reversed, discontinued, restricted, or delayed, or if legislative or regulatory 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 in Canada. As a result, we depend on transportation and transmission facilities owned and operated by utilities and other energy companies to deliver the electricity, natural gas and other related products we sell to 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.

BGE's electric and gas infrastructure may require significant expenditures to maintain and is subject to operational failure, which could result in potential liability.

Much of BGE's electric and gas operational systems and infrastructure, such as gas mains and pipelines and electric transmission and distribution equipment, has been in service for many years. Older equipment, even if maintained in accordance with good utility practices, is subject to operational failure, including due to events that are beyond BGE's control, and may require significant expenditures to operate efficiently. Operational failure could result in potential liability if such failure results in damage to property or injury to individuals. As a result, electric and gas infrastructure expenditures and operational failure of equipment could have an adverse effect on our, or BGE's, financial results.

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Our NewEnergy 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 reduced revenues and increased operating costs to our business.

Our NewEnergy 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 NewEnergy business must be prepared to supply to customers may increase our operating costs. The process of estimating the load requirements of our customers is complicated by potential variability in demand resulting from extreme changes in weather and economic factors affecting our customers. A significant under- or over-estimation of load requirements could result in our NewEnergy 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 reduce our revenues and/or 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.

Investment in new business initiatives and markets may not be successful.

Our NewEnergy business has sought to invest in new business initiatives and actively participate in new markets. These include, but are not limited to, unconventional oil and gas exploration and production, residential retail power and gas sales, solar and wind generation, and managed load response. Such initiatives may involve significant risks and uncertainties, including distraction of management from current operations, inadequate return on capital, and unidentified issues not discovered in the diligence performed prior to launching an initiative or entering a market. Additionally, as these markets mature, there may be new market entrants or expansion by established competitors that increase competition for customers and resources, which could result in us not achieving our plans and could have a material adverse effect on our financial results. In addition to our NewEnergy business, BGE faces risks associated with its Smart Grid initiative. These risks include, but are not limited to, cost recovery, regulatory concerns, cyber security and obsolescence of technology. Due to these risks, no assurance can be given that such initiatives will be successful and will not 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. Specifically, we intend to continue to pursue the acquisition of new generating plants in regions where we have significant retail and wholesale customer supply operations. Acquired plants may not generate the projected rates of return or sufficiently match generation capacity with retail and wholesale customer supply operations volumes causing an increase in collateral requirements. If we cannot identify, complete and integrate acquisitions successfully, our business, results of operations and financial condition could be adversely affected.

War, threats of terrorism and catastrophic events may impact the results of our operations in unpredictable ways.

We cannot predict the impact that any future act of war, terrorist attack, or catastrophic event might 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, war, or a catastrophic event may affect our operations. Furthermore, these catastrophic events could compromise the physical or cyber security of our facilities, which could adversely affect our ability to manage our business effectively.

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 war, threats of terrorism, and catastrophic events may affect our stock price and our ability to raise capital.

In addition, we maintain a level of insurance coverage consistent with industry practices against property and casualty losses subject to unforeseen occurrences or catastrophic events that may damage or destroy assets or interrupt operations. Furthermore, in the event of a severe disruption resulting from war, threats of terrorism, and catastrophic events, we have contingency plans and employ crisis management to respond and recover operations. Despite these measures, there may be events beyond our control that may severely impact operations and affect financial performance.

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

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 NewEnergy business, 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. 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.

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 employees, contractors, customers, and the general public may be exposed to a risk of injury due to the nature of the energy industry.

Employees and contractors throughout the organization work in, and customers and the general public may be exposed to, potentially dangerous conditions near our operations. As a result, employees, contractors, customers, and the general public may be at risk for serious injury, including loss of life. Significant risks include nuclear accidents, gas explosions, and electric contact cases.

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Because the market price of shares of Exelon common stock will fluctuate and the exchange ratio will not be adjusted to reflect such fluctuations, the merger consideration at the date of the closing may vary significantly from the date the merger agreement was executed.

Upon completion of the merger, each outstanding share of Constellation Energy common stock will be converted into the right to receive 0.93 of a share of Exelon common stock. The number of shares of Exelon common stock to be issued pursuant to the merger agreement for each share of Constellation Energy common stock will not change to reflect changes in the market price of Exelon or Constellation Energy common stock. The market price of Exelon common stock at the time of completion of the merger may vary significantly from the market prices of Exelon common stock on the date the merger agreement was executed.

In addition, we might not complete the merger until a significant period of time has passed after the respective special shareholder meetings. Because Exelon will not adjust the exchange ratio to reflect any changes in the market value of Exelon common stock or Constellation Energy common stock, the market value of the Exelon common stock issued in connection with the merger and the Constellation Energy common stock surrendered in connection with the merger may be higher or lower than the values of those shares on earlier dates. Stock price changes may result from market reaction to the announcement of the merger and market assessment of the likelihood that the merger will be completed, changes in the business, operations or prospects of Exelon or Constellation Energy prior to or following the merger, litigation or regulatory considerations, general business, market, industry or economic conditions and other factors both within and beyond the control of Exelon and Constellation Energy. Neither we nor Exelon is permitted to terminate the merger agreement solely because of changes in the market price of either company's common stock.

The merger agreement contains provisions that limit each of Exelon's and Constellation Energy's ability to pursue alternatives to the merger, which could discourage a potential acquirer of either Constellation Energy or Exelon from making an alternative transaction proposal and, in certain circumstances, could require Exelon or Constellation Energy to pay to the other a significant termination fee.

Under the merger agreement, we and Exelon are restricted, subject to limited exceptions, from entering into alternative transactions in lieu of the merger. In general, unless and until the merger agreement is terminated, both we and Exelon are restricted from, among other things, soliciting, initiating, knowingly encouraging or facilitating a competing acquisition proposal from any person. Each of the Exelon board of directors and the Constellation Energy board of directors is limited in its ability to change its recommendation with respect to the merger-related proposals. We or Exelon may terminate the merger agreement and enter into an agreement with respect to a superior proposal only if specified conditions have been satisfied, including compliance with the non-solicitation provisions of the merger agreement. These provisions could discourage a third party that may have an interest in acquiring all or a significant part of Exelon or Constellation Energy from considering or proposing such an acquisition, even if such third party were prepared to pay consideration with a higher per share cash or market value than the consideration proposed to be received or realized in the merger, or might result in a potential competing acquirer proposing to pay a lower price than it would otherwise have proposed to pay because of the added expense of the termination fee that may become payable in certain circumstances. Under the merger agreement, if the merger agreement is terminated and another acquisition proposal is accepted, we or Exelon, as applicable, may be required to pay a termination fee of $800 million in the case of a termination fee payable by Exelon to us and a termination fee of $200 million in the case of a termination fee payable by us to Exelon.

Exelon and Constellation Energy are subject to various uncertainties and contractual restrictions while the merger is pending that may cause disruption and could adversely affect their financial results.

Uncertainty about the effect of the merger on employees, suppliers and customers may have an adverse effect on us and/or Exelon. These uncertainties may impair our and/or Exelon's ability to attract, retain and motivate key personnel until the merger is completed and for a period of time thereafter, as employees and prospective employees may experience uncertainty about their future roles with the combined company, and could cause customers, suppliers and others who deal with us or Exelon to seek to change existing business relationships with us or Exelon. The pursuit of the merger and the preparation for the integration may also place a burden on management and internal resources. Any significant diversion of management attention away from ongoing business concerns and any difficulties encountered in the transition and integration process could affect our and/or Exelon's financial results.

In addition, the merger agreement restricts each of Exelon and Constellation Energy, without the other's consent, from making certain acquisitions and taking other specified actions while the merger is pending. These restrictions may prevent Exelon and/or Constellation Energy from pursuing otherwise attractive business opportunities and making other changes to their respective businesses prior to completion of the merger or termination of the merger agreement.

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If completed, the merger may not achieve its anticipated results, and Exelon and Constellation Energy may be unable to integrate their operations in the manner expected.

We entered into the merger agreement with the expectation that the merger will result in various benefits, including, among other things, cost savings and operating efficiencies. Achieving the anticipated benefits of the merger is subject to a number of uncertainties, including whether the businesses of Exelon and Constellation Energy can be integrated in an efficient, effective and timely manner.

It is possible that the integration process could take longer than anticipated and could result in the loss of valuable employees, the disruption of each company's ongoing businesses, processes and systems or inconsistencies in standards, controls, procedures, practices, policies and compensation arrangements, any of which could adversely affect the combined company's ability to achieve the anticipated benefits of the merger as and when expected. The combined company's results of operations could also be adversely affected by any issues attributable to either company's operations that arise or are based on events or actions that occur prior to the closing of the merger. The companies may have difficulty addressing possible differences in corporate cultures and management philosophies. Failure to achieve these anticipated benefits could result in increased costs or decreases in the amount of expected revenues and could adversely affect the combined company's future business, financial condition, operating results and prospects.

Pending litigation against Exelon and Constellation Energy could result in an injunction preventing the completion of the merger or a judgment resulting in the payment of damages in the event the merger is completed and may adversely affect the combined company's business, financial condition or results of operations and cash flows following the merger.

Twelve purported class action lawsuits were filed against us, each member of our board of directors, Exelon and Bolt Acquisition Corporation, a Maryland corporation and a wholly owned subsidiary of Exelon, in connection with the merger. Among other things, the lawsuits sought injunctive relief that would have prevented completion of the merger in accordance with the terms of the merger agreement. The parties to the litigation have reached a settlement that remains subject to court approval. If the settlement is not approved by the court, these lawsuits could prevent or delay completion of the merger and result in substantial costs to us and Exelon, including any costs associated with the indemnification of directors and officers. Plaintiffs may file additional lawsuits against us, Exelon and/or the directors and officers of either company in connection with the merger. The defense or settlement of any lawsuit or claim that remains unresolved at the time the merger is completed may adversely affect the combined company's business, financial condition, results of operations and cash flows.

The merger is subject to the receipt of consent or approval from governmental entities that could delay the completion of the merger or impose conditions that could have a material adverse effect on the combined company or that could cause abandonment of the merger.

Completion of the merger remains conditioned upon the receipt of consents, orders, approvals or clearances from the Federal Energy Regulatory Commission, the Nuclear Regulatory Commission (NRC), and the Maryland PSC. The special meetings of the shareholders of Exelon and Constellation Energy at which the proposals required to complete the merger were considered took place before all of the required regulatory approvals had been obtained and before all conditions to such approvals, if any, were known.

We and Exelon may subsequently agree to conditions without seeking further shareholder approval, such as the settlement agreements reached in December 2011 and January 2012, even if such conditions could have an adverse effect on us, Exelon, or the combined company.

We cannot provide assurance that we and Exelon will obtain all required regulatory consents or approvals or that these consents or approvals will not contain terms, conditions or restrictions that would be detrimental to the combined company after the completion of the merger. The merger agreement generally permits each party to terminate the merger agreement if the final terms of any of the required regulatory consents or approvals require (1) any action that involves divesting, holding separate or otherwise transferring control over any nuclear or hydroelectric or pumped-storage generation assets of the parties or any of their respective subsidiaries or affiliates; or (2) any action (including any action that involves divesting, holding separate or otherwise transferring control over base-load capacity), without including those actions proposed by the parties' mutually agreed-upon analysis of mitigation to address the increased market concentration resulting from the merger and the concessions announced by the parties in the press release announcing the merger agreement, which would, individually or in the aggregate, reasonably be expected to have a material adverse effect on either party. Any substantial delay in obtaining satisfactory approvals, receipt of proceeds from required divestitures in an amount substantially lower than anticipated or the imposition of any terms or conditions in connection with such approvals could cause a material reduction in the expected benefits of the merger. If any such delays or conditions are serious enough, the parties may decide to abandon the merger.

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If completed, the merger may adversely affect the combined company's ability to attract and retain key employees.

Current and prospective Exelon and Constellation Energy employees may experience uncertainty about their future roles at the combined company following the completion of the proposed merger. In addition, current and prospective Exelon and Constellation Energy employees may determine that they do not desire to work for the combined company for a variety of possible reasons. These factors may adversely affect the combined company's ability to attract and retain key management and other personnel.

Failure to complete the merger could negatively affect our share price and our future business and financial results.

Completion of the merger is not assured and is subject to risks, including the risks that approval of the transaction by shareholders of Exelon and Constellation Energy or by governmental agencies will not be obtained or that certain other closing conditions will not be satisfied. If the merger is not completed, our ongoing business may be adversely affected and we will be subject to several risks, including:

- having to pay certain significant costs relating to the merger without receiving the benefits of the merger, including, in certain circumstances, a termination fee of $200 million to Exelon;
- the potential loss of key personnel during the pendency of the merger as employees may experience uncertainty about their future roles with the combined company;
- we will have been subject to certain restrictions on the conduct of our business, which may have prevented us from making certain acquisitions or dispositions or pursuing certain business opportunities while the merger is pending; and
- our share price may decline to the extent that the current market prices reflect an assumption by the market that the merger will be completed.

Exelon and Constellation Energy may incur unexpected transaction fees and merger-related costs in connection with the merger.

We and Exelon expect to incur a number of non-recurring expenses, totaling approximately $150 million, associated with completing the merger, as well as expenses related to combining the operations of the two companies. The combined company may incur additional unanticipated costs in the integration of the businesses of Exelon and Constellation Energy. Although we expect that the elimination of certain duplicative costs, as well as the realization of other efficiencies related to the integration of the two businesses, will offset the incremental transaction and merger-related costs over time, the combined company may not achieve this net benefit in the near term, or at all.

Current Constellation Energy stockholders will have a reduced ownership and voting interest after the merger.

Exelon will issue or reserve for issuance approximately 201.9 million shares of Exelon common stock to Constellation Energy stockholders in the merger (including shares of Exelon common stock issuable pursuant to Constellation Energy stock options and other equity-based awards). Based on the number of shares of common stock of Exelon and Constellation Energy outstanding on October 7, 2011, the record date for the two companies' special meetings of shareholders to approve the merger, upon the completion of the merger, former Constellation Energy stockholders would own approximately 22% of the outstanding shares of Exelon common stock immediately following the consummation of the merger.

Constellation Energy stockholders currently have the right to vote for our directors and on other matters affecting us. When the merger occurs, each Constellation Energy stockholder who receives shares of Exelon common stock will become a shareholder of Exelon with a percentage ownership of the combined company that will be smaller than the shareholder's percentage ownership of Constellation Energy.

As a result, former Constellation Energy stockholders will have less voting power in the combined company than they now have with respect to Constellation Energy.

Following the merger, Constellation Energy stockholders will own equity interests in a company that owns and operates a relatively higher proportion of nuclear generating facilities, which can present unique risks.

Exelon's ownership interest in and operation of a relatively higher proportion of nuclear facilities than Constellation Energy subjects Exelon to increased associated risks, including the potential harmful effects on the environment and human health resulting from the operation of nuclear facilities and the storage, handling and disposal of radioactive materials; limitations on the amounts and types of insurance commercially available to cover losses that might arise in connection with nuclear operations; uncertainties with respect to the technological and financial aspects of decommissioning nuclear plants at the end of their licensed lives; and costs associated with regulatory oversight by the NRC, including NRC imposed fines, lost revenues as a result of any NRC ordered shutdown of Exelon nuclear facilities, or increased capital costs as a result of increased NRC safety and security regulations, including any new requirements as a result of the NRC's review of the accident at the Fukushima

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nuclear power plant in Japan. As shareholders of Exelon following the merger, Constellation Energy stockholders may be adversely affected by these risks to a greater extent than they were prior to the merger.

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 16,640 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 NewEnergy business owns several natural gas producing properties.

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The following table describes our generating facilities:

		At December 31, 2011				
Plant	Location	Capacity (MW)	% Owned	Capacity Owned (MW)	2011 Capacity Factor (%) *	Primary Fuel
Calvert Cliffs Unit 1 (1)	Calvert Co., MD	855	50.0	428	100.9	Nuclear
Calvert Cliffs Unit 2 (1)	Calvert Co., MD	850	50.0	425	91.7	Nuclear
Nine Mile Point Unit 1 (1)	Scriba, NY	628	50.0	314	84.0	Nuclear
Nine Mile Point Unit 2 (1)	Scriba, NY	1,141	41.0	468	95.4	Nuclear
R.E. Ginna (1)	Ontario, NY	581	50.0	291	84.7	Nuclear
Brandon Shores (2)	Anne Arundel Co., MD	1,273	100.0	1,273	52.6	Coal
H. A. Wagner (2)	Anne Arundel Co., MD	976	100.0	976	18.0	Coal/Oil/Gas
C. P. Crane (2)	Baltimore Co., MD	399	100.0	399	27.8	Oil/Coal
Keystone	Armstrong and Indiana Cos., PA	1,711	21.0	359(5)	74.0	Coal
Conemaugh	West Moreland Co., PA	1,711	10.6	181(5)	71.5	Coal
Perryman	Harford Co., MD	347	100.0	347	2.0	Oil/Gas
Riverside	Baltimore Co., MD	228	100.0	228	1.0	Oil/Gas
Handsome Lake	Rockland Twp, PA	268	100.0	268	1.9	Gas
Notch Cliff	Baltimore Co., MD	101	100.0	101	2.3	Gas
Westport	Baltimore Co., MD	116	100.0	116	0.0	Gas
Gould Street	Baltimore City, MD	97	100.0	97	2.5	Gas
Philadelphia Road	Baltimore Co., MD	61	100.0	61	0.8	Oil
Safe Harbor	Safe Harbor, PA	417	66.7	278	44.9	Hydro
Criterion	Oakland, MD	70	100.0	70	32.4	Wind
Grande Prairie	Alberta, Canada	93	100.0	93	20.6	Gas
West Valley	Salt Lake City, UT	200	100.0	200	10.3	Gas
Hillabee Energy Center	Alexander City, Alabama	740	100.0	740	64.3	Gas
Colorado Bend Energy Center	Wharton, Texas	550	100.0	550	31.6	Gas
Quail Run Energy Center	Odessa, Texas	550	100.0	550	14.1	Gas
Mystic 7	Charlestown, MA	560	100.0	560	2.0	Oil/Gas
Mystic 8	Charlestown, MA	703	100.0	703	75.8	Gas
Mystic 9	Charlestown, MA	695	100.0	695	74.8	Gas
Fore River	North Weymouth, MA	688	100.0	688	79.3	Gas
Mystic Jet	Charlestown, MA	9	100.0	9	0.1	Oil
Panther Creek	Nesquehoning, PA	80	50.0	40	98.0	Waste Coal
Colver	Colver Township, PA	102	25.0	26	99.8	Waste Coal
Sunnyside	Sunnyside, UT	51	50.0	26	93.6	Waste Coal
ACE	Trona, CA	102	31.1	32	87.5	Coal
Jasmin	Kern Co., CA	35	50.0	18	94.9	Coal
POSO	Kern Co., CA	35	50.0	18	73.6	Coal
Rocklin	Placer Co., CA	24	50.0	12	86.7	Biomass
Fresno	Fresno, CA	24	50.0	12	91.9	Biomass
Chinese Station	Jamestown, CA	22	45.0	10	70.7	Biomass

Malacha	Muck Valley, CA	32	50.0	16	37.4	Hydro
Constellation Solar (6)	Various	69	100.0	69		Solar
SEGS IV	Kramer Junction, CA	33	12.2	4	26.0	Solar
SEGS V	Kramer Junction, CA	24	4.2	1	37.8	Solar
SEGS VI	Kramer Junction, CA	34	8.8	3	28.1	Solar
Total Generating Facilities (3)(4)		17,284		11,751		

*
The capacity factors are based on installed capacity which is temperature adjusted. Therefore, it is possible to generate more than 100% of the installed capacity.

(1)
We own a 50.01% membership interest in CENG, the joint venture with EDF that holds these nuclear generating assets as a result of the sale of a 49.99% interest in CENG to EDF that was completed in November 2009. We discuss this transaction in more detail in Note 2 to Consolidated Financial Statements.

(2)
The generating facilities that we agreed to sell within six months of merger close with Exelon.

(3)
The sum of the individual plant capacity megawatts may not equal the total due to the effects of rounding.

(4)
Capacity figures represent summer seasonal claimed capacity amounts. For units with power purchase agreements, we use the contract capacity.

(5)
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.

(6)
Constellation Solar is our operation that constructs, owns, and operates solar facilities at various customer locations.

In December 2009, we were selected by the State of Maryland to develop an approximately 17 MW solar photovoltaic power installation in Emmitsburg, Maryland. This $60 million solar facility will be constructed, owned, operated and maintained by us. We expect the project to be completed by December 2012.

As of December 31, 2011, we also have a 50% ownership interest in a waste coal processing facility located in Hazelton, Pennsylvania.

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Item 3. Legal Proceedings

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

Item 4. Mine Safety Disclosure

Not Applicable.

Executive Officers of the Registrant

Name	Age	Present Office	Other Offices or Positions Held During Past Five Years
Mayo A. Shattuck III	57	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
Henry B. Barron	61	Executive Vice President of Constellation Energy (since April 2008); and President and Chief Executive Officer (since September 2008) of Constellation Energy Nuclear Group	Chief Nuclear Officer of Constellation Energy Nuclear Group; and Group Executive and Chief Nuclear Officer Duke Energy
James L. Connaughton	50	Executive Vice President, Corporate Affairs, Public and Environmental Policy of Constellation Energy (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	60	Senior Vice President (since January 2004) and Chief Environmental Officer (since June 2007) of Constellation Energy	None
Charles A. Berardesco	53	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	47	Senior Vice President and Chief Risk Officer of Constellation Energy (since January 2008)	Global Head of Strategy and Global Head of Derivative Services, Alternative Investment Services and Head of Treasury Services Risk Management J.P. Morgan Chase & Company
Kenneth W. DeFontes, Jr.	61	Senior Vice President of Constellation Energy (since October 2004); and President and Chief Executive Officer of Baltimore Gas and Electric Company (since October 2004)	None
Andrew L. Good	44	Senior Vice President, Corporate Strategy and Development of Constellation Energy (since November 2009)	Senior Vice President and Chief Financial Officer Constellation Energy Resources; Senior Vice President and Chief Financial Officer Constellation Energy Commodities Group; and Senior Vice President, Finance Constellation Energy
Kathleen W. Hyle	53	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
Mary L. Lauria	47	Senior Vice President and Chief Human Resources Officer of Constellation Energy (since October 2010)	Vice President and Chief Talent Officer Constellation Energy; Vice President, Talent Management and Leadership Development Wyeth; and Director, Global Talent Management Johnson & Johnson
Jonathan W. Thayer	40	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 officer and any other person pursuant to which the officer was selected.

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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 31, 2012, there were 29,908 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, unless Constellation Energy elects to defer interest payments on the 8.625% Series A Junior Subordinated Debentures due June 15, 2063, and any deferred interest remains unpaid. The merger agreement with Exelon prohibits us from increasing our common stock dividend without Exelon's consent.

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 October 2011, we announced a quarterly dividend of $0.24 per share payable April 2, 2012 to holders of record at the close of business on March 12, 2012. This is equivalent to an annual rate of $0.96 per share. If the pending merger with Exelon closes on or before March 12, 2012, the dividend will be pro-rated, with shareholders receiving $0.00264 per share per day starting December 13, 2011 and ending the day before the merger closes. In February 2012, we announced a quarterly dividend of $0.24 per share payable July 2, 2012 to holders of record at the close of business on June 11, 2012. If the pending merger with Exelon closes after March 12, 2012, but on or before June 11, 2012, the dividend will be pro-rated, with shareholders receiving $0.00264 per share per day starting March 13, 2012 and ending the day before the merger closes. In accordance with the merger agreement, a pro-rata dividend ensures that shareholders continue to receive dividends at the current rate until the closing of the merger. This pro-rata dividend, which is the daily equivalent of $0.24 per share for the full quarter, would be paid within 30 days after the closing of the pending merger with Exelon.

Quarterly dividends were declared on our common stock during 2011 and 2010 in the amounts set forth below.

BGE pays dividends on its common stock after its Board of Directors declares them. However, pursuant to the order issued by the Maryland PSC on October 30, 2009 in connection with its approval of the transaction with EDF, BGE cannot pay common dividends to Constellation Energy if (a) after the dividend payment, BGE's equity ratio would be below 48% as calculated under the Maryland PSC's ratemaking precedents or (b) BGE's senior unsecured credit rating is rated by two of the three major credit rating agencies below investment grade. There are no other 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

	2011			2010		
	Dividend Declared	Price High	Price Low	Dividend Declared	Price High	Price Low
First Quarter	$ 0.24	$ 33.19	$ 29.70	$ 0.24	$ 36.99	$ 31.08

Second Quarter		0.24	38.09	30.92		0.24	38.73	32.09
Third Quarter		0.24	40.13	33.84		0.24	35.10	28.21
Fourth Quarter		0.24	40.97	35.03		0.24	33.18	27.64
Total	$	0.96			$	0.96		

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

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 per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans and Programs (at month end)
October 1 - October 31, 2011		$		
November 1 - November 30, 2011	104	39.52		
December 1 - December 31, 2011	62,780	39.77		
Total	62,884	$ 39.76		

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

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Item 6. Selected Financial Data

Constellation Energy Group, Inc. and Subsidiaries

	2011	2010	2009	2008	2007
	(In millions, except per share amounts)				
Summary of Operations					
Total Revenues	**$ 13,758.2**	$ 14,340.0	$ 15,598.8	$ 19,741.9	$ 21,185.1
Total Expenses	**14,126.1**	15,853.8	14,588.5	20,821.9	19,858.8
Equity investment earnings (losses)	**19.8**	25.0	(6.1)	76.4	8.1
Gain on U.S. Department of Energy Settlements	**93.8**				
Gain on Sale of Interest in CENG			7,445.6		
Net Gain (Loss) on Divestitures	**57.3**	245.8	(468.8)	25.5	
(Loss) Income From Operations	**(197.0)**	(1,243.0)	7,981.0	(978.1)	1,334.4
Gains on Sales of CEP LLC equity					63.3
Other (Expense) Income	**(75.3)**	(76.7)	(140.7)	(69.5)	157.4
Fixed Charges	**265.4**	277.8	350.1	349.1	292.4
(Loss) Income Before Income Taxes	**(537.7)**	(1,597.5)	7,490.2	(1,396.7)	1,262.7
Income Tax (Benefit) Expense	**(230.9)**	(665.7)	2,986.8	(78.3)	428.3
(Loss) Income from Continuing Operations	**(306.8)**	(931.8)	4,503.4	(1,318.4)	834.4
Loss from Discontinued Operations, Net of Income Taxes					(0.9)
Net (Loss) Income	**$ (306.8)**	$ (931.8)	$ 4,503.4	$ (1,318.4)	$ 833.5
Net Loss (Income) Attributable to Noncontrolling Interests and BGE Preference Stock Dividends	**33.5**	50.8	60.0	(4.0)	12.0
Net (Loss) Income Attributable to Common Stock	**$ (340.3)**	$ (982.6)	$ 4,443.4	$ (1,314.4)	$ 821.5
(Loss) Earnings Per Common Share from Continuing Operations Assuming Dilution	**$ (1.70)**	$ (4.90)	$ 22.19	$ (7.34)	$ 4.51
Loss from Discontinued Operations					(0.01)
(Loss) Earnings Per Common Share Assuming Dilution	**$ (1.70)**	$ (4.90)	$ 22.19	$ (7.34)	$ 4.50
Dividends Declared Per Common Share	**$ 0.96**	$ 0.96	$ 0.96	$ 1.91	$ 1.74
Summary of Financial Condition					
Total Assets	**$ 19,412.6**	$ 20,018.5	$ 23,544.4	$ 22,284.1	$ 21,742.3
Current Portion of Long-Term Debt	**$ 174.9**	$ 305.3	$ 56.9	$ 2,591.5	$ 380.6
Capitalization:					
Long-Term Debt	**$ 4,844.8**	$ 4,448.8	$ 4,814.0	$ 5,098.7	$ 4,660.5
Noncontrolling Interests	**116.9**	88.8	75.3	20.1	19.2
BGE Preference Stock Not Subject to Mandatory Redemption	**190.0**	190.0	190.0	190.0	190.0
Common Shareholders' Equity	**7,093.9**	7,829.2	8,697.1	3,181.4	5,340.2
Total Capitalization	**$ 12,245.6**	$ 12,556.8	$ 13,776.4	$ 8,490.2	$ 10,209.9

Financial Statistics at Year End					
Ratio of Earnings to Fixed Charges	**N/A**	N/A	14.76	N/A	3.84
Book Value Per Share of Common Stock	**$ 35.17**	$ 39.19	$ 43.27	$ 15.98	$ 29.93

N/A Calculation is not applicable as a result of the net losses for 2011, 2010 and 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

	2011	2010	2009	2008	2007
			(In millions)		
Summary of Operations					
Total Revenues	**$ 2,993.1**	$ 3,461.7	$ 3,579.0	$ 3,703.7	$ 3,418.5
Total Expenses	**2,678.3**	3,107.5	3,310.6	3,521.2	3,084.2
Income From Operations	**314.8**	354.2	268.4	182.5	334.3
Other Income	**21.0**	20.8	25.4	29.6	26.9
Fixed Charges	**126.6**	130.3	139.3	139.9	125.3
Income Before Income Taxes	**209.2**	244.7	154.5	72.2	235.9
Income Taxes	**73.5**	97.1	63.8	20.7	96.0
Net Income	**135.7**	147.6	90.7	51.5	139.9
Preference Stock Dividends	**13.2**	13.2	13.2	13.2	13.2
Net Income Attributable to Common Stock before Noncontrolling Interests	**$ 122.5**	$ 134.4	$ 77.5	$ 38.3	$ 126.7
Net Loss (Income) Attributable to Noncontrolling Interests			7.3		(0.1)
Net Income Attributable to Common Stock	**$ 122.5**	$ 134.4	$ 84.8	$ 38.3	$ 126.6
Summary of Financial Condition					
Total Assets	**$ 6,987.0**	$ 6,667.3	$ 6,453.1	$ 6,086.2	$ 5,783.0
Current Portion of Long-Term Debt	**$ 172.5**	$ 81.7	$ 56.5	$ 90.0	$ 375.0
Capitalization					
Long-Term Debt	**$ 2,185.9**	$ 2,059.9	$ 2,141.4	$ 2,197.7	$ 1,862.5
Noncontrolling Interest			17.6	16.9	16.8
Preference Stock Not Subject to Mandatory Redemption	**190.0**	190.0	190.0	190.0	190.0
Common Shareholder's Equity	**2,110.7**	2,073.2	1,938.8	1,538.2	1,671.7
Total Capitalization	**$ 4,486.6**	$ 4,323.1	$ 4,287.8	$ 3,942.8	$ 3,741.0
Financial Statistics at Year End					
Ratio of Earnings to Fixed Charges	**2.56**	2.80	2.07	1.50	2.84
Ratio of Earnings to Fixed Charges and Preferred and Preference Stock Dividends	**2.22**	2.41	1.80	1.33	2.42

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

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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 and joint ventures organized around three business segments: a generation business (Generation), a customer supply business (NewEnergy), 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 2011, 2010, and 2009. 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, 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

Our strategy is to provide innovative and risk-mitigating energy products and solutions to North American wholesale and retail customers. Overall, we strive to serve our customers with diverse products and solutions to meet their energy needs.

In executing this strategy, we leverage our core strengths of:

- maintaining and growing strong and diverse supply relationships with retail and wholesale customers,
- owning, developing, operating, and contracting for generation assets,
- integrating our expertise in managing physical and financial risks, and
- providing reliable, regulated utility service to customers.

Our NewEnergy business focuses on sales of electricity, natural gas, and related products and solutions to various customers, including distribution utilities, municipalities, cooperatives, and commercial, industrial, governmental, and residential customers in competitive markets. The retail NewEnergy customer supply operation combines a unified sales force with a customer-centric model that leverages technology to broaden the range of products and solutions we offer, which we believe promotes stronger customer relationships. This model focuses on efficiency and cost reduction, which we believe will provide a platform that is scalable and able to capitalize on opportunities for future growth.

NewEnergy obtains energy from both owned and contracted supply resources and actively manages these physical and contractual assets in order to derive incremental value. Additionally, NewEnergy is involved in the development, exploration, exploitation, and harvesting of natural gas properties.

Our Generation business has a fleet of plants that is strategically located in markets that support our customer-facing business and includes various fuel types, such as coal, natural gas, oil, nuclear, and renewable sources. We generally have load obligations greater than our generation output. Going forward, we intend to invest in generation assets in the markets where we serve load to provide a more efficient and balanced profile between our generation production and our customer load obligations. One of the expected benefits of our merger with Exelon is the combination of Exelon's large, environmentally advantaged generation fleet and our customer-facing business. This combination is expected to create a platform for growth and enhance our ability to service our load obligations with this generation output, thus reducing our costs.

Our strategy is enabled by a fleet of generation facilities and our risk management capabilities. This combination of our Generation and NewEnergy businesses also allows us to operate in a manner so we can minimize our collateral requirements. We discuss our collateral requirements in the *Collateral* section.

BGE, our regulated utility located in central Maryland, provides standard offer service and distributes electricity and gas to customers. BGE is also focusing on enhancing reliability and customer satisfaction, and is implementing customer demand response initiatives, including a comprehensive smart grid initiative and a full portfolio of conservation programs.

The ability of energy consumers to choose their supplier, regulatory change, and energy market conditions significantly impact our business. In response, we regularly evaluate our strategies to improve our competitive position. We actively anticipate and adapt to the business environment and regulatory changes that impact our industry. We are committed to maintaining a strong balance sheet and investment-grade credit quality by making disciplined investment and capital management decisions to support our strategic initiatives in an efficient and effective manner.

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.

In 2009, 2010, and 2011 markets in which we operate were affected by declining prices for power, gas, and capacity. We discuss the impact of declining commodity prices on our future earnings in more detail in the *Generation Results* section.

Competition also impacts our business. We discuss competition in more detail in *Item 1. Business Competition* section.

The impacts of electric competition 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 competition, which we discuss in *Item 1. Business Baltimore Gas and Electric Company Electric 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 shown on customer billings as separate components for delivery service (i.e. base rates), electric supply (commodity charge and transmission), and certain taxes and surcharges. The rates for BGE's regulated gas business continue to consist of a delivery charge (base rates as well as certain taxes and surcharges) and a commodity charge.

New Electric Generation

In September 2011, the Maryland PSC issued a notice requiring regulated electric distribution companies to issue a request for proposals for the construction of new electric generation. Under the proposal, the electric distribution companies would enter into long-term contract-for-difference arrangements, under which the electric distribution companies would pay a fixed contract price in exchange for the variable market price. The requests for proposals were issued by electric distribution companies, including BGE, in October 2011 with initial proposals due January 20, 2012. The Maryland PSC held a hearing in January 2012 to determine whether new generation is needed to meet the long-term, anticipated demand in Maryland and, if so, the amount of generation that is needed. Following the determination of the need for new generation, the Maryland PSC will select and approve the winning offers by the second quarter of 2012. The Maryland PSC established this schedule in order to preserve a possible offering of new generation capacity in the May 2012 PJM capacity auction for the 2015 - 2016 delivery years. Depending on the outcome of this process, a requirement that BGE enter into such long-term arrangements could have a material effect on our, or BGE's, financial results.

Purchase of Supplier Receivables

Effective July 15, 2010, BGE, pursuant to Maryland PSC requirements, began to purchase receivables at a discount from third party competitive energy suppliers that provide our customers electricity and/or gas. The discount rate applied to the receivables is a regulated rate which is intended to cover BGE's costs associated with purchasing these receivables, such as uncollectibles, and is subject to an annual true-up to reflect actual costs.

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.

On December 6, 2010, the Maryland PSC issued an abbreviated order authorizing BGE to increase electric distribution rates by no more than $31.0 million and increase gas distribution rates by no more than $9.8 million for service rendered on or after December 4, 2010. The electric distribution rate increase was based upon an 8.06% rate of return with a 9.86% return on equity and a 52% equity ratio. The gas distribution rate increase was based upon a 7.90% rate of return with a 9.56% return on equity and a 52% equity ratio. In March 2011, the Maryland PSC issued a comprehensive rate order setting forth the details of the decision contained in its abbreviated electric and gas distribution rate order issued in December 2010.

Revenue Decoupling

The Maryland PSC has allowed us to record a monthly adjustment to our electric distribution revenues from residential and small commercial customers since 2008 and for the majority of our large commercial and industrial customers since February 2009 to eliminate the effect of abnormal weather and usage patterns per customer on our electric distribution volumes, thereby recovering a specified dollar amount of distribution revenues per customer, by customer class, regardless of changes in consumption levels. This means BGE recognizes revenues at Maryland PSC-approved levels per customer, regardless of what actual distribution volumes were for a billing period. Therefore, while these revenues are affected by customer growth, they will not be affected by actual weather (except as discussed below with respect to major storms) or usage conditions. We then bill or credit impacted customers in subsequent months for the difference between approved revenue levels under revenue decoupling and actual customer billings. We have a similar revenue decoupling mechanism in our gas business.

In January 2012, the Maryland PSC issued an order prospectively prohibiting Maryland electric utilities with a revenue decoupling mechanism from collecting a certain portion of decoupling revenue during major storm events if customer service is not restored within a specified period of time. We do not expect the impact of this prohibition to have a material effect on our, or BGE's, financial results.

Demand Response and Advanced Metering Programs

BGE defers costs associated with its demand response programs as a regulatory asset and recovers these costs from customers in future periods.

In August 2010, the Maryland PSC approved a comprehensive smart grid initiative for BGE which includes the planned installation of 2 million residential and commercial electric and gas smart meters at an expected total cost of approximately $480 million. The Maryland PSC's approval ordered BGE to defer the associated incremental costs, depreciation and amortization, and an appropriate return, in a regulatory asset until such time as a cost-effective advanced metering system is delivered to customers. Under a grant from the United States Department of Energy (DOE) BGE is a recipient of $200 million in federal funding for its smart grid and other related initiatives. This grant allows BGE to be reimbursed for smart grid and other expenditures up to $200 million, substantially reducing the total cost of these initiatives. As of December 31, 2011, we have received $95.3 million of the $200 million grant from the DOE.

We discuss BGE's electric load management programs in more detail in *Item 1. Business Baltimore Gas and Electric Company Electric Load Management*. We discuss the associated regulatory assets in *Note 6 to Consolidated Financial Statements.*

Electric Standard Offer Service

BGE is obligated by the Maryland PSC 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. However, BGE is required to provide all residential electric customers a credit for the residential return component of the administrative fee. This credit will be given to customers through December 31, 2016. Currently, BGE is involved in a Maryland PSC proceeding to determine the future, on-going structure of the SOS administrative fee charged to all SOS customers.

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* section and in *Note 6 to Consolidated Financial Statements.*

Potential Reliability and Quality of Service Standards

During its 2011 legislative session, the Maryland General Assembly passed legislation:

- directing the Maryland PSC to enact service quality and reliability regulations by July 1, 2012 relating to the delivery of electricity to retail electric customers,
- increasing existing penalties for failure to meet these and other Maryland PSC regulations, and
- directing the Maryland PSC to undertake certain studies addressing utility liability for certain customer damages, electric utility service restoration plans, and modifications to existing revenue decoupling mechanisms for extended service interruptions.

In May 2011, the Governor signed this legislation into law and the Maryland PSC has instituted a rulemaking proceeding to draft the required service quality and reliability regulations. Once the regulations are enacted, the costs incurred by BGE to comply with them will affect our, and BGE's, financial results.

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 a number of orders covering various new transmission investment projects since 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, Texas, 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 Generation and NewEnergy businesses participate 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

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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. In May 2010, FERC issued an order approving in part and reversing in part the ALJ decision. The FERC order results in additional SECA liabilities being imposed on us. In June 2010, we filed requests for rehearing of the FERC order on the ALJ decision, as did other interested parties. In July 2010, BGE filed a petition for review of FERC's approval of the SECA methodology. In the interim, PJM and MISO have made filings at FERC to comply with the May 2010 decision and to impose charges accordingly. In October 2011, FERC denied our requests for rehearing of its May 2010 decision. In November 2011, we filed petitions for review of that decision in the U.S. Court of Appeals for the District of Columbia Circuit. The District of Columbia Circuit consolidated the BGE petitions, our petition, and the petitions of other parties in the SECA proceeding. Depending on the ultimate outcome, the proceeding may have a material effect on our financial results.

Capacity Markets

In general, capacity market design revisions are routinely proposed and considered on an ongoing basis. Such changes are subject to FERC's review and approval. Currently, we cannot predict the outcome of these proceedings or the possible effect on our, or BGE's, financial results.

Through 2008 and 2009, PJM made several filings at FERC proposing various revisions to its capacity market, or Reliability Pricing Model (RPM), including the determination of the cost-of-new-entry (CONE), which is an important component in determining the price paid to capacity resources in PJM. PJM also proposed revisions relating to the participation of energy efficiency and demand resources, and market power and mitigation rules. Some of these matters are still pending at FERC. While recent RPM design changes have not yet had a material effect on our financial results, we cannot predict the outcome of the issues still pending or on any capacity market design changes that result from new regulatory requirements. Such changes could have a material impact on our financial results.

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 requested 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. FERC dismissed the complaint and denied rehearing, and ultimately the Maryland PSC and New Jersey Board of Public Utilities appealed the case to the United States Court of Appeals for the District of Columbia. In February 2011, the court denied the petition for review and held that FERC adequately explained why the RPM auction structure was just and reasonable. The petitioners did not appeal the court's decision to the United States Supreme Court and therefore FERC's decision in our favor is final and non-appealable.

In April 2009, the Attorney General of Connecticut, the Connecticut Department of Public Utilities and Office of Consumer Counsel (together, the Connecticut Parties) filed complaints at FERC alleging improper energy bidding behavior since December 1, 2006 by generators located in New York that also received capacity payments within ISO-New England. In May 2009, the Connecticut Parties filed an amended complaint asserting that Constellation Energy Commodities Group, Inc. (CCG) and others received capacity payments while never intending to perform as capacity resources. The revised allegations assert that certain generators engaged in "economic withholding" by submitting energy bids at or near the offer cap. Since December 2006, CCG has received approximately $7 million in payments for capacity offered into ISO-New England associated with Constellation Energy's previously wholly owned nuclear facilities located in NY. In August 2009, FERC issued an order setting this matter for a public hearing before an ALJ to determine the intent of the capacity suppliers (including CCG) in making their energy offers in ISO-New England. CCG actively participated in the proceeding, and in September 2010 the ALJ issued an Initial Decision finding that the Connecticut Parties failed to prove their case and dismissed the complaint against CCG. The Initial Decision was approved by FERC and FERC denied a rehearing of the Connecticut Parties in January 2012. The Connecticut Parties have 60 days to seek a petition

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of the FERC ruling in a Circuit Court of Appeals of the United States.

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, both in the states and 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.

In addition to legal challenges to capacity markets and regulatory advocacy before FERC seeking to revise the capacity market structures, states are seeking more direct ways to affect the results of wholesale capacity markets. In January 2011, the New Jersey legislature adopted legislation that would provide for guaranteed cost recovery for the development of up to 2,000 MWs of new base load or mid-merit generation in exchange for the requirement that the new generation clear in the PJM capacity market. Similarly, the Maryland PSC issued a draft Request for Proposals that, subject to an evidentiary hearing confirming the reliability need for such resources, contemplates having Maryland ratepayers fund the development of new generation and to require that eligible new generation clear in the PJM capacity market. Such state efforts are intended to depress capacity prices, and are subject to legal and regulatory challenge. Depending on the outcome of these challenges, these state efforts could have a material effect on our financial results.

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 and cyber-security 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.

Concerns over the security of the country's energy infrastructure could lead to additional future rules or regulations related to the operation and security requirements of our generating facilities and electric and gas transmission and distribution systems, which could have a material impact on our operations and financial results.

Financial Regulatory Reform

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

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

Market Oversight

Regulatory agencies that have jurisdiction over our businesses, including the FERC and the Commodity Future Trading Commission (CFTC), possess broad enforcement and investigative authority to ensure well-functioning markets and to prohibit market manipulation or violations of the agencies' rules or orders. These agencies also possess significant civil penalty authority, including in the case of FERC and the CFTC, the authority to impose a penalty of up to $1 million per day per violation. We are committed to a culture of compliance and ensuring compliance with all applicable rules, laws and orders. Nonetheless, the regulatory agencies engage in either public or non-public investigations in response to allegations of wrongdoing and we may be involved in certain market activities that become subject to investigations. Even where no wrongdoing is found, the process of participating in a regulatory investigation could have a material effect on our business.

Weather

Generation and NewEnergy Businesses

Weather conditions in the different regions of North America influence the financial results of our Generation and NewEnergy businesses. 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

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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 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 NewEnergy 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,
- international supply and demand, and
- general economic conditions.

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,
- state and local environmental regulations,
- local transportation systems, and
- the nature and extent of electricity competition.

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 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 accounting policies discussed below 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 primarily to manage commodity price risk as well as interest rate risk. Because of the extensive nature of the accounting requirements that govern both accounting treatment and documentation, as well as the complexity of the transactions within the scope of these requirements, management is required to exercise judgment in several areas, including the following:

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

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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 the derivative accounting requirements, failure to meet these requirements, even inadvertently, could require the use of a different accounting treatment for the affected transactions. In addition, future changes in accounting requirements 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 or if they contain embedded derivatives. Identifying derivatives requires us to exercise judgment in interpreting the definition of a derivative and applying that definition to each individual contract. If a contract is not a derivative, we cannot apply derivative accounting treatment, 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 derivative accounting, 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

There are several permissible accounting treatments for derivatives. Mark-to-market is 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, both at the time of designation and on an ongoing basis.

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	Derivative asset or liability recorded at fair value	Changes in fair value recognized in earnings
Cash flow hedge	Derivative asset or liability 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	Derivative asset or liability recorded at fair value Book value of hedged asset or liability adjusted for changes in its fair valuec	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	Changes in fair value not recognized in earnings
Accounts receivable or accounts payable recorded when derivative settles	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, 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 on a net basis.

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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, we are not required to designate and account for all such contracts identically. We generally elect NPNS accrual or hedge accounting for our physical energy delivery activities because accrual accounting more closely aligns the timing of earnings recognition, cash flows, and the underlying business activities. We apply mark-to-market accounting for certain risk management and trading activities as follows:

- our competitive retail gas customer supply activities and, for new transactions closed since June 30, 2010, our fixed quantity competitive retail power 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,
- economic hedges of other contracts that require mark-to-market accounting treatment to ensure symmetrical accounting treatment,
- economic hedges of activities that require accrual accounting,
- interest rate swaps related to our debt if we do not elect hedge accounting, and
- trading activities.

As a result of making these judgments, the selection of accounting treatment for derivatives 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 (AOCI). 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
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 or when the forecasted transaction	Hedged margin recognized in earnings	Revenue or expense recognized in earnings when underlying physical commodity is sold or consumed

becomes probable of not
occurring

Valuation

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. 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

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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 could 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 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,
- 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, real estate, and unamortized energy contracts) to determine if they are impaired when certain conditions exist. 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,
- negative credit events of a counterparty,
- 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 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.

Unproved Gas Properties

We evaluate unproved property at least annually to determine if it is impaired. 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. The determination of whether to continue to develop the lease is based upon the economics (forward prices and the level of gas reserves) associated with extracting the estimated gas reserves, which necessarily involves the exercise of judgment.

Investments

We evaluate our equity method and cost method investments, including our partnerships that own power projects to determine whether or not they are impaired. The standard for determining whether an impairment must be recorded is whether the investment has experienced an "other than a temporary" decline in value.

The evaluation and measurement of investment impairments involves the same uncertainties as described above for long-lived assets that we own directly. 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, we would record our proportionate share of that impairment loss and would evaluate our investment for an other than temporary decline in value.

We continuously monitor issues that potentially could impact future profitability of our equity method investments that own coal, hydroelectric, fuel processing projects, as well as our equity investment in our nuclear joint venture. These issues include 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.

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 renewable energy projects could become impaired, and any losses recognized 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 do not amortize goodwill. We 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.

Significant Events

Pending Merger with Exelon Corporation

On April 28, 2011, we entered into an Agreement and Plan of Merger with Exelon Corporation (Exelon). At closing, each issued and outstanding share of common stock of Constellation Energy will be cancelled and converted into the right to receive 0.93 shares of common stock of Exelon, and Constellation Energy will become a wholly owned subsidiary of Exelon.

Prior to the completion of the merger, which is subject to various approvals, Constellation Energy will continue to operate as a separate company. The following discussion and analysis of our results of operations and financial condition relates solely to Constellation Energy and its subsidiaries.

We discuss this transaction and the costs incurred to date in more detail in *Note 2 to Consolidated Financial Statements*.

Acquisitions

Haynesville Shale Gas Property

In December 2011, we acquired natural gas working interests and net revenue interests in certain producing wells and certain proved developed wells and proved undeveloped locations in Louisiana for a total of approximately $58.2 million. We discuss this transaction in more detail in *Note 15 to Consolidated Financial Statements*.

ONEOK Energy Marketing Company

In February 2012, we acquired all of the outstanding stock of ONEOK Energy Marketing Company, a retail natural gas marketing company, for approximately $22.5 million, subject to a working capital adjustment. We discuss this transaction in more detail in *Note 15 to Consolidated Financial Statements*.

MXenergy Holdings Inc.

In July 2011, we acquired all of the outstanding stock of MXenergy Holdings Inc. (MXenergy), a retail energy marketer of natural gas and electricity to residential and commercial customers in competitive markets in the United States and Canada for approximately $218.7 million in cash. We discuss this transaction in more detail in *Note 15 to Consolidated Financial Statements*.

Star Electricity, Inc.

In May 2011, we acquired all of the outstanding stock of Star Electricity, Inc. (StarTex), a retail electric provider, for approximately $160.4 million in cash. We discuss this transaction in more detail in *Note 15 to Consolidated Financial Statements.*

Boston Generating

In January 2011, we completed the acquisition of Boston Generating's 2,950 MW fleet of generating plants for approximately $1.1 billion in cash. We discuss this transaction in more detail in *Note 15 to Consolidated Financial Statements.*

Divestitures

Upstream Gas Property

In December 2011, we sold all of our interests in a subsidiary that owned natural gas assets in the south Texas region for $93.0 million. We recognized a $23.0 million pre-tax gain. We discuss this transaction in *Note 2 to Consolidated Financial Statements*.

Constellation Energy Partners LLC

In August 2011, we sold a majority of our equity interests in Constellation Energy Partners LLC (CEP) to PostRock Energy Corporation (PostRock) for cash, shares of PostRock common stock and warrants to buy additional shares of PostRock common stock. In December 2011, we sold additional equity interests in CEP to PostRock for cash. We discuss these transactions in more detail in *Note 2 to Consolidated Financial Statements*.

Quail Run Energy Center

In June 2011, we terminated the agreement to sell our Quail Run Energy Center (Quail Run), a 550 MW natural gas plant in west Texas, to High Plains Diversified Energy Corporation. We had previously entered into the agreement to sell Quail Run in December 2010. We discuss this development in *Note 2 to Consolidated Financial Statements*.

Commodity Prices

During 2011, the energy markets were affected by large fluctuations in both forward and spot commodity prices. The changes in spot prices from January 1, 2011 through December 31, 2011 were as follows:

- power prices declined approximately 21%, and
- gas prices declined by approximately 32%.

These changes in commodity prices contributed to significant mark-to-market losses, resulted in impairment charges, and, therefore, materially impacted our results. We discuss these changes in the *Results of Operations* section.

Gains on Settlements with U.S. Department of Energy (DOE)

During 2011, we recognized the following pre-tax gains related to agreements with the DOE that settled lawsuits to recover damages for costs incurred through November 6, 2009 caused by the DOE's failure to comply with legal and contractual obligations to dispose of spent nuclear fuel at these nuclear plants:

- $39.4 million related to the Calvert Cliffs nuclear power plant, and
- $54.4 million related to the Ginna nuclear power plant.

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

Financings

BGE Issuance of Notes

In November 2011, BGE issued $300 million of 3.50% Notes due November 15, 2021. We discuss this financing transaction in more detail in *Note 9 to Consolidated Financial Statements.*

Secured Solar Credit Lending Agreement

In July 2011, a subsidiary of Constellation Energy entered into a three year senior secured credit facility associated with certain solar projects that we own. The amount committed under the facility is $150 million. We discuss this lending agreement in more detail in *Note 9 to Consolidated Financial Statements*.

Amended Reserve-Based Facility for Upstream Gas Operations

In July 2011, we amended and extended our existing reserve based lending facility that supports our upstream gas operations. The borrowing base committed under the facility was increased to $150 million. We discuss this agreement in more detail in *Note 9 to Consolidated Financial Statements*.

Sacramento Solar Project Facility

In July 2011, a subsidiary of Constellation Energy entered into a $40.7 million nonrecourse project financing to fund construction of our 30MW solar facility in Sacramento, California. The construction borrowings will convert into a 19-year variable rate note upon commercial operation of the facility. We discuss this financing in more detail in *Note 9 to Consolidated Financial Statements*.

Revolving Promissory Note with CENG

In May 2011, CENG issued an unsecured revolving promissory note to borrow up to an aggregate principal amount of $62.5 million from a subsidiary of Constellation Energy. We discuss this related party financing in *Note 16 to Consolidated Financial Statements*.

Third Quarter 2011 Texas Weather Event

In the third quarter of 2011, the Texas region incurred extreme high temperatures for a prolonged period of time. This heat wave was compounded by fossil generator outages and a lack of wind plant availability throughout the region, which led to price spikes well above historical averages for replacement power that we had to purchase. This negatively affected our NewEnergy operating results by approximately $33 million after-tax. We discuss the impact of this development on our overall results in the *NewEnergy operating results* section.

Hurricane Irene

In August 2011, Hurricane Irene caused extensive damage to BGE's electric distribution system and created power outages that lasted several days. BGE incurred total costs currently estimated to be $79.7 million, which includes capital costs of $29.6 million and maintenance expenses of $50.1 million pre-tax, or $29.9 million after-tax, in 2011 to repair its distribution system and restore service to customers. The maintenance expenses included $41.1 million pre-tax, or $24.6 million after-tax, of estimated incremental expenses. We discuss the impact of Hurricane Irene on our *Regulated Electric Business operating results* section.

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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 (expense) income, fixed charges, and income taxes are discussed in the aggregate for all segments in the *Consolidated Nonoperating Income and Expenses* section.

As discussed in *Item 1 Business Overview* section and in the *Strategy* and *Significant Events* sections, Constellation Energy's 2011, 2010 and 2009 operating results were materially impacted by a number of significant events, transactions, and changes in our strategic direction. The impact of these items has affected the comparability of our 2011, 2010 and 2009 results to prior periods and will alter Constellation Energy's operating results in the future. In this section, we highlight the 2011, 2010 and 2009 impacts of these items.

Overview

Results

	2011	2010	2009
		(In millions, after-tax)	
Net (Loss) Income:			
Generation	**$ (441.1)**	$ (1,255.3)	$ 4,766.7
NewEnergy	**2.8**	176.2	(348.2)
Regulated electric	**93.6**	110.0	79.1
Regulated gas	**42.1**	37.6	25.5
Other nonregulated	**(4.2)**	(0.3)	(19.7)
Net (Loss) Income	**$ (306.8)**	$ (931.8)	$ 4,503.4
Net (Loss) Income attributable to common stock	**$ (340.3)**	$ (982.6)	$ 4,443.4
Change from prior year	**$ 642.3**	$ (5,426.0)	

Our total net loss attributable to common stock for 2011 decreased compared to 2010 by $642.3 million, or $3.20 per share, mostly because of the following:

	Increase/(Decrease) 2011 vs. 2010
	(In millions, after-tax)
Generation gross margin	$ 81
Increases in Generation non-gross margin expenses related to:	
Acquisition of Boston Generating fleet of generating assets in January 2011	(81)
NewEnergy gross margin	(116)
NewEnergy hedge ineffectiveness	(24)
NewEnergy third quarter 2011 Texas region weather event	(33)
NewEnergy gain on divestitures	34
NewEnergy contract assignments / origination	25
Regulated businesses	27
Other nonregulated businesses	(9)
Total change in *Other Items Included in Operations* per table below	797
All other changes	(59)
Total Change	$ 642

Our total net (loss) income attributable to common stock for 2010 decreased compared to 2009 by $5.4 billion, or $27.09 per share, mostly because of the following:

		Increase/(Decrease) 2010 vs. 2009
		(In millions, after-tax)
Generation gross margin, primarily due to the deconsolidation of CENG	$	(682)
Lower Generation operating expenses, primarily labor and benefit costs due to the deconsolidation of CENG		390
Lower Generation accretion expense of asset retirement obligations due to deconsolidation of CENG		37
Lower Generation taxes other than income taxes due to deconsolidation of CENG		27
Lower Generation depreciation and amortization due to deconsolidation of CENG		28
NewEnergy gross margin		78
NewEnergy hedge ineffectiveness		(55)
Loss on NewEnergy international coal contract assignments		(25)
Regulated businesses		(21)
Other nonregulated businesses		5
Total change in *Other Items Included in Operations* per table below		(5,375)
All other changes		167
Total Change	$	(5,426)

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Other Items Included in Operations (after-tax):

	2011	2010	2009
	(In millions, after-tax)		
Impairment losses and other costs	**$ (530.2)**	$ (1,487.1)	$ (96.2)
Impact of power purchase agreement with CENG (1)	**(118.5)**	(113.3)	
Amortization of basis difference in CENG	**(90.5)**	(117.5)	(17.8)
Hurricane Irene incremental storm expenses	**(24.6)**		
Merger costs	**(70.9)**		(13.8)
Gain on settlements with DOE	**57.3**		
Transaction fees for Boston Generating acquisition	**(9.9)**		
Gain on Comprehensive Agreement with EDF		121.3	
International coal contract dispute settlement		35.4	
Loss on early retirement of 2012 Notes		(30.9)	
Gain on sale of interest in Mammoth Lakes geothermal generating facility		24.7	
Credit facility amendment/termination fees	**(5.8)**	(13.6)	(37.7)
Deferred income tax expense relating to federal subsidies for providing post-employment prescription drug benefits		(8.8)	
Gain on sale of 49.99% interest in CENG			4,456.1
International commodities operation and gas trading operation (2)			(371.9)
BGE residential customer rate credit			(67.1)
Impairment of nuclear decommissioning trust assets			(46.8)
Loss on redemption of Zero Coupon Senior Notes			(10.0)
Workforce reduction costs			(9.3)
Total Other Items	**$ (793.1)**	$ (1,589.8)	$ 3,785.5
Change from prior year	**$ 796.7**	$ (5,375.3)	

(1) *The net impact to the Company of the power purchase agreement with CENG was $200.4 million pre-tax for 2011 and $185.6 million pre-tax for 2010. This amount represents the amortization of our $0.8 billion "Unamortized energy contract asset" less our 50.01% equity in CENG's amortization of its $0.8 billion "Unamortized energy contract liability."*

(2) *These amounts include the net losses on the sales of the international commodities operation, gas trading operation, certain other trading operations, and a uranium market participant, the reclassification of losses on previously designated cash-flow hedges from Accumulated Other Comprehensive Loss because the forecasted transactions were probable of not occurring, and earnings that are no longer part of our core business. The impairment losses and other costs and workforce reduction costs line items for 2009 also include amounts related to the operations we divested.*

Generation Business

Background

Our Generation business is discussed in detail in *Item 1. Business Operating Segments* section.

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

During 2011, power prices continued to decline, reflecting economic conditions and projected increases in natural gas supplies. However, prices for coal have not declined to the same extent as power prices. The relationship between power and fuel prices directly affects the earnings of our Generation business. Although our NewEnergy business hedges portions of our future power sales and fuel purchases, the amounts we have hedged are higher for the near term and decline over time. We have already locked in prices for our expected generation output for 2012. However, consistent with our hedging approach, we have only hedged a portion of the expected output for 2013, and those hedges are at lower prices. If the current power and fuel price environment continues, we anticipate that our Generation business will have lower earnings in future years, especially in 2012.

Additionally, we evaluated our generating plants and our investments in electric generation facilities for impairment as a result of power price declines in 2011. We recorded an impairment charge in 2011 for our investments in electric generation facilities and our investment in CENG, but none of our wholly owned generating plants were impaired. However, further decreases in power prices could result in estimated future cash flows declining below the carrying value of our plants, which would require us to record an impairment charge on our generating plants. We discuss our impairment charges in *Note 2 to Consolidated Financial Statements*.

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Results

	2011	2010	2009
		(In millions)	
Revenues	**$ 2,717.7**	$ 2,244.3	$ 2,774.2
Fuel and purchased energy expenses	**(1,766.8)**	(1,444.8)	(692.0)
Gross margin	**950.9**	799.5	2,082.2
Operating expenses	**(468.7)**	(379.7)	(1,008.4)
Impairment losses and other costs	**(891.0)**	(2,476.7)	
Merger costs	**(61.2)**		(101.8)
Depreciation, depletion, accretion, and amortization	**(187.4)**	(137.7)	(238.9)
Taxes other than income taxes	**(45.1)**	(23.6)	(67.4)
Equity investment earnings (losses):			
CENG	**(4.3)**	23.6	4.3
UNE		(16.8)	(24.7)
Other	**24.1**	18.2	20.6
Gain on settlement with DOE	**93.8**		
Net gain on divestitures		242.9	7,445.6
(Loss) Income from Operations	**$ (588.9)**	$ (1,950.3)	$ 8,111.5
Net (Loss) Income	**$ (441.1)**	$ (1,255.3)	$ 4,766.7
Net (Loss) Income attributable to common stock	**$ (441.1)**	$ (1,255.3)	$ 4,766.7
Change from prior year	**$ 814.2**	$ (6,022.0)	
Other Items Included in Operations (after-tax):			
Impairment losses and other costs	**$ (530.2)**	$ (1,487.1)	$
Impact of power purchase agreement with CENG (1)	**(118.5)**	(113.3)	
Amortization of basis difference in CENG	**(90.5)**	(117.5)	(17.8)
Gain on settlements with DOE	**57.3**		
Merger costs	**(37.0)**		(9.7)
Transaction fees for Boston Generating acquisition	**(9.9)**		
Gain on Comprehensive Agreement with EDF		121.3	
Loss on early retirement of 2012 Notes		(30.9)	
Gain on sale of Mammoth Lakes geothermal generating facility		24.7	
Credit facility amendment/termination fees		(9.0)	(13.7)
Deferred income tax expense relating to federal subsidies for providing post-employment prescription drug benefits		(0.8)	
Gain on sale of 49.99% interest in CENG			4.456.1
Impairment of nuclear decommissioning trust assets			(46.8)
Loss on redemption of Zero Coupon Senior Notes			(10.0)
Total Other Items	**$ (728.8)**	$ (1,612.6)	$ 4,358.1
Change from prior year	**$ 883.8**	$ (5,970.7)	

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.

(1) *The net impact to the Company of the power purchase agreement with CENG was $200.4 million pre-tax for 2011 and $185.6 million pre-tax for 2010. This amount represents the amortization of our $0.8 billion "Unamortized energy contract asset" less our 50.01% equity in CENG's amortization of its $0.8 billion "Unamortized energy contract liability."*

Effects of 2009 Transaction with EDF on Statement of Income (Loss)

Prior to November 6, 2009, CENG was a 100% owned subsidiary, and we consolidated its financial results within our Consolidated Statements of Income (Loss). On November 6, 2009, we completed the sale of a 49.99% membership interest in CENG to EDF, and we deconsolidated CENG. Accordingly, beginning November 6, 2009, we ceased recording CENG's financial results and began to record equity investment earnings from CENG as well as the effect of our PPA and other transactions with CENG. This change in accounting treatment affected the comparability of Generation's results between 2010 and 2009. We discuss our transaction with EDF in more detail in *Note 2 to Consolidated Financial Statements.*

Revenues

Our Generation revenues increased $473.4 million in 2011 compared to 2010 and decreased $529.9 million in 2010 compared to 2009 primarily due to the following:

	2011 vs. 2010	2010 vs. 2009
	(In millions)	
Decrease in volume of output primarily due to the deconsolidation of CENG nuclear generating assets	**$**	$ (690)
Increase in volume of output primarily due to the acquisition of the Boston Generating fleet of generating assets in January 2011, additional volume due to the beginning of commercial dispatch of the Hillabee Energy Center and the acquisition of the Texas combined cycle generation facilities in 2010	**648**	198
Increase (decrease) in volume of output due to reduced (higher) impact of outages at our fossil plants	**38**	(127)
(Decrease) increase in contracted power prices	**(227)**	116
All other	**14**	(27)
Total increase (decrease) in Generation revenues	**$ 473**	$ (530)

Fuel and Purchased Energy Expenses

Our Generation fuel and purchased energy expenses increased $322.0 million in 2011 compared to 2010 and increased $752.8 million in 2010 compared to 2009 primarily due to the following:

	2011 vs. 2010	2010 vs. 2009
	(In millions)	
Increase in purchased energy costs due to power purchase agreement with CENG compared with nuclear fuel costs	**$**	$ 741
Increase in volume of gas consumed due to the acquisition of the Boston Generating fleet of generating assets in January 2011	**218**	
Increase (decrease) due to reduced (higher) impact of outages at our fossil plants	**2**	(87)
Increase in fuel costs primarily related to higher contract prices to operate our generating assets	**56**	59
All other	**46**	40
Total increase in Generation fuel and purchased energy expenses	**$ 322**	$ 753

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Operating Expenses

Our Generation business operating expenses increased $89.0 million during 2011 as compared to 2010 primarily due to the costs associated with the acquisition of the Boston Generating fleet of generating assets in January 2011.

Our Generation business operating expenses decreased $628.7 million during 2010 as compared to 2009 due to lower labor and benefit costs of $499.9 million and lower non-labor operating expenses of $128.8 million, the majority of which results from the absence of costs in 2010 due to the deconsolidation of CENG.

Impairment Losses and Other Costs

We discuss our impairment charges in more detail in *Note 2 to Consolidated Financial Statements*.

Merger Costs

We discuss costs related to the proposed merger with Exelon in more detail in *Note 2 to Consolidated Financial Statements*.

Depreciation, Depletion, Accretion, and Amortization Expense

Our Generation business incurred higher depreciation, depletion, accretion, and amortization expenses of $49.7 million during 2011 compared to 2010 primarily due to additional depreciation of:

- $33.8 million on the Boston Generating facilities acquired in January 2011,
- $5.2 million related to a sub-bituminous safety system and coal conveyor that was placed in service in 2011 at one of our coal generating facilities, and
- $6.7 million related to the June 2010 commencement of operations at our Hillabee Energy Center.

Our Generation business incurred lower depreciation, depletion, accretion, and amortization expenses of $101.2 million during 2010 compared to 2009 due to a decrease of $94.0 million in depreciation on the nuclear generating facilities and a decrease of $60.5 million in accretion on asset retirement obligations, both resulting from the deconsolidation of CENG on November 6, 2009. These decreases were partially offset by an increase of $53.4 million in depreciation on our other generating facilities primarily related to the installation of emission control equipment at our Brandon Shores coal-fired generating plant that went into service in the fourth quarter of 2009, the Texas combined cycle generation facilities we acquired in 2010, and the Hillabee Energy Center, which began commercial dispatch in 2010.

Taxes Other Than Income Taxes

Our Generation business incurred higher taxes other than income taxes of $21.5 million in 2011 compared to 2010, primarily due to an increase in property taxes related to generating facilities acquired in Texas in 2010 and Massachusetts in 2011.

Our Generation business incurred lower taxes other than income taxes of $43.8 million in 2010 compared to 2009, primarily due to lower property taxes as a result of the deconsolidation of CENG on November 6, 2009.

Equity Investment Earnings (Losses)

During 2011, our equity investment earnings decreased $5.2 million as compared to 2010, primarily due to lower CENG operating results of $27.9 million, partially offset by the absence of $16.8 million of losses on our investment in UNE, which was sold in 2010.

During 2010, our equity investment earnings increased $24.8 million as compared to 2009, primarily due to $19.3 million of higher earnings from our investment in CENG, $7.9 million of lower losses from our investment in UNE, which was sold in 2010, partially offset by $2.4 million of lower earnings on investments in power projects.

In December 2011, CENG's wholly owned subsidiary, Nine Mile Point, entered into a three year agreement with the applicable tax jurisdictions in New York State with respect to property tax payments on the Nine Mile Point nuclear generating facility. The agreement will not materially increase future property tax expenses for CENG for the term of the agreement and, as a result, will not materially impact our equity investment earnings in CENG based on our 50.01% ownership interest. The agreement also will result in settlement and discontinuance of all pending property tax assessment litigation proceedings between Nine Mile Point and the tax jurisdictions.

Gain on Settlements with DOE

During 2011, we recognized $93.8 million in pre-tax gains related to agreements with the DOE that settled the lawsuits that sought to recover damages caused by the DOE's failure to comply with legal and contractual obligations to dispose of spent nuclear fuel at the Calvert Cliffs nuclear power plant and the Ginna nuclear power plant. The lawsuit related to the Nine Mile Point nuclear power plant remains outstanding. We discuss these settlements in more detail in *Note 2 to Consolidated Financial Statements.*

NewEnergy Business

Background

Our NewEnergy business is a competitive provider of energy solutions for various customers. We discuss the impact of competition on our NewEnergy business in *Item 1. Business Competition* section.

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

We record NewEnergy revenues and expenses in our financial results in different periods depending upon the appropriate accounting treatment that represents the economics of the underlying transactions in our business. We discuss our revenue recognition policies in the *Critical Accounting Policies* section and *Note 1 to Consolidated Financial Statements*.

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Results

	2011	2010	2009
		(In millions)	
Revenues	**$ 10,120.2**	$ 10,121.4	$ 11,509.2
Fuel and purchased energy expenses	**(9,071.6)**	(8,877.6)	(10,430.0)
Gross margin	**1,048.6**	1,243.8	1,079.2
Operating expenses	**(843.1)**	(758.7)	(763.6)
Merger costs	**(26.4)**		(44.0)
Impairment losses and other costs		(0.1)	(98.1)
Workforce reduction costs			(12.6)
Depreciation, depletion, accretion, and amortization	**(89.4)**	(83.7)	(82.7)
Taxes other than income taxes	**(70.2)**	(52.8)	(41.2)
Equity investment (losses) earnings			(6.3)
Net gain (loss) on divestitures	**57.3**	2.5	(468.8)
Income (Loss) from Operations	**$ 76.8**	$ 351.0	$ (438.1)
Net Income (Loss)	**$ 2.8**	$ 176.2	$ (348.2)
Net (Loss) Income attributable to common stock	**$ (17.5)**	$ 138.6	$ (402.3)
Change from prior year	**$ (156.1)**	$ 540.9	
Other Items Included in Operations (after-tax):			
Merger costs	**$ (16.1)**	$	$ (4.1)
International coal contract dispute settlement		35.4	
Credit facility amendment/termination fees	**(5.8)**	(4.6)	(24.0)
Deferred income tax expense relating to federal subsidies for providing post-employment prescription drug benefits		(0.1)	
International commodities operation and gas trading operation (1)			(371.9)
Impairment losses and other costs			(84.7)
Workforce reduction costs			(9.3)
Total Other Items	**$ (21.9)**	$ 30.7	$ (494.0)
Change from prior year	**$ (52.6)**	$ 524.7	

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.

(1) *Amount includes the net losses on the sales of the international commodities operation, gas trading operation, certain other trading operations, and a uranium market participant, the reclassification of losses on previously designated cash-flow hedges from Accumulated Other Comprehensive Loss because the forecasted transactions were probable of not occurring, and earnings that are no longer part of our core business. The impairment losses and other costs and workforce reduction costs line items for 2009 also include amounts related to the operations we divested.*

Revenues

Our NewEnergy revenues were essentially unchanged in 2011 compared to 2010 and decreased $1,387.8 million in 2010 compared to 2009 primarily due to the following:

	2011 vs. 2010	2010 vs. 2009
	(In millions)	

Realization of higher (lower) wholesale load sales	**$ 463**	$ (917)
Decrease in volume and contract prices related to our domestic coal operation	**(24)**	(508)
Realization of (lower) higher retail power load sales	**(118)**	398
Decrease due to the assignment of international coal and freight contracts, which we divested throughout 2009 and 2010	**(175)**	(321)
Gain on sale of in-the-money wholesale load contract in the second quarter of 2009		(106)
Change in volumes at our retail gas and wholesale gas operation	**(92)**	(77)
(Decrease) increase in wholesale mark-to-market revenues due to changes in power and gas prices	**(274)**	77
Increase due to acquisitions of StarTex and MXenergy	**317**	
All other	**(98)**	66
Total decrease in NewEnergy revenues	**$ (1)**	$ (1,388)

Fuel and Purchased Energy Expenses

Our NewEnergy fuel and purchased energy expenses increased $194.0 million in 2011 compared to 2010 and decreased $1,552.4 million in 2010 compared to 2009 primarily due to the following:

	2011 vs. 2010	**2010 vs. 2009**
	(In millions)	
Realization of fuel and purchased energy from wholesale power purchases	**$ 306**	$ (641)
Decrease due to the assignment of international coal and freight contracts, which we divested throughout 2009 and 2010	**(77)**	(540)
Decrease in volume and contract prices related to our domestic coal operation	**(23)**	(498)
(Decrease) increase in (prices) volumes of retail power load purchases	**(154)**	217
Change in volumes at our retail gas and wholesale gas operation	**(54)**	(83)
Increase due to acquisitions of StarTex and MXenergy	**236**	
All other	**(40)**	(7)
Total increase (decrease) in NewEnergy fuel and purchased energy expenses	**$ 194**	$ (1,552)

From time to time, we may terminate or restructure contracts to lower our exposure to various risks under these contracts. During 2011, we terminated three contracts that increased gross margin by $26.9 million:

$12.7 million related to the partial termination of a firm gas transportation capacity contract in order to mitigate risk on the last two years of the contract,

$8.2 million related to the termination of certain in-the-money load-serving contracts in an effort to

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- mitigate variable load risk and reduce the impact of future commodity price changes on future gross margin, and

- $6.0 million related to an energy purchase contract that was terminated in order to eliminate the unit contingent risk associated with the energy purchase.

The decrease in gross margin for 2011 compared to 2010 included a less favorable price environment in the Texas region due to two discrete events. In the first quarter of 2011, the Texas region experienced sudden, extreme drops in temperature, coupled with high winds. This weather event caused generation to go off-line and forced generators and load serving entities, like us, to purchase replacement power at significantly increased spot prices. Additionally, in the third quarter of 2011, the Texas region incurred extreme high temperatures for a prolonged period of time. This heat wave was compounded by fossil generator outages and a lack of wind plant availability throughout the region which led to price spikes well above historical averages for replacement power we had to purchase.

Mark-to-Market

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

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

During 2009 and 2010, we focused our activities on reducing capital requirements, reducing long-term economic risk, and reducing short- and interim-term liquidity requirements. These actions impacted the results of the NewEnergy business, particularly the size of and potential for changes in fair value of activities subject to mark-to-market accounting in 2011 and will impact the results in future years.

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

Origination gains arise primarily from contracts that our NewEnergy business structures to meet the risk management needs of our customers or relate to our trading activities. Transactions that result in origination gains may be unique and provide the potential for individually significant revenues and gains from a single transaction. We recorded a $14.8 million pre-tax origination gain related to one transaction in 2011. In 2011, our NewEnergy business amended a nonderivative capacity sales contract such that the amended contract met the definition of a derivative subject to mark-to-market accounting. Simultaneous with the amending of the nonderivative contract, we executed at current market value a new derivative capacity purchase contract subject to mark-to-market accounting. The combination of these transactions resulted in substantially all of the origination gains presented for 2011 as well as mitigated our risk exposure under the amended contracts.

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

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

Mark-to-market results were as follows:

	2011	2010	2009
		(In millions)	
Unrealized mark-to-market results			
Origination gains	**$ 14.8**	$	$
Risk management and trading mark-to-market			
Unrealized changes in fair value	**(279.1)**	9.6	(212.3)
Changes in valuation techniques			
Reclassification of settled contracts to realized	**(78.4)**	(139.0)	(265.4)
Total risk management and trading mark-to-market	**(357.5)**	(129.4)	(477.7)
Total unrealized mark-to-market (1)	**(342.7)**	(129.4)	(477.7)
Realized mark-to-market	**78.4**	139.0	265.4
Total mark-to-market results (2)	**$ (264.3)**	$ 9.6	$ (212.3)

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

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

Total mark-to-market results decreased $273.9 million during the year ended December 31, 2011 compared to the same period of 2010 due to unrealized changes in fair value primarily due to:

$211 million of lower results on open positions in our power and transmission management activities within the NEPOOL and PJM regions due to a less favorable price environment,

$34 million related to unrealized positions in our retail power and gas operations,

$19 million related to economic hedges of our upstream natural gas operations due to a less favorable price environment, and

$10 million related to our domestic coal portfolio due to a less favorable price environment.

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Total mark-to-market results increased $221.9 million during the year ended December 31, 2010 compared to the same period of 2009 due to unrealized changes in fair value primarily due to:

- $197 million of higher results on open positions primarily due to the absence of losses in our power and transmission risk management activities in the PJM, Midwest, New York, and West regions as a result of a favorable price environment in 2010 and completion of our activities to reduce risk and improve liquidity,
- $31 million of higher gains on open positions primarily due to the absence of losses in 2010 resulting from a more favorable price environment related to our retail power and gas businesses,
- $18 million of higher results in our domestic coal portfolio primarily due to a more favorable price movement, and
- $16 million of higher results on open positions due to a more favorable price environment related to economic hedges of our upstream gas operations and risk management activities.

These increases were partially offset by the absence of $40 million in results from our international coal and freight operations, which we divested in 2009.

Derivative Assets and Liabilities

Derivative assets and liabilities consisted of the following:

At December 31,	**2011**	2010
	(In millions)	
Current assets	**$ 357.9**	$ 534.4
Noncurrent assets	**259.3**	258.9
Total assets	**617.2**	793.3
Current liabilities	**779.5**	622.3
Noncurrent liabilities	**268.4**	353.0
Total liabilities	**1,047.9**	975.3
Net derivative position	**$ (430.7)**	$ (182.0)
Composition of net derivative exposure:		
Hedges	**$ (224.2)**	$ (504.5)
Mark-to-market	**(63.1)**	350.3
Net cash collateral included in derivative balances	**(143.4)**	(27.8)
Net derivative position	**$ (430.7)**	$ (182.0)

Derivative balances above include noncurrent assets related to our Generation business of $48.9 million and $35.7 million at December 31, 2011 and December 31, 2010, respectively. Derivative balances related to our Generation business consist of interest rate contracts accounted for as fair value hedges.

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 in *Note 13 to Consolidated Financial Statements.*

The decrease of $280.3 million in our net derivative liability subject to hedge accounting since December 31, 2010 was due to $535.3 million of realization of out-of-the-money cash-flow hedges at the time the forecasted transaction occurred, partially offset by $255.0 million of increases on our out-of-the-money cash-flow hedge positions primarily related to decreases in power, natural gas, and coal prices during 2011.

The increase in cash collateral held primarily relates to transactions with one counterparty, and, as a result of the decrease in power prices, our positions are more in-the-money, requiring the counterparty to provide us with more cash collateral.

The following are the primary sources of the change in our net derivative asset (liability) subject to mark-to-market accounting during 2011 and 2010:

	2011		**2010**	
		(In millions)		
Fair value beginning of year		**$ 350.3**		$ 524.3
Changes in fair value recorded in earnings				
Origination gains	**$ 14.8**		$	
Unrealized changes in fair value	**(279.1)**		9.6	
Changes in valuation techniques				
Reclassification of settled contracts to realized	**(78.4)**		(139.0)	
Total changes in fair value		**(342.7)**		(129.4)
Changes in value of exchange-listed futures and options		**(215.8)**		(197.1)
Net change in premiums on options		**(40.2)**		17.7
Contracts acquired		**(7.4)**		5.4
Dedesignated contracts and other changes in fair value		**192.7**		129.4
Fair value at end of year		**$ (63.1)**		$ 350.3

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

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settled during the period and recorded as realized revenues.

The net derivative asset also changed due to the following items:

Changes in value of exchange-listed futures and options are recorded in "Accounts receivable" rather than "Derivative assets" in our Consolidated Balance Sheets because these amounts are settled through our margin account with a third party broker.

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

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

Dedesignated contracts and other changes in fair value primarily represent realization of the value of derivative contracts previously transferred from cash-flow hedges to mark-to-market or from mark-to-market to cash-flow hedges.

The settlement terms of the portion of our net derivative asset subject to mark-to-market accounting and sources of fair value based on the fair value hierarchy are as follows as of December 31, 2011:

	Settlement Term							
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**Thereafter**	**Fair Value**
	(In millions)							
Level 1	$ (1.7)	$	$	$	$	$	$	$ (1.7)
Level 2	(33.3)	(19.1)	(7.6)	14.5	16.1	2.1	(0.2)	(27.5)
Level 3	50.4	(34.7)	(11.6)	(9.0)	(11.2)	(8.6)	(9.2)	(33.9)
Total net derivative asset (liability) subject to mark-to-market accounting	$ 15.4	$ (53.8)	$ (19.2)	$ 5.5	$ 4.9	$ (6.5)	$ (9.4)	$ (63.1)

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

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

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

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

Operating Expenses

Our NewEnergy business operating expenses increased $84.4 million during 2011 as compared to 2010 due to growth in this business segment: primarily $31.3 million and $35.8 million, respectively, due to the acquisitions of StarTex (May 2011) and MXenergy (July 2011), and $11.5 million due to an increase in marketing and advertising related to our residential electricity program.

Merger Costs

We discuss costs related to the proposed merger with Exelon in more detail in *Note 2 to Consolidated Financial Statements*.

Taxes Other Than Income Taxes

Our NewEnergy business incurred higher taxes other than income taxes of $17.4 million in 2011 compared to 2010, primarily due to higher gross receipts taxes related to an increase in retail revenues, primarily in Pennsylvania.

Our NewEnergy business incurred higher taxes other than income taxes of $11.6 million in 2010 compared to 2009, primarily due to higher gross receipts taxes related to an increase in retail revenues, primarily in Pennsylvania.

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Net Gain (Loss) on Divestitures

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

	2011	2010	2009
Upstream working interests	**$ 23.6**	$	$
Interests in CEP	**33.7**		
Majority of our international commodities operation			(334.5)
Houston-based gas trading operation			(102.5)
Uranium market participant			(27.2)
Portfolio of contracts in our retail gas operations		2.0	
Other		0.5	(4.6)
Total net gain (loss) on divestiture	**$ 57.3**	$ 2.5	$ (468.8)

We discuss these divestitures 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

	2011	2010	2009
		(In millions)	
Revenues	**$ 2,321.4**	$ 2,752.3	$ 2,820.7
Electricity purchased for resale expenses	**(1,184.7)**	(1,680.9)	(1,840.9)
Operations and maintenance expenses	**(505.8)**	(449.3)	(399.0)
Merger costs	**(22.6)**		
Depreciation and amortization	**(226.5)**	(205.2)	(218.1)
Taxes other than income taxes	**(154.9)**	(149.1)	(142.9)
Income from Operations	**$ 226.9**	$ 267.8	$ 219.8
Net Income	**$ 93.6**	$ 110.0	$ 79.1
Net Income attributable to common stock	**$ 83.8**	$ 99.8	$ 68.9
Other Items Included in Operations (after-tax):			
Hurricane Irene incremental storm expenses	**$ (24.6)**	$	$
Merger costs (1)	**(13.3)**		
Deferred income tax expense relating to federal subsidies for providing post-employment prescription drug benefits		(3.1)	
Residential customer rate credit			(56.7)
Total Other Items	**$ (37.9)**	$ (3.1)	$ (56.7)

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.

(1)
BGE will not seek recovery of these costs in rates.

Net income attributable to common stock from the regulated electric business decreased $16.0 million in 2011 compared to 2010, primarily due to an increase in incremental restoration expenses related to Hurricane Irene of $24.6 million after-tax and a $12.7 million after-tax increase in depreciation and amortization. These increases in expenses were partially offset by an increase in base rate distribution revenues of

$18.0 million after-tax resulting from the December 2010 Maryland PSC rate order.

Net income attributable to common stock from the regulated electric business increased $30.9 million in 2010 compared to 2009, mostly due to the absence in 2010 of $56.7 million after-tax in credits provided to customers in 2009 and a $7.7 million after-tax decrease in depreciation and amortization, partially offset by a $30.3 million after-tax increase in operations and maintenance expenses.

Electric Revenues

The changes in electric revenues in 2011 and 2010 compared to the respective prior year were caused by:

	2011 vs. 2010	2010 vs. 2009
	(In millions)	
Distribution volumes	**$ (3.5)**	$ 32.7
Base rates	**27.7**	3.3
Residential customer rate credit		95.0
Smart Energy Savers Program® surcharges	**12.1**	(22.0)
Revenue decoupling	**16.5**	(30.9)
Standard offer service	**(502.5)**	(154.2)
Rate stabilization recovery	**(7.1)**	2.5
Financing credits	**(2.7)**	0.4
Senate Bill 1 credits	**1.0**	(12.9)
Total change in electric revenues from electric system sales	**(458.5)**	(86.1)
Other	**27.6**	17.7
Total change in electric revenues	**$ (430.9)**	$ (68.4)

<u>*Distribution Volumes*</u>

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 2011 and 2010 compared to the respective prior year were:

	2011	2010
Residential	**(9.3)%**	7.6%
Commercial	**1.4**	3.5
Industrial	**(0.4)**	(8.0)

In 2011, we distributed less electricity to residential customers due to milder weather, partially offset by increased usage per customer and an increased number of customers. We distributed more electricity to commercial customers due to increased usage per customer and an increased number of customers, partially offset by milder weather. We distributed less electricity to industrial customers primarily due to a decreased usage per customer.

In 2010, we distributed more electricity to residential and commercial customers due to warmer summer and colder fourth quarter weather and an increased number of customers. We distributed less electricity to industrial customers primarily due to decreased usage per customer.

Base Rates

On December 6, 2010, the Maryland PSC issued an abbreviated order authorizing BGE to increase electric distribution rates by $31.0 million for service rendered on or after December 4, 2010. This increase was based upon an 8.06% rate of return with a 9.86% return on equity and a 52% equity ratio. We discuss BGE's electric base rates in the *Regulation Maryland Base Rates* section.

Residential Customer Rate Credit

On October 30, 2009, the Maryland PSC issued an order approving Constellation Energy's transaction with EDF. Among other things, the order required Constellation Energy to fund a one-time distribution rate credit for BGE residential customers before the end of March 2010 totaling $110.5 million, or approximately $100 per customer, for which BGE recorded a liability in November 2009. In December 2009, BGE filed a tariff with the Maryland PSC stating BGE would give residential customers a rate credit of exactly $100 per customer. As a result, BGE accrued an additional $1.9 million for a total fourth quarter 2009 accrual of $112.4 million. The portion of this total credit allocated to residential electric customers was $95.0 million pre-tax. This credit was accrued in the fourth quarter of 2009 and applied to BGE residential electric customer bills in the first quarter of 2010.

Smart Energy Savers Program® Surcharge

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

Revenues increased in 2011 compared to 2010, primarily due to an increase in the customer surcharge rates in 2011.

Revenues declined in 2010 compared to 2009, primarily due to an increase in customer involvement in our programs. This increased participation increased customer credits and, therefore, decreased revenues.

Revenue Decoupling

The Maryland PSC has allowed us to record a monthly adjustment to our electric distribution revenues from residential and small commercial customers since 2008 and for the majority of our large commercial and industrial customers since February 2009 to eliminate the effect of abnormal weather and usage patterns per customer on our electric distribution volumes, thereby recovering a specified dollar amount of distribution revenues per customer, by customer class, regardless of changes in consumption levels. This means BGE recognizes revenues at Maryland PSC-approved levels per customer, regardless of what actual distribution volumes were for a billing period. Therefore, while these revenues are affected by customer growth, they will not be affected by actual weather (except as discussed below with regard to major storms) or usage conditions. We then bill or credit impacted customers in subsequent months for the difference between approved revenue levels under revenue decoupling and actual customer billings.

In January 2012, the Maryland PSC issued an order prospectively prohibiting Maryland electric utilities with a revenue decoupling mechanism from collecting a certain portion of decoupling revenue during major storm events if customer service is not restored within a specified period of time. We do not expect the impact of this prohibition to have a material effect on our, or BGE's, financial results.

Standard Offer Service

BGE provides standard offer service for customers that do not select an alternative supplier.

Standard offer service revenues decreased in 2011 compared to 2010 mostly due to a decrease in standard offer service volumes of 20% and a decrease in standard offer service rates of 15%. The volume decrease is primarily due to an increase in customers using competitive suppliers, while the decrease in service rates was due to the decreased cost of purchased electricity for the period.

Standard offer service revenues decreased in 2010 compared to 2009 mostly due to lower standard offer service rates and lower standard offer service volumes.

Rate Stabilization Recovery

In late June 2007, BGE began recovering amounts deferred during the first rate deferral period that began in July 2006 and ended on May 31, 2007. The recovery of the first rate stabilization plan is occurring over a ten year period. In April 2008, BGE began recovering amounts deferred during the second rate deferral period that began in June 2007 and ended on December 31, 2007. The recovery of the second rate deferral occurred over a 21-month period that began April 1, 2008 and ended on December 31, 2009.

Rate stabilization recovery revenue decreased during 2011 compared to 2010 primarily due to a decrease in volumes, partially offset by increased recovery rates charged to customers.

Financing Credits

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

Senate Bill 1 Credits

As a result of Senate Bill 1, beginning January 1, 2007, we were required to provide to residential electric customers a credit equal to the amount collected from all BGE electric customers for the decommissioning of 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 a 2008 Maryland settlement agreement, BGE was allowed to resume collection of the residential return portion of the administrative charge from June 1, 2008 through May 31, 2010 without having to rebate it to residential customers.

The decrease in revenues during 2010 compared to 2009 is primarily due to the reinstatement of the credit for the residential return component of the administrative charge on June 1, 2010 and higher distribution volumes.

Electricity Purchased for Resale Expenses

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

	2011	**2010**	**2009**
		(In millions)	
Actual costs	**$ 1,128.3**	$ 1,618.3	$ 1,781.9
Recovery under rate stabilization plans	**56.4**	62.6	59.0
Electricity purchased for resale expenses	**$ 1,184.7**	$ 1,680.9	$ 1,840.9

Actual Costs

BGE's actual costs for electricity purchased for resale decreased $490.0 million for 2011 compared to 2010, primarily due to lower contract prices to purchase electricity for our customers and lower volumes due to an increase in customers using competitive suppliers.

BGE's actual costs for electricity purchased for resale decreased $163.6 million for 2010 compared to 2009, mostly due to lower standard offer service rates and volumes.

Recovery under Rate Stabilization Plans

BGE deferred electricity purchased for resale expenses representing the difference between our actual costs of electricity purchased for resale and what we are allowed to bill customers under our rate stabilization plan. These deferred expenses, plus carrying charges, are included in "Regulatory Assets (net)" in our, and BGE's, Consolidated Balance Sheets.

In late June 2007, we began recovering previously deferred amounts from customers. We recovered $56.4 million, $62.6 million, and $59.0 million in 2011, 2010, and 2009, respectively, 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 $56.5 million in 2011 compared to 2010, primarily due to:

- incremental restoration expenses related to Hurricane Irene of $41.1 million,
- $12.9 million in increased distribution service restoration expenses associated with 2011 winter storms, and
- $7.3 million in higher labor and benefit costs and the impact of inflation on other costs of $3.9 million.

These increases were partially offset by a $12.6 million reduction in operations and maintenance expenses due to incremental restoration expenses associated with 2010 storms and other costs that were deferred as regulatory assets in 2011 as required by the Maryland PSC in its comprehensive rate case order received in March 2011.

Regulated electric operations and maintenance expenses increased $50.3 million in 2010 compared to 2009, primarily due to increased distribution service restoration expenses of $24.2 million, $13.4 million of higher labor and benefits costs, and the impact of inflation on other costs of $12.7 million.

Merger Costs

We discuss costs related to the proposed merger with Exelon in more detail in *Note 2 to Consolidated Financial Statements*. However, BGE will not seek recovery of these costs in rates.

Electric Depreciation and Amortization Expense

Regulated electric depreciation and amortization expense increased $21.3 million during 2011, compared to 2010, primarily due to increased amortization of $13.2 million of deferred Smart Energy Savers Program® costs due to an increase in program surcharges, and an increase in property, plant and equipment depreciation of $9.5 million.

Regulated electric depreciation and amortization expense decreased $12.9 million during 2010, compared to 2009, primarily due to decreased amortization of $22.9 million of deferred Smart Energy Savers Program® costs due to a regulatory change in the deferral period associated with these costs, partially offset by an increase in property, plant and equipment depreciation of $7.0 million.

Taxes Other Than Income Taxes

Taxes other than income taxes increased $5.8 million during 2011 compared to 2010, primarily due to an increase in property taxes of $5.2 million.

Taxes other than income taxes increased $6.2 million during 2010 compared to 2009, primarily due to the absence in 2010 of the impact of lower customer credits on franchise taxes of $95.0 million pre-tax.

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Regulated Gas Business

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

Results

	2011	2010	2009
		(In millions)	
Revenues	**$ 671.7**	$ 709.4	$ 758.3
Gas purchased for resale expenses	**(334.2)**	(387.5)	(449.9)
Operations and maintenance expenses	**(161.0)**	(156.8)	(160.9)
Merger costs	**(7.7)**		
Depreciation and amortization	**(45.6)**	(44.0)	(44.0)
Taxes other than income taxes	**(35.3)**	(34.7)	(34.9)
Income from Operations	**$ 87.9**	$ 86.4	$ 68.6
Net Income	**$ 42.1**	$ 37.6	$ 25.5
Net Income attributable to common stock	**$ 38.7**	$ 34.6	$ 22.5
Other Items Included in Operations (after-tax):			
Merger costs(1)	**$ (4.5)**	$	$
Residential customer rate credit			(10.4)
Total Other Items	**$ (4.5)**	$	$ (10.4)

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.

(1) *BGE will not seek recovery of these costs in rates.*

Net income attributable to common stock from the regulated gas business increased $4.1 million in 2011 compared to 2010, primarily due to an increase in base rate distribution revenues of $5.2 million after-tax resulting from the December 2010 Maryland PSC rate order

Net income attributable to common stock from the regulated gas business increased $12.1 million in 2010 compared to 2009, primarily due to the absence in 2010 of the accrual of a customer rate credit of $10.4 million after-tax recorded in 2009.

Gas Revenues

The changes in gas revenues in 2011 and 2010 compared to the respective prior year were caused by:

	2011 vs. 2010	2010 vs. 2009
	(In millions)	
Distribution volumes	**$ 6.4**	$ 3.1
Base rates	**8.2**	1.6
Residential customer rate credit		17.4
Conservation surcharge	**1.7**	(1.0)
Revenue decoupling	**(5.5)**	(3.1)
Gas cost adjustments	**(50.6)**	(69.1)
Total change in gas revenues from gas system sales	**(39.8)**	(51.1)

Off-system sales	**1.9**	(1.2)
Other	**0.2**	3.4
Total change in gas revenues	**$ (37.7)**	$ (48.9)

Distribution Volumes

The percentage changes in our distribution volumes, by type of customer, in 2011 and 2010 compared to the respective prior year were:

	2011	**2010**
Residential	(7.0)%	1.1%
Commercial	4.5	(3.2)
Industrial	(13.5)	(5.2)

In 2011, we distributed less gas to residential customers due to milder weather, partially offset by increased usage per customer and an increased number of customers. We distributed more gas to commercial customers, mostly due to increased usage per customer and an increased number of customers, partially offset by milder weather. We distributed less gas to industrial customers, mostly due to decreased usage per customer.

In 2010, we distributed more gas to residential customers, mostly due to increased usage per customer and an increased number of customers. We distributed less gas to commercial customers, mostly due to decreased usage per customer. We distributed less gas to industrial customers, mostly due to decreased usage per customer.

Base Rates

On December 6, 2010, the Maryland PSC issued an abbreviated order authorizing BGE to increase gas distribution rates by $9.8 million for service rendered on or after December 4, 2010. This increase was based upon a 7.90% rate of return with a 9.56% return on equity and a 52% equity ratio. We discuss BGE's gas base rates in the *Regulation Maryland Base Rates* section.

Residential Customer Rate Credit

On October 30, 2009, the Maryland PSC issued an order approving Constellation Energy's transaction with EDF. Among other things, the order required Constellation Energy to fund a one-time distribution rate credit for BGE residential customers totaling $110.5 million, or approximately $100 per customer, for which BGE recorded a liability in November 2009. In December 2009, BGE filed a tariff with the Maryland PSC stating BGE would give residential customers a rate credit of exactly $100 per customer. As a result, BGE accrued an additional $1.9 million for a total fourth quarter 2009 accrual of $112.4 million. The portion of this total credit allocated to residential gas customers was $17.4 million pre-tax. This credit was accrued in the fourth quarter of 2009 and applied to BGE residential gas customer bills in the first quarter of 2010.

Conservation Surcharge

Beginning February 2009, the Maryland PSC approved a customer surcharge through which BGE recovers costs associated with certain programs designed to help BGE encourage customer conservation. In 2010, this surcharge was expanded to include the recovery of costs associated with BGE's demand response program.

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Gas Revenue Decoupling

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

Gas Cost Adjustments

We charge our gas customers for the natural gas they purchase from us using gas cost adjustment clauses set by the Maryland PSC as described in *Note 1 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 decreased in both 2011 compared to 2010 and in 2010 compared to 2009 because we sold less gas at lower prices.

Off-System Gas Sales

Off-system gas sales are low-margin direct sales of gas to wholesale suppliers of natural gas. Off-system gas sales, which occur after 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 2011 compared to 2010 primarily due to higher volumes, partially offset by lower prices.

Revenues from off-system gas sales decreased in 2010 compared to 2009 because we sold less gas, partially offset by higher prices.

Gas Purchased For Resale Expenses

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

Gas costs decreased $53.3 million in 2011 compared to 2010 and decreased $62.4 million in 2010 compared to 2009 because we purchased less gas at lower prices.

Gas Operations and Maintenance Expenses

Regulated gas operation and maintenance expenses increased $4.2 million during 2011 compared to 2010, primarily due to higher labor and benefits costs and the impact of inflation.

Regulated gas operation and maintenance expenses decreased $4.1 million during 2010 compared to 2009, primarily due to decreased uncollectible accounts receivable expense of $4.7 million.

Merger Costs

We discuss costs related to the proposed merger with Exelon in more detail in *Note 2 to Consolidated Financial Statements*. However, BGE will not seek recovery of these costs in rates.

Holding Company and Other Nonregulated Businesses

Results

	2011	2010	2009
		(In millions)	
Revenues	**$ 1.7**	$ 1.2	$ 14.4
Operating expenses	**41.6**	53.1	56.5
Impairment losses and other costs			(26.6)
Depreciation and amortization	**(40.4)**	(48.9)	(67.7)
Taxes other than income taxes	**(2.5)**	(3.7)	(4.0)
Gain on divestitures		0.4	
Income (Loss) from Operations	**$ 0.4**	$ 2.1	$ (27.4)
Net Loss	**$ (4.2)**	$ (0.3)	$ (19.7)
Net Loss attributable to common stock	**$ (4.2)**	$ (0.3)	$ (12.4)
Other Items Included In Operations (after-tax):			
Deferred income tax expense relating to federal subsidies for providing post-employment prescription drug benefits	**$**	$ (4.8)	$
Impairment losses and other costs			(11.5)
Total Other Items	**$**	$ (4.8)	$ (11.5)

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 loss attributable to common stock for 2010 decreased $12.1 million compared to 2009 primarily due to the absence in 2010 of an impairment of a district chilled water energy plant of $7.1 million after-tax and reduction for noncontrolling interest, and a write-off of an uncollectible advance to an affiliate of $4.3 million after-tax.

Consolidated Nonoperating Income and Expenses

Other (Expenses) Income

In 2010, we had other expenses of $76.7 million and, in 2009, we had other expenses of $140.7 million. The $64.0 million decrease in 2010 compared to 2009 is mostly due to the absence in 2010 of $62.6 million of other-than-temporary impairment

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charges related to nuclear decommissioning trust fund assets recorded in 2009.

Other income at BGE decreased $4.6 million in 2010 compared to 2009 primarily due to decreases in interest and investment income of $3.3 million.

Fixed Charges

Fixed charges decreased $12.4 million in 2011 compared to 2010 mostly due to a lower level of interest expense due to repayments of debt made in 2010 and in January 2011.

Fixed charges decreased $72.3 million in 2010 compared to 2009 mostly due to a lower level of interest expense due to repayments of debt made in 2009, partially offset by a $51.6 million loss recognized in February 2010 on the retirement of $486.5 million of our 7.00% Notes due April 1, 2012. We discuss this transaction in more detail in *Note 9 to Consolidated Financial Statements*.

Fixed charges at BGE decreased $9.0 million in 2010 compared to 2009 mostly due to a lower level of interest expense due to repayments of debt in 2009.

Income Taxes

Income tax benefit decreased $434.8 million during 2011 compared to 2010 mostly due to a decrease in loss before income taxes as a result of a net decrease in impairment charges recorded of approximately $1.6 billion pre-tax.

Income tax expense decreased $3,652.5 million during 2010 compared to 2009 mostly due to a decrease in income before income taxes as a result of the absence in 2010 of the approximately $7.4 billion gain on sale of our 49.99% membership interest in CENG recorded in 2009 and the recognition of approximately $2.5 billion of impairment charges in 2010.

BGE's income tax expense decreased $23.6 million during 2011, mostly due to a decrease in income before income taxes.

BGE's income tax expense increased $33.3 million during 2010, mostly due to an increase in income before income taxes.

We discuss our, and BGE's, income taxes in more detail in *Note 10 to Consolidated Financial Statements.*

Defined Benefit Plans Funded Status

At December 31, 2011, the total projected benefit obligations of our qualified and nonqualified pension plans exceeded the fair value of our qualified pension plan assets by $327.8 million. At December 31, 2010, the total projected benefit obligations of our qualified and nonqualified pension plans exceeded the fair value of our qualified pension plan assets by $218.0 million. The $109.8 million decrease in the funded status of our pension plans in 2011 primarily reflects a 75 basis point decrease in the discount rate and lower asset returns of $59.3 million.

At December 31, 2011, our accumulated post retirement benefit obligations totaled $347.8 million compared to $334.9 million at December 31, 2010. The $12.9 million increase in obligations for these unfunded plans primarily reflects the 75 basis point decrease in the discount rate at December 31, 2011 compared to December 31, 2010.

We discuss our defined benefit plans in further detail in *Note 7 to Consolidated Financial Statements*.

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Financial Condition

Cash Flows

The following table summarizes our 2011 cash flows by business segment, as well as our consolidated cash flows for 2011, 2010, and 2009.

	2011 Segment Cash Flows				Consolidated Cash Flows		
	Generation	NewEnergy	Regulated	Eliminations, Holding Company and Other	2011	2010	2009
				(In millions)			
Operating Activities							
Net (loss) income	$ (441.1)	$ 2.8	$ 135.7	$ (4.2)	$ (306.8)	$ (931.8)	$ 4,503.4
Non-cash merger costs	33.3	14.3	14.9		62.5		128.2
Derivative contracts classified as financing activities (1)		8.8			8.8	186.0	1,138.3
Gain on U. S. Department of Energy settlement	(58.4)				(58.4)		
Gain on sale of 49.99% membership interest in CENG							(7,445.6)
(Gain) loss on divestitures		(57.3)			(57.3)	(245.8)	468.8
Accrual of BGE residential customer credit							112.4
Impairment losses and other costs	891.0				891.0	2,476.8	124.7
Other non-cash adjustments to net income (loss)	166.2	230.8	413.8	29.6	840.4	156.3	2,761.1
Changes in working capital							
Derivative assets and liabilities, excluding collateral	5.5	769.3	0.5		775.3	449.9	425.3
Net collateral and margin		(250.1)	5.1		(245.0)	44.2	1,522.8
Accrued taxes	101.5	(213.6)	(3.1)	86.1	(29.1)	(809.9)	102.1
Other changes	30.5	(520.3)	(17.3)	(30.8)	(537.9)	(591.5)	664.9
Defined benefit obligations (2)					(21.3)	(234.6)	(264.9)
Other	(73.7)	92.9	(123.4)	36.4	(67.8)	11.7	149.3
Net cash provided by operating activities	654.8	77.6	426.2	117.1	1,254.4	511.3	4,390.8
Investing Activities							
Investments in property, plant and equipment	(126.0)	(389.9)	(538.1)	(52.8)	(1,106.8)	(1,050.3)	(1,529.7)
Asset and business acquisitions, net of cash acquired	(1,084.0)	(417.9)			(1,501.9)	(445.8)	(41.1)
Change in cash pool (3)	732.1	418.6		(1,150.7)			
Contributions to nuclear decommissioning trust funds							(18.7)
Investments in joint ventures							(201.6)
Proceeds from DOE grant			40.6		40.6	54.7	
Proceeds from sale of 49.99% membership interest in CENG							3,528.7
Proceeds from sale of investments and other assets		105.6		0.2	105.8	244.0	88.3
Proceeds from investment tax credits and grants related to renewable energy investments	0.1	81.6			81.7	56.5	
Net payment for issuance of loans receivable	(30.0)				(30.0)		
Contract and portfolio acquisitions		(3.7)			(3.7)	(208.3)	(2,153.7)
Decrease (increase) in restricted funds	50.0	2.3	(0.2)	(0.3)	51.8	(60.3)	1,003.3
Other investments	(9.0)	(8.6)		(0.1)	(17.7)	(35.7)	0.1
Net cash (used in) provided by investing activities	(466.8)	(212.0)	(497.7)	(1,203.7)	(2,380.2)	(1,445.2)	675.6
Cash flows from operating activities plus cash flows from investing activities	$ 188.0	$ (134.4)	$ (71.5)	$ (1,086.6)	(1,125.8)	(933.9)	5,066.4

Financing Activities (2)			
Net issuance (repayment) of debt	246.8	(128.1)	(2,660.4)
Debt and credit facility costs	(3.2)	(32.8)	(98.4)
Proceeds from issuance of common stock	21.1	14.0	33.9
Common stock dividends paid	(182.6)	(183.3)	(228.0)
BGE preference stock dividends paid	(13.2)	(13.2)	(13.2)
Proceeds from contract and portfolio acquisitions	2.0	52.2	2,263.1
Derivative contracts classified as financing activities (1)	(8.8)	(186.0)	(1,138.3)
Other	(0.3)	(0.4)	12.7
Net cash provided by (used in) financing activities	61.8	(477.6)	(1,828.6)
Net (decrease) increase in cash and cash equivalents	$ (1,064.0)	$ (1,411.5)	$ 3,237.8

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

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

3 *As part of the ring-fencing measures required by the Maryland PSC in its 2009 order approving the transaction with EDF, BGE ceased participation in the cash pool on January 7, 2010. We discuss this ring-fencing measure in Note 4 to Consolidated Financial Statements.*

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Cash Flows from Operating Activities

In 2011, cash provided by operating activities of $1.3 billion reflected $0.4 billion from our regulated business and $0.9 billion from our competitive businesses.

The $0.8 billion increase in operating cash flows for 2011 compared to 2010 is primarily due to:

- $1.1 billion lower income tax payments, most of which related to the federal taxes paid in 2010 associated with the EDF transaction that closed in November 2009, and
- $0.3 billion related to changes in net derivative assets and liabilities. Changes in derivative assets and liabilities are driven by fluctuations in commodity prices and the realization of contracts at settlement within our NewEnergy business.

These increases were partially offset by:

- $0.2 billion in lower cash flows related to derivative contract deemed to contain a financing element at inception that are reclassified as financing activities in 2011, and
- $0.3 billion lower net collateral and margin returned in 2011 as compared to 2010 as follows:

	December 31, 2011	December 31, 2010
	(In millions)	
Net collateral and margin held, beginning of year	$ 121.4	$ 77.2
Additional / (Return of) collateral held associated with nonderivative contracts	8.1	(16.1)
Additional collateral posted associated with nonderivative contracts	(18.9)	(7.4)
(Additional) / Return of initial and variation margin posted on exchange-traded transactions recorded in accounts receivable	(349.8)	6.9
Return of fair value net cash collateral posted (netted against derivative assets/liabilities)*	115.6	60.8
Change in net collateral and margin (held) posted	(245.0)	44.2
Net collateral and margin (posted) held, end of year	$ (123.6)	$ 121.4

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

Cash provided by operating activities was $0.5 billion in 2010 compared to cash provided by operating activities of $4.4 billion in 2009. This $3.9 billion decrease in cash flows was primarily due to:

- $1.0 billion higher income taxes paid in 2010,
- $0.3 billion of lower operating cash flows from our regulated businesses in 2010, primarily due to the residential customer rate credit in the first quarter of 2010 and higher distribution service restoration expenses associated with 2010 storms,
- $1.0 billion lower derivative contract settlements reclassified as financing activities in 2010, and
- $1.5 billion lower net collateral and margin returned in 2010 as compared to 2009.

Cash Flows from Investing Activities

Cash used in investing activities was $2.4 billion in 2011 compared to cash used in investing activities of $1.4 billion in 2010. The $1.0 billion increase in cash used in 2011 compared to 2010 was primarily due to the acquisition of Boston Generating's 2,950 MW fleet of generating plants in January 2011, the acquisition of StarTex in May 2011, the acquisition of MXenergy in July 2011, and the acquisition of upstream natural gas working interests in December 2011 as compared to the acquisition of the Colorado Bend Energy Center and Quail Run Energy Center generating plants in May 2010.

Cash used in investing activities was $1.4 billion in 2010 compared to cash provided by investing activities of $0.7 billion in 2009. The $2.1 billion increase in cash used in 2010 compared to 2009 was primarily due to:

- the absence of $3.5 billion of net proceeds received at the closing the sale of a 49.99% membership interest in CENG to EDF in 2009. We discuss this transaction in more detail in *Note 2 to Consolidated Financial Statements*.
- $1.1 billion of lower restricted funds activity in 2010. In January 2009, our restricted funds decreased by $1.0 billion, primarily due to the release of restricted funds for the repayment of $1 billion of 14% Senior Notes to MidAmerican.
- $0.4 billion increase in cash used for asset and business acquisitions. We discuss our acquisitions in the *Note 15 to Consolidated Financial Statements*.

These increases were offset by:

- $1.9 billion lower outflows associated with contract and portfolio acquisitions resulting from the structure of the divestiture of a majority of our international commodities operation in March 2009,
- $0.7 billion of lower investments in property, plant, and equipment and in the CENG and UNE joint ventures, primarily related to environmental additions at our Brandon Shores coal-fired generating plant that went into service in the fourth quarter of 2009 and the absence of nuclear capital spending in 2010 due to the deconsolidation of CENG in 2009, and
- $0.2 billion of higher proceeds from investment tax credits and grants related to renewable energy investments and proceeds on the sale of investments (primarily the sale of our 50% interest in UNE).

Cash Flows from Financing Activities

Cash provided by financing activities was $0.1 billion in 2011 compared to cash used in financing activity of $0.5 billion in

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2010. The decrease in cash used for financing activities of $0.6 billion was primarily due to

- $0.4 billion lower net debt repayments in 2011 compared to 2010. In 2010, we retired $0.5 billion 7.00% Notes due April 1, 2012 pursuant to a cash tender offer and repurchased outstanding Tax Exempt Variable Rate Notes totaling $0.1 billion. In 2011, we retired $0.2 billion of 7.00% Notes due April 1, 2012, and
- $0.2 billion lower cash outflows related to derivative contracts deemed to contain a financing element at inception that must be classified as financing activities rather than operating activities in 2011 compared to 2010.

Cash used in financing activities was $0.5 billion in 2010 compared to cash used in financing activity of $1.8 billion in 2009. The decrease in cash used for financing activities of $1.3 billion was primarily due to:

- $2.5 billion lower net debt repayments in 2010 compared to 2009. In 2009, we repaid $1.0 billion of 14% Senior Notes, $0.8 billion in short-term borrowings on our credit facilities, $0.5 billion of 6.125% Fixed Rate Notes, and $0.3 billion of Zero Coupon Senior Notes. In 2010, we retired $0.5 billion 7.00% Notes due April 1, 2012 pursuant to a cash tender offer and repurchased outstanding Tax Exempt Variable Rate Notes totaling $0.1 billion. These debt retirements were substantially offset by the issuance of $0.6 billion of 5.15% Fixed Rate Notes in December 2010.
- $1.0 billion lower cash outflows related to derivative contracts deemed to contain a financing element at inception that must be classified as financing activities rather than operating activities in 2010 compared to 2009. These contracts primarily related to transactions associated with the divestiture of our Houston-based gas trading operation in March 2009, when we executed transactions at prices that differed from market prices. As a result, for cash flows associated with the out-of-the money derivative transactions executed, we recorded the ongoing cash flows related to these contracts as financing cash flows in March 2009.

This decrease was partially offset by $2.2 billion of lower proceeds from contract and portfolio acquisitions related to the structure of the divestiture of the majority of our international commodities operation in March 2009.

Contract and Portfolio Acquisitions

During 2011 and 2010, our NewEnergy 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 to or from the counterparty at the acquisition of the contract. We paid net cash of $1.7 million in 2011 and $156.1 million in 2010 to acquire various contracts. In 2009, we received net cash of $109.4 million due to the execution of total return swaps to assist in the execution of our divestitures of our international commodities and Houston-based gas trading operations. 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,	**2011**	**2010**	**2009**
		(In millions)	
Financing activities proceeds from contract and portfolio acquisitions	**$ 2.0**	$ 52.2	$ 2,263.1
Investing activities contract and portfolio acquisitions	**(3.7)**	(208.3)	(2,153.7)
Cash flows from contract and portfolio acquisitions	**$ (1.7)**	$ (156.1)	$ 109.4

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. 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 2 to Consolidated Financial Statements.*

Cash Flow Impacts CENG Joint Venture

Prior to November 6, 2009, we recorded 100% of the revenues, expenses, and cash flows from CENG and the nuclear plants it owns because we wholly owned this entity. On November 6, 2009, we completed the sale of a 49.99% membership interest in CENG to EDF, and we deconsolidated CENG. Accordingly, for periods after November 6, 2009, we ceased recording CENG's cash flows and began to record cash flows from our PPA and other transactions with CENG. We will record any future cash flows from distributions received from CENG based on our 50.01% ownership interest, and we may be required to make capital contributions to help fund CENG's capital program.

As a result of deconsolidation, our Generation business cash flows differed from historical cash flows primarily due to the following factors:

- We now sell between 85-90% of the output of CENG's plants, excluding output sold by CENG directly to third parties, rather than 100% of the plants' total output including volumes contracted to third parties.

- Fuel and purchased energy expenses reflect our purchases of the output of CENG's plants, excluding output sold

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directly to third parties, as provided under the terms of the PPA with CENG. We discuss the terms, and subsequent amended terms, of the PPA in *Note 4 to Consolidated Financial Statements*.

Operating expenses no longer include CENG's plant operating costs or general and administrative expenses.

We no longer incur cash flows for 100% of CENG's capital expenditures or the acquisition of nuclear fuel, but we are required to make capital contributions to help CENG fund these expenditures.

We will record cash distributions from CENG if and when such distributions are declared. We did not receive any distributions from CENG in 2011 or 2010.

In addition, we entered into a power services agency agreement (PSA) and an administrative service agreement (ASA) with CENG. The PSA is a five-year agreement under which we will provide scheduling, asset management and billing services to CENG and will recognize average annual revenue of approximately $16 million.

The ASA is a one year agreement that is renewable annually under which we provided administrative support services to CENG for a fee of approximately $48 million for 2011. The level of fees for administrative support services will be subject to change in future years based on the level of services provided. The charges under these agreements are intended to represent the actual cost of the services provided to CENG from us. In October 2010, we entered into a comprehensive agreement with EDF. Among other provisions of the agreement, the ASA was extended through 2017. We discuss the comprehensive agreement with EDF in more detail in *Note 4 to Consolidated Financial Statements*.

In January 2012, Exelon, Exelon Energy Delivery Company, LLC, Constellation Energy, and BGE entered into a settlement agreement with EDF in which the ASA and the PSA will be amended upon the close of the merger with Exelon. We discuss the amendments to the ASA and the PSA in *Note 16 to Consolidated Financial Statements*.

Impact of Security Ratings on Our Liquidity

We rely on access to capital markets as a source of liquidity for capital requirements not satisfied by operating cash flows. Independent credit rating agencies rate Constellation Energy's and BGE's fixed-income securities. These ratings affect how much it will cost us to sell securities and, in certain cases, our ability to access capital markets to sell securities. Generally, the better the rating, the lower the cost of the securities is to us when we sell them. The factors that credit rating agencies consider in establishing Constellation Energy's and BGE's credit ratings include, but are not limited to, cash flows, liquidity, business risk profile, stock price volatility, political, legislative, and regulatory risk, interest charges relative to operating cash flows and the level of debt relative to total capitalization.

At the date of this report, the senior unsecured debt and commercial paper credit ratings for Constellation Energy and BGE were as follows:

	Standard & Poor's Rating Group	**Moody's Investors Service**	**Fitch Ratings**
Constellation Energy			
Outlook	Watch Positive	Positive	Stable
Senior Unsecured Debt	BBB-	Baa3	BBB-
Commercial Paper	A-3	P-3	F3
BGE			
Outlook	Stable	Positive	Stable
Senior Unsecured Debt	BBB+	Baa2	BBB+
Commercial Paper	A-2	P-2	F2

If any of these 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.

We discuss the potential effect of a ratings downgrade in the *Collateral* section.

We discuss the potential effect of a ratings downgrade on our ability to maintain ongoing compliance with financial ratios in our existing credit agreements in *Note 8 to Consolidated Financial Statements.*

As a condition to the October 2009 Maryland PSC order approving our transaction with EDF, Constellation Energy and BGE were required to implement "ring fencing" measures to provide bankruptcy protection and credit rating separation of BGE from Constellation Energy. We completed the implementation of these measures in February 2010.

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.

Available Sources of Funding

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

The primary drivers of our use of liquidity have been our capital expenditure requirements and collateral requirements associated with hedging our generating assets and hedging our NewEnergy business in both power and gas. Significant changes

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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, thereby reducing our available cash balance. Additional regulation of the derivatives markets could also require us to post additional cash collateral. We discuss the financial reform legislation enacted in 2010 in more detail in the *Federal Regulation* section.

We discuss our, and BGE's, credit facilities in detail in *Note 8 to Consolidated Financial Statements*.

Net Available Liquidity

Constellation Energy's (excluding BGE) and BGE's net available liquidity at December 31, 2011 was $3.6 billion and $0.6 billion, respectively. We discuss net available liquidity in more detail in the *Note 8 to Consolidated Financial Statements*.

Collateral

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

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

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

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

- In our NewEnergy business, we generally do not receive collateral under contractual obligations to supply power or gas to our customers but we hedge these transactions through purchases of power and gas that generally require us to post collateral. By entering into a gas supply agreement, we have reduced our collateral requirements to support our retail gas operation. We discuss this gas supply agreement in more detail in *Note 4 to Consolidated Financial Statements*. We also intend to further align our load obligations by buying generation assets in regions where we do not have a significant generation presence and entering into longer-tenor agreements with merchant generators, further reducing our dependence on exchange-traded products, thereby lowering our collateral requirements. During 2010, we acquired generation assets in Texas, and in January 2011, we acquired generation assets in Massachusetts, which will assist with reducing our collateral requirements. One of the expected benefits of our merger with Exelon is the combination of Exelon's large, environmentally advantaged generation fleet and our customer-facing business. This combination is expected to create a platform for growth and enhance our ability to service our load obligations with this generation output, thus further reducing our collateral requirements.

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

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

Customers of our NewEnergy business rely on the creditworthiness of Constellation Energy. In this regard, we have certain agreements that contain provisions that would require us to post additional collateral upon a credit rating downgrade in the senior unsecured debt of Constellation Energy. Based on contractual provisions at December 31, 2011, we estimate that if Constellation Energy's senior unsecured debt were downgraded to one level below the investment grade threshold we would have the following additional collateral obligations:

Credit Ratings Downgraded to (1)

	Level Below Current Rating	Additional Obligations (2)
		(In billions)
Below investment grade	1	$ 1.1

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

(2) *Includes $0.2 billion related to derivative contracts as discussed in Note 13 to Consolidated Financial Statements.*

Based on market conditions and contractual obligations at the time of a downgrade, we could be required to post additional collateral in an amount that could exceed the obligation amounts specified above, which could be material. We discuss our credit facilities in the *Available Sources of Funding* section. In addition, rulemaking under the Dodd-Frank Act could impose additional collateral requirements. We discuss this rulemaking in the *Federal Regulation* section.

Capital Resources

Our actual consolidated capital requirements for the years 2009 through 2011, excluding acquisitions, along with the estimated annual amount for 2012, 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.

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Capital requirements for 2012 and 2013 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,
- severe weather impacts on BGE's infrastructure,
- environmental protection standards,
- the type and number of projects selected for construction or acquisition,
- the effect of economic and market conditions on those projects,
- the cost and availability of capital,
- potential capital contributions to CENG,
- 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.

	2009	2010	2011	2012 (Estimate)
		(In billions)		
Generation and Other Capital Requirements:				
Major Environmental	$ 0.3	$ 0.1	$ 0.1	$
Maintenance	0.6	0.1	0.1	0.1
Growth	0.2	0.1		0.1
Total Generation and Other Capital Requirements	1.1	0.3	0.2	0.2
NewEnergy Capital Requirements:				
Maintenance				0.1
Growth	0.1	0.1	0.3	0.2
Total NewEnergy Capital Requirements	0.1	0.1	0.3	0.3
Regulated Capital Requirements:				
Electric / Gas Distribution	0.3	0.4	0.5	0.4
Electric Transmission		0.1	0.1	0.1
Smart Energy Savers® Initiatives	0.1	0.1	0.1	0.2
Total Regulated Capital Requirements	0.4	0.6	0.7	0.7
Total Capital Requirements	$ 1.6	$ 1.0	$ 1.2	$ 1.2

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

As of the date of this report, we estimate our 2013 capital requirements will be approximately $1.3 billion.

Capital Requirements

Generation and NewEnergy Businesses

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

- maintenance and uprates to the capacity of our generating plants,
- solar projects and upstream natural gas properties,
- costs of complying with the Environmental Protection Agency (EPA), Maryland, and various other states' environmental regulations and legislation, and
- enhancements to our information technology infrastructure.

In addition, in 2011, we made several acquisitions totaling approximately $1.5 billion. We funded these acquisitions primarily through available cash.

In December 2009, we were selected by the State of Maryland to construct, own, operate and maintain a 17 MW solar photovoltaic power installation in Emmitsburg, Maryland. We expect this project to cost us approximately $60 million and be completed by December 2012. Renewable electricity produced by the system will be purchased by the State of Maryland at the site of Mount St. Mary's University under a 20-year solar power purchase agreement.

Regulated Electric and Gas

Regulated electric and gas construction expenditures primarily include new business construction needs, improvements to existing facilities, including projects to improve reliability and support demand response and conservation initiatives, and compliance with the recently enacted Maryland reliability and quality of service standards. Further, BGE continues to invest in transmission projects that earn a FERC authorized rate of return.

In August 2010, the Maryland PSC approved a comprehensive smart grid initiative for BGE which includes the planned installation of 2 million residential and commercial electric and gas smart meters at an expected total cost of approximately $480 million. In 2009, the United States Department of Energy (DOE) selected BGE as a recipient of $200 million in federal funding for our smart grid and other related initiatives. This grant allows BGE to be reimbursed for smart grid and other expenditures up to $200 million, substantially reducing the total cost of these initiatives. As of December 31, 2011, we have received $95.3 million of the $200 million grant from the DOE. If BGE fails to meet its obligation to incur certain costs under the DOE grant or BGE's completion of the smart grid initiative is delayed beyond approved DOE grant deadlines for incurring costs under the grant program, BGE's grant could be impacted, which could substantially increase the total cost for these initiatives.

Funding for Capital Requirements

Generation and NewEnergy Businesses

We expect to fund the capital requirements of our Generation and NewEnergy businesses 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

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additional funding from the money markets, capital markets and lease markets, subject to credit conditions and market liquidity, and, if necessary, from draw downs on credit facilities.

The projects that our Generation and NewEnergy businesses develop typically require substantial capital investment. Many of the qualifying facilities and independent power projects that we have an interest in as well as our upstream properties and certain renewable projects 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 through a combination of internally and externally generated cash. To the extent that internally generated cash is not sufficient to meet those requirements, we would seek additional funding from the short-term and long-term capital markets (including trust preferred securities or preference stock), subject to credit conditions and market liquidity, and, if necessary, from draw downs on credit facilities. BGE may also receive equity contributions from time to time 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 our Generation and NewEnergy 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, 2011 in the following table:

	Payments				
	2012	2013-2014	2015-2016	Thereafter	Total
	(In millions)				
Contractual Payment Obligations					
Long-term debt: (1)					
Nonregulated					
Principal	$ 2.4	$ 155.0	$ 680.9	$ 1,824.6	$ 2,662.9
Interest	139.1	279.6	259.9	2,771.4	3,450.0
Total	141.5	434.6	940.8	4,596.0	6,112.9
BGE					
Principal	172.5	537.0	453.4	1,199.0	2,361.9
Interest	130.1	215.9	175.1	1,151.8	1,672.9
Total	302.6	752.9	628.5	2,350.8	4,034.8
BGE preference stock				190.0	190.0
Operating leases (2)	230.2	448.1	334.2	69.0	1,081.5
Purchase obligations: (3)					
Purchased capacity and energy (4)	501.1	552.5	338.5	335.3	1,727.4
Purchased energy from CENG (5)	1,000.0	2,075.3	1,566.7		4,642.0
Fuel and transportation	656.1	638.6	419.6	321.2	2,035.5
Other	220.6	68.0	46.1	97.8	432.5
Other noncurrent liabilities:					
Uncertain tax positions liability	104.8	13.0	1.2	4.0	123.0
Pension benefits (6)	4.7	204.4	237.1		446.2
Postretirement and post employment benefits (7)	29.3	61.0	64.7	245.9	400.9
Total contractual payment obligations	$3,190.9	$5,248.4	$4,577.4	$ 8,210.0	$21,226.7

(1)

Amounts in long-term debt reflect the original maturity date. Investors may require us to repay $75.0 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) *As part of reaching a comprehensive agreement with EDF in October 2010, we modified our existing power purchase agreement with CENG to be unit contingent through the end of its original term in 2014. Additionally, beginning in 2015 and continuing to the end of the life of the respective plants, we agreed to purchase 50.01% of the available output of CENG's nuclear plants at market prices. We have included in the table our commitments under this agreement for five years, the time period for which we have more reliable data. Further, we continue to own a 50.01% membership interest in CENG that we account for as an equity method investment. See Note 16 in the Consolidated Financial Statements for more details on this agreement.*

(6) *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.*

(7) *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, 2011, we have no material off-balance sheet arrangements, including:

- guarantees with third parties that are subject to initial recognition and measurement requirements,

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- retained interests in assets transferred to unconsolidated entities or similar arrangement that serves as credit, liquidity or market risk support to such entity for such asset,
- 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, 2011, Constellation Energy had a total face amount of $9.3 billion in guarantees outstanding, of which $8.5 billion related to our Generation and NewEnergy 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 $1.5 billion at December 31, 2011, which represents the total amount the parent company could be required to fund based on December 31, 2011 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*.

Risk Management

Introduction

Risk is inherent in our business activities. Constellation Energy is exposed to market, credit, operational, and liquidity risks that are fundamental to our business of providing products and services across the energy value chain. Additionally, our businesses are subject to business and strategic risks, the risks of unsuccessful business performance due to changing economic conditions, competition, regulatory environment, legislation, economic conditions, market liquidity, country or sovereign issues, systems or process failure, and fiscal and monetary policies. These risks exist in our business with varying levels of exposure, and are interrelated and cannot be managed in isolation.

The Company's risk management framework and governance structure are intended to provide appropriate controls and ongoing management of the major risks in our business activities. The risk management framework is also intended to create a culture of risk awareness and personal accountability for risk-taking across the Company. As a result of the extent and diversity of the risks the Company faces in its business operations, we analyze risk and risk concentration 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 economic value, 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. 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.

In this section, we will review the Company's risk practices in terms of our:

- risk governance,
- risk functions, and
- risk exposures.

Risk Governance

Our Board of Directors is responsible for risk oversight of Company activities. The Board of Directors has approved the Company's risk appetite statement and has authorized management to establish risk policies and limits consistent with this statement. The Audit Committee of the Board of Directors periodically reviews compliance with our risk policies and limits and the effectiveness of the related internal controls. The Compensation Committee of the Board of Directors is responsible for oversight of the impact of compensation policies on risk-taking. Management has established the risk appetite statement in the context of the market environment and the Company's business strategy. In setting the risk appetite, the Company takes into consideration factors such as market volatility, product liquidity, business trends, and management experience.

The Company's Risk Management Committee (RMC) is responsible for approving risk management policies and limits consistent with the risk appetite statement, reviewing procedures for the identification, assessment, measurement, and management of risks, and monitoring risk exposures. The RMC meets on a regular basis and is chaired by our Chief Executive Officer. Other committee members are our Chief Risk Officer, Chief Financial Officer, General Counsel, Chief Human Resources Officer, head of Corporate Strategy and Development, head of Corporate Affairs, Public, and Environmental Policy and business unit leaders. In addition, the Chief Risk Officer coordinates with the risk management committees in the business units that meet regularly to identify, assess, and quantify material risk issues and to develop strategies to manage these risks.

Business managers are responsible for managing risks within the established risk appetite, while the Risk Management Group (RMG) is responsible for enforcing compliance with risk management policies and risk limits. The RMG reports to the Chief Risk Officer, who is a member of the Company's Management Committee and who reports to the Chief Executive Officer and the Board of Directors. The Chief Risk Officer provides regular risk management updates to the Audit Committee and the Board of Directors.

In an effort to manage risks, Constellation Energy has established a series of limits at the corporate and business unit level that reflect the Company's risk appetite. 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 unit on an appropriate course of action.

Risk Functions

Risks are managed at the individual and portfolio level of exposure in each business relative to the Company's risk appetite in aggregate and across all major risk types.

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 seven divisions that focus on a specialized area of risk.

Credit Risk Management

Credit Risk Management is responsible for managing the risk of loss inherent in the business units stemming from counterparty or customer failures and adverse market events that effect counterparty creditworthiness. This group supports the business units by establishing credit relationships with various wholesale counterparties and retail customers and facilitating market liquidity with credit limits and appropriate contractual credit terms and conditions. Credit risk managers are responsible for managing credit risk associated with our business activities, including establishing limits and contractual structures, as well as establishing and enforcing credit policies.

Market Risk Management

Market Risk Management is responsible for effectively identifying, quantifying, monitoring, and reporting on impacts of market risk, to include price volatility, correlations, volume uncertainty, market liquidity, interest rate and currency exposure on company businesses. The market risk group also enforces the Market Risk policies and ensures compliance with these policies, including the monitoring, analyzing, and escalating of market risk controls. This group also develops market risk measurement tools, such as stress and scenario tests, gross margin-at-risk, and assists the businesses in implementing market strategies with the highest benefits.

Deal Review, Risk Analytics and Risk Capital

Our Deal Review team performs independent reviews of structured transactions and develops standardized risk-adjusted metrics for assessing these transactions. Our Risk Analytics team provides quantitative support to all risk functions, builds key risk models and metrics, and conducts independent validation of models used by the Company. Our Risk Capital team is responsible for the development and implementation of a framework for the measurement of capital adequacy, risk-based transaction pricing and risk-adjusted performance measurement of our business segments and portfolios. Risk capital, or economic capital, is the level of capital required to offset the effect of unexpected specified stress on the economic value of the Company. It is an assessment of the underlying market, credit, operational, and liquidity risks of the Company's business activities, utilizing internal risk assessment methodologies.

Collateral and Funding Liquidity Risk Management

Collateral Risk Management is responsible for providing an integrated view on credit, market, and company liquidity risks to facilitate Treasury's management of the Company's collateral and overall liquidity position. Funding liquidity risk is the risk that we may be unable to fund our obligations in some future period. This group's responsibilities include measuring and monitoring collateral flows, downgrade collateral needs, and collateral use across the Company. Additionally, this group forecasts expected collateral and liquidity requirements as well as 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. The group also works closely with the Treasury function to plan for expected and contingent liquidity needs based on the Company's long-term business plan.

Operational Risk Management

Operational risk is the risk associated with human error, a failure of process and systems or external factors. RMG staff oversee implementation of a common framework for defining, measuring, monitoring, and reporting operational risks. The integrated risk assessment process involves capturing risk and controls holistically. Accountability for the identification of risks in our business processes resides with business management, who must ensure the completeness and effectiveness of controls and level of residual risk.

Corporate Audit

Corporate Audit assists in ensuring that controls put in place by management to mitigate the risks of the business are adequate and functioning appropriately. This group supports the risk assessment process including the analysis of inherent and residual risk, performs risk-based audits as approved by the Audit Committee of the Board of Directors, and supports the improvement of the effectiveness and efficiency of key business processes.

Special Situations Group

Our Special Situations Group is comprised of two departments: receivables management and credit workout. Receivables management seeks to maximize cash flows from collection efforts for the Company's business units. Its primary function is to mitigate risk by focusing efforts on all aspects of the accounts receivable process including fees related to early termination of energy supply contracts. Credit workout is responsible for the management of distressed customers. These include counterparties in bankruptcy and contractual default. Credit

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workout also seeks to generate cash flows by negotiating early settlement on potential losses and through the sale of impaired assets in the secondary market.

Risk Exposures

We manage risks across all of our businesses. We summarize below the risks we manage within each of our businesses.

Generation and NewEnergy Businesses

Our Generation and NewEnergy businesses are 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, 2011, 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 to Consolidated Financial Statements*.

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.

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 to Consolidated Financial Statements*. At December 31, 2011, 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 credit risk; operational risk and collateral and funding liquidity risk. As previously noted, 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 related commodities. These risks arise from our ownership and operation of power plants, our retail and wholesale customer supply operations, and our origination, risk management, and trading activities. These commodity price risks arise from:

- changes in market volatilities or correlations, and
- changes in interest and foreign exchange 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 Generation and NewEnergy businesses, and if we do not hedge the associated financial exposure, this commodity price volatility could adversely affect our economic value or 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 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, 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.

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 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, historical price relationships, and credit exposure. However, it is likely that future market prices could vary from those used in recording

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derivative assets and liabilities subject to mark-to-market accounting, and such variations could be material.

Power, gas, coal, and other related 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, generating plants, or proprietary positions taken by the Company. We assess and monitor market risk with a variety of tools, including EVaR, VaR, scenario analysis, and stress testing.

EVaR:

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

Positions included in EVaR are comprised of mark-to-market and nonderivative accrual positions that create market risk including:

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

We include the positions related to physical assets to provide a more complete presentation of our commodity market risk exposures. EVaR includes illiquid products and positions for which there is limited price discovery. Modeling the positions in our Generation and NewEnergy businesses involves a number of assumptions, and includes projections of generation, emission rates and costs, customer load growth, load response to weather, and customer response to competitive supply. Changes in our forecast or management estimates will affect the fair value of these positions in a manner not captured by EVaR.

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

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

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

EVaR

For the year ended December 31,	**2011**	**2010**
	(In millions)	
95% Confidence Level, One-Day Holding Period		
Year end	**$ 64.0**	$ 36.3
Average	**55.9**	52.2
High	**73.4**	71.6
Low	**37.3**	34.4

At December 31, 2011, our EVaR was approximately $64.0 million, which represents a 76% increase from its level of $36.3 million on December 31, 2010. The increase in EVaR was primarily due to an increase in price volatility in the fourth quarter of 2011. Several events, including legislative announcements regarding environmental controls, caused an increase in volatility in the power markets. Natural gas price were volatile in 2011 as well due to the rise in shale gas production and unseasonably mild temperatures.

VaR:

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

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

The VaR amounts below represent the potential pre-tax loss in the fair value of our NewEnergy business positions subject to mark-to-market accounting, including both trading and non-trading activities, over one and ten-day holding periods. We experienced higher VaR during 2011 primarily as a result of increased activity in our NewEnergy business due to customer growth and hedging activity for our Generation business.

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Total Mark-to-Market VaR

For the year ended December 31,	**2011**	2010
	(In millions)	
99% Confidence Level, One-Day Holding Period		
Year end	**$ 26.0**	$ 13.6
Average	**18.9**	7.3
High	**28.3**	13.8
Low	**10.2**	4.8
95% Confidence Level, One-Day Holding Period		
Year end	**$ 19.8**	$ 10.4
Average	**14.4**	5.6
High	**21.5**	10.5
Low	**7.8**	3.6
95% Confidence Level, Ten-Day Holding Period		
Year end	**$ 62.6**	$ 32.9
Average	**45.5**	17.7
High	**68.0**	33.2
Low	**24.7**	11.4

Constellation Energy's proprietary trading activities are substantially reduced from previous years. These activities continue to be managed with daily VaR limits, stop loss limits and position limits.

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.

As of December 31, 2011, we have interest rate swaps relating to $700.0 million of our long-term debt. Of the $700.0 million, $550.0 million are fair value hedges that effectively convert our current fixed-rate debt to a floating-rate instrument tied to the three-month London Inter-Bank Offered Rate (LIBOR). Including the $700.0 million in interest rate swaps, approximately 20% of our long-term debt is floating-rate.

We discuss our use of derivative instruments, including interest rate swaps, 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

	2012	**2013**	**2014**	**2015**	**2016**	**Thereafter**	**Total**	**Fair value at December 31, 2011**
				(Dollars in millions)				
Long-term debt								
Variable-rate debt	$ 0.5	$ 0.5	$ 130.5	$ 594.6	$ 83.1	$ 83.1	$ 892.3	$ 892.3
Average interest rate (A)	2.79%	2.79%	3.19%	2.55%	3.69%	1.36%	2.99%	
Fixed-rate debt	$ 174.4	$ 468.6	$ 92.4	$ 76.6	$ 380.0	$ 2,940.5	$ 4,132.5	$ 4,702.8
Average interest rate	6.33%	6.05%	5.31%	5.64%	5.85%	6.35%	6.23%	

(A) *Interest on variable rate debt is included based on the forward curve for interest rates at December 31, 2011 and includes the impact of $550 million of fair value hedges that convert fixed-rate debt to variable-rate debt.*

Security Price Risk

We are exposed to price fluctuations in financial markets primarily through our pension plan assets. In 2011, our actual return on pension plan assets was $89.5 million. We describe our pension funding requirements in more detail in *Note 7 to Consolidated Financial Statements*.

Foreign Currency Risk

Our Generation and NewEnergy businesses are 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 2011, our exposure to foreign currency risk was not material. We manage our exposure to foreign currency exchange rate risk using a foreign currency hedging program. We will continue to have limited exposure to the Canadian dollar due to our Canadian gas and power operations.

Collateral and Funding Liquidity Risk

Funding liquidity risk relates to the ability to fund current and future obligations of the company given variability in collateral requirements as well as variability around working capital requirements and other cash flows that may affect our liquidity. To assess funding liquidity risk, we distinguish between sources and uses of liquidity. Sources of liquidity include projected net available cash and the unused capacity available from our credit facilities. Uses include expected and contingent collateral requirements as well as any unexpected variation of cash flows from projected levels. We define contingent requirements to be any incremental or decremental requirements to expected requirement levels.

To manage liquidity risk, we quantify sources of liquidity and the expected and contingent uses of liquidity both over a short-term and long-term horizon. Contingent uses of liquidity are determined by stress-testing our portfolio using a simulation of extreme, adverse price stresses and measuring their combined impact on collateral needs and on cash flows related to losses due to market and credit risk. Liquidity stresses related to operational risks (weather, plant outages) and other business risks not directly linked to price moves are assessed on a regular basis using scenario analysis. Results of the liquidity assessment are shared regularly with senior management.

Liquidity risk assessment has been integrated into our strategic planning process. Expected and contingent funding needs implied by the business plans of our various business units are first aggregated and compared to available liquidity sources over the planning horizon. Capital and liquidity sources are then allocated to business units based on their business plans, taking into account the cost of providing liquidity. We believe that this integrated view on sources and uses of liquidity allows us to ensure proper funding of the business in accordance with our business plan.

Credit Risk

We are exposed to credit risk through our Generation and NewEnergy businesses and BGE's operations. Credit risk is the loss that may result from counterparties' nonperformance and retail customer accounts receivable and forward value payment risk arising from contracted power and gas supply agreements. We evaluate our credit risk 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 NewEnergy business 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, 2011, our total exposure across our entire wholesale portfolio is $2.1 billion, net of collateral, and includes accrual positions and derivatives. This total exposure has declined from the $2.5 billion as of December 31, 2010, primarily driven by a change in commodity prices and the decrease in our exposure to CENG throughout 2011.

The top ten counterparties account for 50% of our total exposure with 2% of that exposure being non-investment grade. We consider a significant concentration of credit risk to be any single obligor or counterparty whose concentration exceeds 10% of total credit exposure. At December 31, 2011, two counterparties, both large investment grade power cooperatives, together comprised a total exposure concentration of 29%.

As of December 31, 2011 and 2010, counterparties in our NewEnergy credit portfolio had the following public credit ratings, shown as a percentage of the total portfolio exposure:

At December 31,	**2011**	**2010**
Rating		
Investment Grade (1)	**50%**	47%
Non-Investment Grade	**1**	4
Not Rated	**49**	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 billion at December 31, 2011 compared to $1.2 billion at December 31, 2010. This decrease was mostly driven by a reduction in our CENG credit exposure, which is not externally rated.

Many of our not rated counterparties (including CENG) are considered investment grade equivalent based on our internal credit ratings. We utilize internal credit ratings to evaluate the creditworthiness of our wholesale customers, including those companies that do not have public credit ratings. Based on internal credit ratings, approximately $0.9 billion or 88% of the exposure to "Not Rated" counterparties was rated investment grade equivalent at December 31, 2011 and approximately $1.1 billion or 87% was rated investment grade equivalent at December 31, 2010.

The following table provides the breakdown of the credit quality of our wholesale credit portfolio based on our internal credit ratings. This includes those counterparties which are externally rated and those in the "Not Rated" category as a percentage of the total portfolio exposure.

At December 31,	**2011**	**2010**
Investment Grade Equivalent	**92%**	89%

Non-Investment Grade Equivalent	**8**	11

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. 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. To reduce our credit risk with counterparties, we attempt to enter into agreements that allow us to obtain collateral on a contingent basis, seek third party guarantees of the counterparty's obligation, and enter into netting agreements that allow us to offset receivables and payables with forward exposure across many transactions.

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

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 NewEnergy electricity and natural gas supply activities, which serve commercial and industrial companies and governmental entities, 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. In accordance with our credit policy we do not have a significant exposure concentration with any one customer, geographic area or industry.

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. However, we have organized a dedicated credit workout function whose job is to work with distressed customers and recover receivables owed to the company. This also involves negotiating early termination settlements and selling impaired assets in the secondary market.

BGE is subject to retail credit risk associated with both the delivery portion of a customer's bill as well as 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. BGE is also exposed to credit risk associated with the timing of the collection of receivables from those customers who have contracted with a third party supplier where BGE has purchased that supplier's receivables. Although both BGE's delivery and commodity rates include some level of costs for uncollectible customer accounts receivable expenses, full recovery is contingent on amounts approved by the Maryland PSC in customer rates and, therefore is not guaranteed and BGE is exposed to these potential losses and related carrying costs.

Operational Risk

Operational risk is the risk associated with human error or a failure of process and systems, or external factors, as well as the risk of operating owned and contractually controlled generating assets, electric transmission and distribution systems, and gas distribution systems. We are exposed to many types of operational risks, including fraud by employees, clerical and record-keeping errors, and unauthorized data access. Additionally, our asset operations can be effected by those events that are partially or wholly out of our control, like natural disasters, acts of terrorism, and computer application viruses, which may cause losses in generation or service to customers resulting in revenue loss.

We own, have ownership interests in, and operate power generation facilities, which use a diverse mix of fuels including fossil fuels, nuclear and biomass. We are also exposed to variations in the prices for, and required volumes of, natural gas, oil, and coal required to fuel our power plants that 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. These scenarios could potentially lead to a material adverse impact on our financial results.

We are exposed to risk on both sides of the distribution chain, from fuel to end customer delivery, due to inability to produce energy. 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. In addition, 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 potentially result in selling excess energy at lower prices. This could have a material adverse 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, 2011.

Management has excluded MXenergy Holdings, Inc. and Star Electricity, Inc. from its assessment of internal control over financial reporting as of December 31, 2011 because these entities were acquired by the Company during 2011. MXenergy Holdings, Inc. and Star Electricity, Inc. represented approximately 1.9% and 1.1%, respectively, of the Company's total assets as of December 31, 2011 and approximately 0.8% and 1.2%, respectively, of the Company's total revenues for the year ended December 31, 2011.

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, 2011, as stated in their report on the next page.

Mayo A. Shattuck III	Jonathan W. Thayer
Chairman of the Board,	*Senior Vice President and Chief*
President and Chief Executive	*Financial Officer*

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, 2011.

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 an exemption for non-accelerated filers set forth in the Dodd-Frank Wall Street Reform and Consumer Protection Act.

Kenneth W. DeFontes, Jr.	Carim V. Khouzami
President and Chief Executive Officer	*Chief Financial Officer and Treasurer*

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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, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011 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, 2011, 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, 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 require 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 2010 the Company changed its method of accounting for and presenting variable interest entities.

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.

As described in Management's Report on Internal Control over Financial Reporting, management has excluded MXenergy Holdings, Inc. and Star Electricity, Inc., from its assessment of internal control over financial reporting as of December 31, 2011 because these entities were acquired by the Company during 2011. We have also excluded MXenergy Holdings, Inc. and Star Electricity, Inc. from our audit of internal control over financial reporting. MXenergy Holdings, Inc. and Star Electricity, Inc. are wholly owned subsidiaries whose total assets represent 1.9% and 1.1%, respectively, and total revenues represent 0.8% and 1.2%, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2011.

PricewaterhouseCoopers LLP
Baltimore, Maryland
February 29, 2012

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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, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011 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 the 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. An audit includes 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 2010 the Company changed its method of accounting for and presenting variable interest entities.

PricewaterhouseCoopers LLP
Baltimore, Maryland
February 29, 2012

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CONSOLIDATED STATEMENTS OF INCOME (LOSS)

Constellation Energy Group, Inc. and Subsidiaries

Year Ended December 31,	2011	2010	2009
	(In millions, except per share amounts)		
Revenues			
Nonregulated revenues	**$ 10,773.0**	$ 10,883.0	$ 12,024.3
Regulated electric revenues	**2,320.7**	2,752.1	2,820.7
Regulated gas revenues	**664.5**	704.9	753.8
Total revenues	**13,758.2**	14,340.0	15,598.8
Expenses			
Fuel and purchased energy expenses	**9,396.6**	10,001.7	11,013.1
Fuel and purchased energy expenses from affiliate	**888.4**	900.8	122.5
Operating expenses	**1,934.9**	1,691.1	2,228.0
Merger costs	**117.9**		145.8
Impairment losses and other costs	**891.0**	2,476.8	124.7
Workforce reduction costs			12.6
Depreciation, depletion, accretion, and amortization	**589.3**	519.5	651.4
Taxes other than income taxes	**308.0**	263.9	290.4
Total expenses	**14,126.1**	15,853.8	14,588.5
Equity Investment Earnings (Losses)	**19.8**	25.0	(6.1)
Gain on U.S. Department of Energy Settlement	**93.8**		
Gain on Sale of Interest in CENG			7,445.6
Net Gain (Loss) on Divestitures	**57.3**	245.8	(468.8)
(Loss) Income from Operations	**(197.0)**	(1,243.0)	7,981.0
Other Expenses	**(75.3)**	(76.7)	(140.7)
Fixed Charges			
Interest expense	**276.6**	310.8	437.2
Interest capitalized and allowance for borrowed funds used during construction	**(11.2)**	(33.0)	(87.1)
Total fixed charges	**265.4**	277.8	350.1
(Loss) Income from Continuing Operations Before Income Taxes	**(537.7)**	(1,597.5)	7,490.2
Income Tax (Benefit) Expense	**(230.9)**	(665.7)	2,986.8
Net (Loss) Income	**(306.8)**	(931.8)	4,503.4
Net Income Attributable to Noncontrolling Interests and BGE Preference Stock Dividends	**33.5**	50.8	60.0
Net (Loss) Income Attributable to Common Stock	**$ (340.3)**	$ (982.6)	$ 4,443.4
Average Shares of Common Stock Outstanding Basic	**200.1**	200.5	199.3
Average Shares of Common Stock Outstanding Diluted	**200.1**	200.5	200.3
(Loss) Earnings Per Common Share Basic	**$ (1.70)**	$ (4.90)	$ 22.29
(Loss) Earnings Per Common Share Diluted	**$ (1.70)**	$ (4.90)	$ 22.19

Dividends Declared Per Common Share	**$**	**0.96**	$	0.96	$	0.96

See Notes to Consolidated Financial Statements.

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CONSOLIDATED BALANCE SHEETS

Constellation Energy Group, Inc. and Subsidiaries

At December 31,	**2011**	**2010**
	(In millions)	
Assets		
Current Assets		
Cash and cash equivalents	**$ 964.5**	$ 2,028.5
Accounts receivable (net of allowance for uncollectibles of **$87.1** and $85.0, respectively)	**1,907.6**	2,059.2
Accounts receivable consolidated variable interest entities (net of allowance for uncollectibles of **$115.5** and $87.9, respectively)	**247.9**	308.9
Income taxes receivable	**156.6**	152.7
Fuel stocks	**423.1**	361.1
Materials and supplies	**129.6**	104.3
Derivative assets	**357.9**	534.4
Unamortized energy contract assets (includes **$** and $400.9, respectively, related to CENG)	**52.1**	544.7
Restricted cash	**2.3**	52.0
Restricted cash consolidated variable interest entities	**44.8**	52.3
Regulatory assets (net)	**153.7**	78.7
Deferred income taxes	**132.0**	
Other	**246.4**	175.8
Total current assets	**4,818.5**	6,452.6
Investments and Other Noncurrent Assets		
Investment in CENG	**2,150.4**	2,991.1
Other investments	**122.4**	189.9
Regulatory assets (net)	**341.9**	374.1
Goodwill	**282.2**	77.0
Derivative assets	**259.3**	258.9
Unamortized energy contract assets	**58.4**	109.8
Other	**380.5**	284.5
Other consolidated variable interest entities	**95.7**	1.8
Total investments and other noncurrent assets	**3,690.8**	4,287.1
Property, Plant and Equipment		
Nonregulated property, plant and equipment	**7,780.4**	6,387.2
Regulated property, plant and equipment	**7,595.0**	7,201.7
Accumulated depreciation	**(4,472.1)**	(4,310.1)
Net property, plant and equipment	**10,903.3**	9,278.8
Total Assets	**$ 19,412.6**	$ 20,018.5

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,	**2011**	**2010**
	(In millions)	
Liabilities and Equity		
Current Liabilities		
Short-term borrowings	$	$ 32.4
Short-term borrowings consolidated variable interest entities	**39.5**	
Current portion of long-term debt	**109.6**	245.6
Current portion of long-term debt consolidated variable interest entities	**65.3**	59.7
Accounts payable	**924.8**	1,072.6
Accounts payable consolidated variable interest entities	**177.2**	189.8
Customer deposits and collateral	**95.2**	87.2
Derivative liabilities	**779.5**	622.3
Unamortized energy contract liabilities	**118.1**	130.5
Deferred income taxes		56.5
Accrued taxes	**90.4**	71.0
Accrued expenses	**431.4**	358.1
Other	**456.8**	351.5
Total current liabilities	**3,287.8**	3,277.2
Deferred Credits and Other Noncurrent Liabilities		
Deferred income taxes	**2,305.1**	2,489.8
Asset retirement obligations	**37.6**	32.3
Derivative liabilities	**268.4**	353.0
Unamortized energy contract liabilities	**294.8**	411.1
Defined benefit obligations	**698.0**	574.7
Deferred investment tax credits	**23.6**	27.6
Other	**251.7**	296.0
Total deferred credits and other noncurrent liabilities	**3,879.2**	4,184.5
Long-term Debt, Net of Current Portion	**4,456.4**	4,054.2
Long-term Debt, Net of Current Portion consolidated variable interest entities	**388.4**	394.6
Equity		
Common shareholders' equity	**7,093.9**	7,829.2
BGE preference stock not subject to mandatory redemption	**190.0**	190.0
Noncontrolling interests	**116.9**	88.8
Total equity	**7,400.8**	8,108.0
Commitments, Guarantees, and Contingencies (see Note 12)		
Total Liabilities and Equity	**$ 19,412.6**	$ 20,018.5

See Notes to Consolidated Financial Statements.

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CONSOLIDATED STATEMENTS OF CASH FLOWS

Constellation Energy Group, Inc. and Subsidiaries

Year Ended December 31,	2011	2010	2009
		(In millions)	
Cash Flows From Operating Activities			
Net (loss) income	**$ (306.8)**	$ (931.8)	$ 4,503.4
Adjustments to reconcile to net cash provided by operating activities			
Depreciation, depletion, accretion, and amortization	**589.3**	519.5	651.4
Amortization of nuclear fuel			117.9
Amortization of energy contracts and derivatives designated as hedges	**438.0**	319.6	(138.4)
All other amortization	**39.4**	33.3	135.7
Deferred income taxes	**(193.7)**	(716.3)	1,847.0
Investment tax credit adjustments	**(4.3)**	(4.5)	(12.1)
Deferred fuel costs	**5.0**	67.4	68.9
Deferred storm costs	**(15.5)**		
Defined benefit obligation expense	**93.6**	89.4	107.6
Defined benefit obligation payments	**(114.9)**	(324.0)	(372.5)
Merger costs	**62.5**		128.2
Workforce reduction costs			12.6
Impairment losses and other costs	**891.0**	2,476.8	124.7
Impairment losses on nuclear decommissioning trust assets			62.6
Gain on sale of 49.99% membership interest in CENG			(7,445.6)
(Gain) loss on divestitures	**(57.3)**	(245.8)	468.8
Gains on termination of contracts	**(26.9)**	(76.8)	
Gain on U. S. Department of Energy settlement	**(58.4)**		
Accrual of BGE residential customer credit			112.4
Equity in earnings of affiliates less than dividends received	**9.1**	14.1	15.5
Derivative contracts classified as financing activities	**8.8**	186.0	1,138.3
Changes in working capital			
Accounts receivable, excluding margin	**(268.8)**	(236.5)	543.3
Derivative assets and liabilities, excluding collateral	**775.3**	449.9	425.3
Net collateral and margin	**(245.0)**	44.2	1,522.8
Materials, supplies, and fuel stocks	**34.7**	0.1	220.6
Other current assets	**5.5**	(150.0)	217.2
Accounts payable	**(201.4)**	80.0	(1,105.0)
Liability for unrecognized tax benefits	**(40.8)**	(66.6)	102.1
Accrued taxes and other current liabilities	**(96.2)**	(1,028.4)	788.8
Other	**(67.8)**	11.7	149.3
Net cash provided by operating activities	**1,254.4**	511.3	4,390.8
Cash Flows From Investing Activities			
Investments in property, plant and equipment	**(1,106.8)**	(1,050.3)	(1,529.7)
Asset acquisitions and business combinations, net of cash acquired	**(1,501.9)**	(445.8)	(41.1)
Investments in nuclear decommissioning trust fund securities			(385.2)
Proceeds from nuclear decommissioning trust fund securities			366.5
Investments in joint ventures			(201.6)
Proceeds from sale of 49.99% membership interest in CENG			3,528.7
Proceeds from U. S. Department of Energy grant	**40.6**	54.7	
Proceeds from sales of investments and other assets	**105.8**	244.0	88.3
Proceeds from investment tax credits and grants related to renewable energy investments	**81.7**	56.5	
Payment for issuance of loans receivable	**(75.0)**		
Proceeds from repayment of loans receivable	**45.0**		
Contract and portfolio acquisitions	**(3.7)**	(208.3)	(2,153.7)
Decrease (increase) in restricted funds	**51.8**	(60.3)	1,003.3
Other	**(17.7)**	(35.7)	0.1

Net cash (used in) provided by investing activities	**(2,380.2)**	(1,445.2)	675.6
Cash Flows From Financing Activities			
Net repayment of short-term borrowings	**(12.1)**	(13.6)	(809.7)
Proceeds from issuance of common stock	**21.1**	14.0	33.9
Proceeds from issuance of long-term debt	**564.2**	550.0	136.1
Common stock dividends paid	**(182.6)**	(183.3)	(228.0)
BGE preference stock dividends paid	**(13.2)**	(13.2)	(13.2)
Proceeds from contract and portfolio acquisitions	**2.0**	52.2	2,263.1
Repayment of long-term debt	**(305.3)**	(664.5)	(1,986.8)
Derivative contracts classified as financing activities	**(8.8)**	(186.0)	(1,138.3)
Debt and credit facility costs	**(3.2)**	(32.8)	(98.4)
Other	**(0.3)**	(0.4)	12.7
Net cash provided by (used in) financing activities	**61.8**	(477.6)	(1,828.6)
Net (Decrease) Increase in Cash and Cash Equivalents	**(1,064.0)**	(1,411.5)	3,237.8
Cash and Cash Equivalents at Beginning of Year	**2,028.5**	3,440.0	202.2
Cash and Cash Equivalents at End of Year	**$ 964.5**	$ 2,028.5	$ 3,440.0
Other Cash Flow Information:			
Cash paid during the year for:			
Interest (net of amounts capitalized)	**$ 265.3**	$ 289.5	$ 369.5
Income taxes	**$ (66.7)**	$ 1,044.2	$ 57.1

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 COMPREHENISVE INCOME (LOSS)

Constellation Energy Group, Inc. and Subsidiaries

Years Ended December 31, 2011, 2010, and 2009	Common Stock Shares	Common Stock Amount	Retained Earnings	Accumulated Other Comprehensive Loss	Noncontrolling Interests	Total Amount
	(Dollar amounts in millions, number of shares in thousands)					
Balance at December 31, 2008	199,129	$ 3,164.5	$ 2,228.7	$ (2,211.8)	$ 210.1	$ 3,391.5
Contribution from noncontrolling interest					8.0	8.0
Other noncontrolling interest					0.4	0.4
Comprehensive Income						
Net income			4,443.4		60.0	4,503.4
Other comprehensive income						
Hedging instruments:						
Reclassification of net losses on hedging instruments from OCI to net income, net of taxes of $(898.5)				1,499.4		1,499.4
Net unrealized loss on hedging instruments, net of taxes of $251.2				(474.7)		(474.7)
Available-for-sale securities:						
Reclassification of net losses on securities from OCI to net income, net of taxes of $(24.6)				25.4		25.4
Net unrealized gains on securities, net of taxes of $(78.2)				77.7		77.7
Defined benefit plans:						
Prior service cost arising during period, net of taxes of $1.0				(1.5)		(1.5)
Net gains arising during period, net of taxes of $(23.9)				26.9		26.9
Amortization of net actuarial loss, prior service cost, and transition obligation included in net periodic benefit cost, net of taxes of $(19.8)				30.3		30.3
Deconsolidation of CENG joint venture:						
Net unrealized gains on nuclear decommissioning trust funds, net of taxes of $125.3				(125.3)		(125.3)
Net unrealized losses on defined benefit plans, net of taxes of $(94.6)				138.0		138.0
Net unrealized gains on foreign currency translation, net of taxes of $(2.7)				7.1		7.1
Other comprehensive income equity investment in CENG, net of taxes of $(11.7)				12.9		12.9
Other comprehensive income related to other equity method investees, net of taxes of $(1.3)				2.1		2.1
Total Comprehensive Income			4,443.4	1,218.3	60.0	5,721.7
BGE preference stock dividends					(13.2)	(13.2)
Common stock dividend declared ($0.96 per share)			(192.2)			(192.2)
Common stock issued and share-based awards	1,856	65.1	(18.9)			46.2
Balance at December 31, 2009	200,985	3,229.6	6,461.0	(993.5)	265.3	8,962.4
Sale of noncontrolling interest					(17.6)	(17.6)
Distribution from noncontrolling interest					(6.3)	(6.3)
Other noncontrolling interest activity					(0.2)	(0.2)
Comprehensive Income (Loss)						
Net (loss) income			(982.6)		50.8	(931.8)
Other comprehensive income (loss)						
Hedging instruments:						
Reclassification of net losses on hedging instruments from OCI to net income, net of taxes of $(347.5)				582.4		582.4
Net unrealized loss on hedging instruments, net of taxes of $134.6				(233.2)		(233.2)
Available-for-sale securities:						
Reclassification of net gains on securities from OCI to net income, net of taxes of $0.1				(0.1)		(0.1)
Net unrealized gains on securities, net of taxes of $(0.1)				0.1		0.1
Defined benefit plans:						

Prior service cost arising during period, net of taxes of $(1.1)				1.6		1.6
Transition obligation arising during the period, net of taxes of $(0.2)				0.4		0.4
Net losses arising during period, net of taxes of $31.3				(56.6)		(56.6)
Amortization of net actuarial loss, prior service cost, and transition obligation included in net periodic benefit cost, net of taxes of $(15.5)				22.7		22.7
Net unrealized losses on foreign currency translation, net of taxes of $2.2				(6.2)		(6.2)
Other comprehensive income equity investment in CENG, net of taxes of $(14.1)				9.6		9.6
Other comprehensive loss related to other equity method investees, net of taxes of $0.3				(0.5)		(0.5)
Total Comprehensive Income (Loss)			(982.6)	320.2	50.8	(611.6)
BGE preference stock dividends					(13.2)	(13.2)
Common stock dividend declared ($0.96 per share)			(193.8)			(193.8)
Common stock issued and share-based awards	1,304	77.4	(13.8)			63.6
Common stock returned in connection with comprehensive agreement with EDF	(2,500)	(75.3)				(75.3)
Balance at December 31, 2010	199,789	3,231.7	5,270.8	(673.3)	278.8	8,108.0

See Notes to Consolidated Financial Statements.

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Years Ended December 31, 2011, 2010, and 2009	Common Stock Shares	Common Stock Amount	Retained Earnings	Accumulated Other Comprehensive Loss	Noncontrolling Interests	Total Amount
	(Dollar amounts in millions, number of shares in thousands)					
Balance at December 31, 2010	199,789	$ 3,231.7	$ 5,270.8	$ (673.3)	$ 278.8	$ 8,108.0
Noncontrolling interest activity					**7.8**	**7.8**
Comprehensive Income (Loss)						
Net loss			**(340.3)**		**33.5**	**(306.8)**
Other comprehensive income (loss)						
Hedging instruments:						
Reclassification of net losses on hedging instruments from OCI to net income, net of taxes of $(106.4)				**180.8**		**180.8**
Net unrealized loss on hedging instruments, net of taxes of $210.7				**(346.0)**		**(346.0)**
Available-for-sale securities:						
Net unrealized losses on securities, net of taxes of $0.3				**(0.6)**		**(0.6)**
Defined benefit plans:						
Prior service cost arising during period, net of taxes of $0.3				**(0.5)**		**(0.5)**
Net losses arising during period, net of taxes of $68.8				**(105.9)**		**(105.9)**
Amortization of net actuarial loss, prior service cost, and transition obligation included in net periodic benefit cost, net of taxes of $(19.8)				**29.2**		**29.2**
Net unrealized losses on foreign currency translation, net of taxes of $				**(1.5)**		**(1.5)**
Other comprehensive loss equity investment in CENG, net of taxes of $4.1				**(8.7)**		**(8.7)**
Other comprehensive loss related to other equity method investees, net of taxes of $6.0				**(9.8)**		**(9.8)**
Total Comprehensive Income (Loss)			**(340.3)**	**(263.0)**	**33.5**	**(569.8)**
BGE preference stock dividends					**(13.2)**	**(13.2)**
Common stock dividend declared ($0.96 per share)			**(192.4)**			**(192.4)**
Common stock issued and share-based awards	**1,897**	**60.5**	**(0.1)**			**60.4**
Balance at December 31, 2011	**201,686**	**$ 3,292.2**	**$ 4,738.0**	**$ (936.3)**	**$ 306.9**	**$ 7,400.8**

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,	**2011**	**2010**	**2009**
		(In millions)	
Revenues			
Electric revenues	**$ 2,321.4**	$ 2,752.3	$ 2,820.7
Gas revenues	**671.7**	709.4	758.3
Total revenues	**2,993.1**	3,461.7	3,579.0
Expenses			
Operating expenses			
Electricity purchased for resale	**836.5**	1,252.9	1,217.4
Electricity purchased for resale from affiliate	**348.2**	428.0	623.5
Gas purchased for resale	**334.2**	387.5	449.9
Operations and maintenance	**551.5**	484.5	433.7
Operations and maintenance from affiliate	**115.3**	121.6	126.2
Merger costs	**30.3**		
Impairment losses and other costs			20.0
Depreciation and amortization	**272.1**	249.2	262.1
Taxes other than income taxes	**190.2**	183.8	177.8
Total expenses	**2,678.3**	3,107.5	3,310.6
Income from Operations	**314.8**	354.2	268.4
Other Income	**21.0**	20.8	25.4
Fixed Charges			
Interest expense	**133.8**	135.8	143.6
Allowance for borrowed funds used during construction	**(7.2)**	(5.5)	(4.3)
Total fixed charges	**126.6**	130.3	139.3
Income Before Income Taxes	**209.2**	244.7	154.5
Income Taxes			
Current	**(71.3)**	(202.0)	(119.8)
Deferred	**145.8**	300.2	184.7
Investment tax credit adjustments	**(1.0)**	(1.1)	(1.1)
Total income taxes	**73.5**	97.1	63.8
Net Income	**135.7**	147.6	90.7
Preference Stock Dividends	**13.2**	13.2	13.2
Net Income Attributable to Common Stock before Noncontrolling Interests	**122.5**	134.4	77.5
Net Loss Attributable to Noncontrolling Interests			7.3
Net Income Attributable to Common Stock	**$ 122.5**	$ 134.4	$ 84.8

See Notes to Consolidated Financial Statements.

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CONSOLIDATED BALANCE SHEETS

Baltimore Gas and Electric Company and Subsidiaries

At December 31,	**2011**	**2010**
	(In millions)	
Assets		
Current Assets		
Cash and cash equivalents	**$ 48.6**	$ 50.0
Accounts receivable (net of allowance for uncollectibles of **$37.1** and $34.9, respectively)	**323.0**	351.4
Accounts receivable, unbilled (net of allowance for uncollectibles of **$0.6** and $1.0, respectively)	**193.9**	268.8
Accounts receivable, affiliated companies	**1.7**	1.1
Income taxes receivable, net	**21.2**	55.9
Fuel stocks	**73.8**	66.5
Materials and supplies	**33.5**	31.2
Prepaid taxes other than income taxes	**55.7**	51.7
Regulatory assets (net)	**153.7**	78.7
Restricted cash consolidated variable interest entity	**29.7**	29.5
Other	**13.1**	9.5
Total current assets	**947.9**	994.3
Investments and Other Assets		
Regulatory assets (net)	**341.9**	374.1
Receivable, affiliated company	**514.0**	494.3
Other	**53.0**	52.2
Total investments and other assets	**908.9**	920.6
Utility Plant		
Plant in service		
Electric	**5,483.0**	5,127.9
Gas	**1,386.9**	1,323.0
Common	**414.6**	507.8
Total plant in service	**7,284.5**	6,958.7
Accumulated depreciation	**(2,464.8)**	(2,449.3)
Net plant in service	**4,819.7**	4,509.4
Construction work in progress	**298.4**	232.9
Plant held for future use	**12.1**	10.1
Net utility plant	**5,130.2**	4,752.4
Total Assets	**$ 6,987.0**	$ 6,667.3

See Notes to Consolidated Financial Statements.

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CONSOLIDATED BALANCE SHEETS

Baltimore Gas and Electric Company and Subsidiaries

At December 31,	2011	2010
	(In millions)	
Liabilities and Equity		
Current Liabilities		
Current portion of long-term debt	**$ 109.5**	$ 22.0
Current portion of long-term debt consolidated variable interest entity	**63.0**	59.7
Accounts payable	**209.6**	252.9
Accounts payable, affiliated companies	**66.1**	84.9
Customer deposits	**84.0**	78.9
Deferred income taxes	**59.0**	30.1
Accrued taxes	**15.9**	19.0
Accrued interest	**40.8**	41.4
Liability for uncertain tax positions	**10.4**	62.8
Accrued expenses and other	**81.3**	58.3
Total current liabilities	**739.6**	710.0
Deferred Credits and Other Liabilities		
Deferred income taxes	**1,484.2**	1,354.9
Payable, affiliated company	**253.0**	250.8
Deferred investment tax credits	**7.7**	8.4
Other	**15.9**	20.1
Total deferred credits and other liabilities	**1,760.8**	1,634.2
Long-term Debt		
Rate stabilization bonds consolidated variable interest entity	**394.6**	454.4
Other long-term debt	**1,709.6**	1,431.5
6.20% deferrable interest subordinated debentures due October 15, 2043 to wholly owned BGE Capital Trust II relating to trust preferred securities	**257.7**	257.7
Unamortized discount and premium	**(3.5)**	(2.0)
Current portion of long-term debt	**(109.5)**	(22.0)
Current portion of long-term debt consolidated variable interest entity	**(63.0)**	(59.7)
Total long-term debt	**2,185.9**	2,059.9
Equity		
Common shareholder's equity	**2,110.7**	2,073.2
Preference stock not subject to mandatory redemption	**190.0**	190.0
Total equity	**2,300.7**	2,263.2
Commitments, Guarantees, and Contingencies (see Note 12)		
Total Liabilities and Equity	**$ 6,987.0**	$ 6,667.3

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

Baltimore Gas and Electric Company and Subsidiaries

Year Ended December 31,	**2011**	**2010**	**2009**
		(In millions)	
Cash Flows From Operating Activities			
Net income	**$ 135.7**	$ 147.6	$ 90.7
Adjustments to reconcile to net cash provided by operating activities			
Depreciation and amortization	**272.1**	249.2	262.1
Other amortization	**7.3**	5.2	9.2
Deferred income taxes	**145.8**	300.2	184.7
Investment tax credit adjustments	**(1.0)**	(1.1)	(1.1)
Deferred fuel costs	**5.0**	67.4	68.9
Deferred storm costs	**(15.5)**		
Defined benefit plan expenses	**35.7**	36.0	32.7
Allowance for equity funds used during construction	**(15.1)**	(10.5)	(8.2)
Accrual of residential customer rate credit			112.4
Impairment losses and other costs			20.0
Changes in:			
Accounts receivable	**103.4**	(57.6)	(5.1)
Accounts receivable, affiliated companies	**(0.6)**	14.3	(11.1)
Materials, supplies, and fuel stocks	**(9.6)**	8.0	76.4
Income taxes receivable, net	**34.7**	(55.9)	
Other current assets	**(87.6)**	(6.6)	(10.2)
Accounts payable	**(43.3)**	87.5	(65.0)
Accounts payable, affiliated companies	**(18.8)**	(13.4)	1.3
Other current liabilities	**15.3**	(121.5)	62.7
Long-term receivables and payables, affiliated companies	**(53.0)**	(200.8)	(197.8)
Regulatory assets, net	**9.9**	(64.3)	(44.4)
Other	**(89.2)**	(64.9)	67.6
Net cash provided by operating activities	**431.2**	318.8	645.8
Cash Flows From Investing Activities			
Utility construction expenditures (excluding equity portion of allowance for funds used during construction)	**(588.0)**	(551.5)	(372.6)
Proceeds from U.S. Department of Energy grant	**40.6**	54.7	
Change in cash pool at parent		314.7	(165.9)
Proceeds from sales of investments and other assets		20.9	
Increase in restricted funds	**(0.2)**	(5.2)	(0.6)
Net cash used in investing activities	**(547.6)**	(166.4)	(539.1)
Cash Flows From Financing Activities			
Net repayment of short-term borrowings		(46.0)	(324.0)
Proceeds from issuance of long-term debt	**300.0**		
Repayment of long-term debt	**(81.7)**	(56.5)	(90.0)
Debt issuance costs	**(5.1)**	(0.3)	(0.5)
Contribution from noncontrolling interest			8.0
Preference stock dividends paid	**(13.2)**	(13.2)	(13.2)
(Distribution to) contribution from parent	**(85.0)**		315.9

Net cash provided by (used in) financing activities	**115.0**	(116.0)	(103.8)
Net (Decrease) Increase in Cash and Cash Equivalents	**(1.4)**	36.4	2.9
Cash and Cash Equivalents at Beginning of Year	**50.0**	13.6	10.7
Cash and Cash Equivalents at End of Year	**$ 48.6**	$ 50.0	$ 13.6
Other Cash Flow Information:			
Cash paid (received) during the year for:			
Interest (net of amounts capitalized)	**$ 122.3**	$ 127.9	$ 136.9
Income taxes	**$ (53.6)**	$ (76.0)	$ (250.9)

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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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 organized around three business segments: a generation business (Generation), a customer supply business (NewEnergy), and Baltimore Gas and Electric Company (BGE). Our Generation and NewEnergy businesses are competitive providers 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.

Pending Merger with Exelon Corporation

In April 2011, Constellation Energy entered into an Agreement and Plan of Merger with Exelon Corporation (Exelon). We discuss the pending merger in more detail in *Note 15*.

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 in which we own a majority of the voting stock and exercise control over the operations and policies of the company, and
- variable interest entities (VIEs) for which we are the primary beneficiary, 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 four 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 where we hold a significant influence, which generally approximates 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). If our carrying value of the investment differs from our share of the investee's equity, we recognize this basis difference as an adjustment of our

share of the investee's earnings.

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 Ownership Interests

We may sell portions of our ownership interests in a subsidiary's stock. We treat sales of subsidiary stock as an equity transaction and do not recognize any gains or losses on the transaction as long as we retain a controlling financial interest.

When we sell ownership interests in our subsidiaries and do not retain a controlling financial interest, we deconsolidate that subsidiary. Upon deconsolidation, we recognize a gain or loss for the difference between the sum of the fair value of any consideration received and the fair value of our retained investment and the carrying amount of the former subsidiary's assets and liabilities.

On November 6, 2009, we completed the sale of a 49.99% membership interest in Constellation Energy Nuclear Group LLC and affiliates (CENG), our nuclear generation and operation business, to EDF Group and affiliates (EDF). As a result, we ceased to have a controlling financial interest in CENG and deconsolidated CENG at that time. We account for our retained interest in CENG using the equity method. See *Note 2* for the gain recognized in 2009 on our sale of a 49.99% interest in CENG to EDF.

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.

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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.

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,
- 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 made the following reclassifications:

- We have separately presented "Regulatory assets (net)" that was previously presented within "Other current assets" on our Consolidated Balance Sheets.
- We have separately presented "Accrued interest" that was previously presented within "Accrued expenses and other" on BGE's Consolidated Balance Sheet.
- We have separately presented "Proceeds from U.S. Department of Energy grant" that was previously presented within "Utility construction expenditures" on our, and 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, and other commodities, in nonregulated markets;
- sale and delivery of 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 the sale 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 its residential, commercial, and industrial customers. 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, 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. Starting June 1, 2010, BGE is providing all residential electric customers a credit for the residential return component of the administrative charge, which will continue through December 2016.

In May 2010, BGE filed an electric and gas distribution rate case with the Maryland PSC and the Maryland PSC issued an abbreviated order in December 2010. The order authorized BGE to increase electric distribution rates by $31.0 million and was based on an 8.06% rate of return with a 9.86% return on equity and a 52% equity ratio.

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

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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.

In May 2010, BGE filed an electric and gas distribution rate case with the Maryland PSC and the Maryland PSC issued an abbreviated order in December 2010. The order authorized BGE to increase gas distribution rates by $9.8 million and was based on a 7.90% rate of return with a 9.56% return on equity and a 52% equity ratio.

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 competitive retail gas customer supply activities, our fixed quantity competitive retail power customer supply activities for new transactions closed after June 30, 2010, 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 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. 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 competitive 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.

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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.

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 its residential, commercial, and industrial customers. 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. Starting June 1, 2010, BGE is providing all residential electric customers a credit for the residential return component of the administrative charge, which will continue through December 2016.

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 does not earn a profit on the cost of fuel and purchased energy because its 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.

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.

We include in accrual fuel and purchased energy expenses the effects of hedge accounting for derivative contracts that

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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:

Component of Accrual Fuel and Purchased Energy Expense	Nonregulated Physical Energy Delivery	Activity 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 relate to our physical international coal purchase contracts in 2009 and 2008. 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 NewEnergy 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 several possible accounting treatments that meet all of the requirements of the accounting standard. Mark-to-market is 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, both at the time of designation and on an ongoing basis.

The following are 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	Recognition and Measurement: Income Statement
Mark-to-market	Derivative asset or liability recorded at fair value	Changes in fair value recognized in earnings
Cash flow hedge	Derivative asset or liability 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	Derivative asset or liability recorded at fair value Book value of hedged asset or liability adjusted for changes in its fair 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 competitive retail gas customer supply activities, which are managed using economic hedges that we have not designated as cash-flow hedges, in order to match the timing of recognition of the earnings impacts of those activities to the greatest extent permissible, and
- economic hedges of activities that require accrual accounting for which the related hedge requires mark-to-market accounting.

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 NewEnergy businesses) activities because cash flow hedge 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.

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

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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.

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 NewEnergy 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 (cash or letters of credit) 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.

We consider a significant concentration of credit risk to be any single obligor or counterparty whose concentration exceeds 10% of total credit exposure. As of December 31, 2011, two counterparties, both large investment grade power cooperatives, together comprised a total exposure concentration of 29%. No counterparties based in a single country other than the United States in aggregate comprise more than 10% of the total exposure of the portfolio.

Equity Investment Earnings (Losses)

We include equity in earnings from our investments in qualifying facilities and power projects, joint ventures, and Constellation Energy Partners LLC (CEP) in "Equity Investment Earnings (Losses)" in our Consolidated Statements of Income (Loss) in the period they are earned. "Equity Investment Earnings (Losses)" also includes any adjustments to amortize the difference, if any, except for goodwill and land, between our cost in an equity method investment and our underlying equity in net assets of the investee at the date of investment.

We consider our investments in generation-related qualifying facilities, power projects, and joint ventures to be integral to our operations.

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. Under this method, our subsidiaries are allocated their respective share of consolidated income tax liabilities as well as tax benefits attributable to their losses and credits without taking into account the ability of the subsidiary to utilize the tax benefits on a stand-alone basis. 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.

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Tax Credits

We defer the investment tax credits associated with our regulated business, assets previously held by our regulated business, and any investment tax credits that are convertible to cash grants in our Consolidated Balance Sheets. The investment tax credits that are convertible to cash grants are recorded as a reduction to the carrying value of the underlying property and subsequently amortized evenly to earnings over the life of each underlying property. We reduce current income tax expense in our Consolidated Statements of Income (Loss) for any investment tax credits that are not convertible to cash grants and other tax credits associated with our nonregulated businesses.

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.

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*.

Interest and Penalties

We recognize interest and penalties related to tax underpayments, assessments, and unrecognized tax benefits in "Income tax expense (benefit)" in our Consolidated Statements of Income (Loss).

Unrecognized Tax Benefits

We recognize in our financial statements the effects of uncertain tax positions if we believe that these positions are "more-likely-than-not" to be realized. 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.

We discuss our unrecognized tax benefits in more detail in *Note 10*.

State and Local Taxes

State and local income taxes are included in "Income tax expense (benefit)" in our Consolidated Statements of Income (Loss).

Taxes Other Than Income Taxes

Taxes other than income taxes primarily include property and gross receipts taxes along with franchise taxes and other non-income taxes, surcharges, and fees.

BGE and our NewEnergy business collect certain taxes from customers such as sales and gross receipts taxes, along with other taxes, surcharges, and fees that are levied by state or local governments on the sale or distribution of gas and electricity. Some of these taxes are imposed on the customer and others are imposed on BGE and our NewEnergy business. Where these taxes, such as sales taxes, are imposed on the customer, we account for these taxes on a net basis with no impact to our Consolidated Statements of Income (Loss). However, where these taxes, such as gross receipts taxes or other surcharges or fees, are imposed on BGE or our NewEnergy business, we account for these taxes on a gross basis. Accordingly, we recognize revenues for these taxes collected from customers along with an offsetting tax expense, which are both included in our Consolidated Statements of Income (Loss). The taxes, surcharges, or fees that are included in revenues were as follows:

Year Ended December 31,	**2011**	**2010**	**2009**
		(In millions)	
Constellation Energy (including BGE)	**$ 142.7**	$ 122.2	$ 106.8
BGE	**82.9**	81.9	76.8

Earnings Per Share

Basic earnings per common share (EPS) is computed by dividing net income (loss) attributable to common stock by the weighted-average number of common shares outstanding for the 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 in each period, as well as the dilutive common stock equivalent shares as follows:

Year Ended December 31,	**2011**	**2010**	**2009**
		(In millions)	
Non-dilutive stock options	**4.3**	5.6	5.1
Dilutive common stock equivalent shares	**1.8**	1.6	1.0

As a result of the Company incurring a loss for the years ended December 31, 2011 and 2010, diluted common stock equivalent shares were not included in calculating diluted EPS for these reporting periods.

Stock-Based Compensation

Under our long-term incentive plans, we have granted stock options, performance-based units, service-based units, 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*.

We 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. We recognize compensation cost over the period during which an

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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.

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.

Restricted Cash

At December 31, 2011, our restricted cash primarily included cash at one of our consolidated variable interest entities, and BGE's funds restricted for the repayment of the rate stabilization bonds. At December 31, 2010, our restricted cash also included cash held in escrow for the acquisition of the Boston Generating fleet of generating plants.

As of December 31, 2011 and 2010, BGE's restricted cash primarily represented funds restricted at its consolidated variable interest entity for the repayment of the rate stabilization bonds. We discuss the rate stabilization bonds in more detail in *Note 9*.

Financial Investments

In *Note 4*, we summarize the financial investments that are in our Consolidated Balance Sheets.

We report our debt and equity securities 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 trust assets securing certain executive benefits that are classified as available-for-sale securities.

We include any unrealized gains (losses) on our available-for-sale securities in "Accumulated other comprehensive loss" in our Consolidated Statements of Common Shareholders' Equity and Comprehensive Income (Loss).

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. 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.

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. 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. Undiscounted expected future cash flows for proved gas properties include risk-adjusted probable and possible reserves.

We record an impairment loss if the undiscounted expected future cash flows are less than the carrying amount of the asset. The amount of the impairment loss we record equals the difference between the estimated fair value of the asset and its carrying amount in our accounting records.

We evaluate unproved gas producing properties at least annually to determine if they are impaired. 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.

Investments

We evaluate our equity method and cost method investments to determine whether or not they are impaired. The standard for determining whether an impairment must be recorded is whether the investment has experienced an "other than a temporary" decline in value.

Additionally, if the projects in which we hold these investments recognize an impairment, we would record our proportionate share of that impairment loss and would evaluate our investment for an other than temporary decline in value.

We continuously monitor issues that potentially could impact future profitability of our equity method investments that own coal, hydroelectric, fuel processing projects, as well as our equity investment in our nuclear joint venture. These issues include environmental and legislative initiatives.

Debt and Equity Securities

We determine whether a decline in fair value of a debt or equity 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.

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 do not amortize goodwill. We 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 our businesses 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. We amortize 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.

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 Conemaugh substation and 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 $345.2 million at December 31, 2011 and $338.0 million at December 31, 2010. 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 $162.5 million at December 31, 2011 and $108.3 million at December 31, 2010.

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. Costs of drilling exploratory wells are initially capitalized and later charged to expense if reserves are not discovered or deemed not to be commercially viable. Other exploratory costs are charged to expense when incurred.

Depreciation and Depletion Expense

We compute depreciation for our generating, electric transmission and distribution, and gas distribution facilities. We compute depletion for our oil and gas exploitation and production activities. Depreciation and depletion are determined using the following methods:

- the group straight-line method using rates averaging approximately 3.2% per year for our non-solar generating assets,
- the individual straight-line method using a 30-year life for solar generating assets,

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 2.8% per year for our regulated business, 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	3 - 50 years
Office equipment and furniture	3 - 21 years
Transportation equipment	5 - 15 years
Computer software	3 - 15 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 asset's useful life. When we reduce amounts in our Consolidated Balance Sheets, we record 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

We recognize an estimated liability for legal obligations and legal obligations conditional upon a future event associated with the retirement of tangible long-lived assets. Our conditional asset retirement obligations relate primarily to asbestos removal at certain of our generating facilities.

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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.

Capitalized Interest and Allowance for Funds Used During Construction

Capitalized Interest

Our nonregulated businesses capitalize 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 for 2011 were 8.06% for electric distribution plant, 8.92% for electric transmission plant, 7.90% for gas plant, and 8.13% 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 costs related to long-term debt into interest expense over the life of the debt. We amortize costs related to credit facilities to other (expenses) income over the terms of the facilities.

In addition to the fees that are paid upfront for credit facilities, we also incur ongoing fees related to these facilities. We record the ongoing fees in other (expense) income, and we record interest incurred on cash draws in interest expense.

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

Asset and Liability Netting

In December 2011, the Financial Accounting Standards Board (FASB) issued updated disclosure requirements regarding the netting of certain assets and liabilities, including derivatives. Entities will be required to disclose both gross information and net information about instruments and transactions eligible for offset in the balance sheet and instruments and transactions subject to master netting agreements. The new requirements will be effective for us as of January 1, 2013. The adoption of this update will not impact our, or BGE's, financial results; however, it will result in additional disclosures.

Comprehensive Income

In June 2011, the FASB issued updated requirements on the presentation of comprehensive income which eliminate the option to present other comprehensive income in the statement of changes in equity. The new requirements will be effective for us as of January 1, 2012. The adoption of this amendment will not have an impact on our, or BGE's financial results, other than the presentation of a separate statement of comprehensive income.

Fair Value Measurements

In May 2011, the FASB issued updated guidance on fair value measurements and disclosure requirements. The update aligns the accounting requirements for fair value measurements under generally accepted accounting principles in the United States and international financial reporting standards. The new requirements will be effective for us as of January 1, 2012. The adoption of this update will not have a material impact on our, or BGE's financial results; however, it will result in additional disclosures.

Accounting Standards Adopted

Accounting for Variable Interest Entities

In June 2009, the FASB amended the accounting, presentation, and disclosure guidance related to variable interest entities.

The amended standard includes the following significant provisions:

- requires an entity to qualitatively assess whether it should consolidate a VIE based on whether the entity (1) has the power to direct matters that most significantly impact the activities of the VIE, and (2) has the obligation to absorb losses or the right to receive benefits of the VIE that could potentially be significant to the VIE,
- requires an ongoing reconsideration of this assessment instead of only upon certain triggering events,
- amends the events that trigger a reassessment of whether an entity is a VIE, and
- requires the entity that consolidates a VIE
(the primary beneficiary) to present separately on the face of its balance sheet (1) the assets of the consolidated VIE, if they can be used to only settle specific obligations of the consolidated VIE, and (2) the liabilities

of a consolidated VIE for which creditors do not have recourse to the general credit of the primary beneficiary.

We adopted this guidance on January 1, 2010 and, as a result of our assessment and implementation of the new requirements, our accounting and disclosures related to VIEs were impacted as follows:

- We have presented separately on our Consolidated Balance Sheets, to the extent material, the assets of our consolidated VIEs that can only be used to settle specific obligations of the consolidated VIE, and the liabilities of our consolidated VIEs for which creditors do not have recourse to our general credit.

- The new requirements emphasize a qualitative assessment of whether the equity holders of the entity have the power to direct matters that most significantly impact the entity. We have evaluated all existing entities under the new VIE accounting requirements, both those previously considered VIEs and those considered potential VIEs. Our accounting for and disclosure about VIEs did not change materially as a result of these assessments.

We discuss our investments in variable interest entities in more detail in *Note 4*.

Noncontrolling Interests in Consolidated Financial Statements

Effective January 1, 2009, we adopted guidance relating to the accounting and reporting of noncontrolling interests in consolidated financial statements. We presented and disclosed our noncontrolling interests in our Consolidated Financial Statements, and we accounted for the 2009 sale of a 49.99% membership interest in CENG to EDF by deconsolidating CENG, measuring our retained interest at fair value, and recognizing a gain at closing. We discuss this transaction in more detail in *Note 2*.

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2 Other Events

2011 Events

		Pre-Tax		After-Tax
		(In millions)		
Impairment losses and other costs	$	(891.0)	$	(530.2)
Impact of power purchase agreement with CENG		(200.4)		(118.5)
Amortization of basis difference in CENG		(153.1)		(90.5)
Gain on settlements with U.S. Department of Energy		93.8		57.3
Gain on divestitures		57.3		32.7
Merger costs		(117.9)		(70.9)
Transaction fees for Boston Generating acquisition		(15.5)		(9.9)
Total other items	$	(1,226.8)	$	(730.0)

Impairment Losses and Other Costs

Impairment Evaluations

We discuss our policy for 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 and cost method investments, and goodwill when events occur that indicate that the potential for an impairment exists.

A decrease in long-term forward power prices is a significant event that could result in us performing an impairment evaluation for our generating assets (including those held in equity and cost method investments). One of the primary drivers of forward power prices is forward natural gas prices. A decrease in forward power prices lowers the expected future cash flows from the long-lived asset or equity and cost method investments since sales of power would occur at lower prices and generate lower revenues.

During the fourth quarter of 2011, the following events that lower expected future cash flows resulted in the need for us to perform impairment evaluations of certain of our equity and cost method investments as well as certain of the power plants we own:

- natural gas prices declined approximately 19% during the fourth quarter of 2011 primarily due to an increase in supply, and negatively impacted forward power prices,
- increased uncertainty around the timing and extent of federal carbon legislation also negatively impacted forward power prices,
- changes in the pricing structure for power sales from our power projects and qualifying facilities in California and Utah to reflect lower market-based pricing,
- decreased prices for solar renewable energy credits primarily due to an increase in supply, and
- forecasted additional expenses for a facility in Pennsylvania to comply with the EPA's recent emission regulations.

As a result of these evaluations, we recorded impairments of several of our equity and cost method investments. We describe the impairment evaluations we performed in the following sections.

Equity Method Investments

We evaluated certain of our equity method investments in light of recent declines in commodity prices. The investments we evaluated include our investment in CENG and our investments in certain qualifying facilities.

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 to recover the carrying amount of our investment. 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.

CENG

As of December 31, 2011, the estimated fair value of our investment in CENG was $2.2 billion, which was lower than its carrying value of $3.0 billion.

There is no active market for ownership interests in CENG or comparable entities that solely own and operate nuclear power plants. Therefore, we were required to exercise significant judgment in estimating the fair value of our investment based upon information that a market participant would consider. We believe our estimate incorporates the best data available as of December 31, 2011 for each input, which we describe below. However, the resulting fair value amount remains an estimate and is subject to change in the future based upon changes in any of the inputs or the underlying operating, market, and economic conditions we considered.

Because of the absence of relevant market transactions for similar entities, we estimated the fair value of CENG using discounted future cash flows based upon inputs that we believe reflect a market participant's perspective. Our methodology was consistent with the methodology used to estimate fair value in September 2010, when we previously recorded an impairment of our investment. The most significant inputs to our estimate of fair value include expectations of nuclear plant performance, future power prices, nuclear fuel and operating costs, forecasted capital expenditures, existing power sales commitments and a discounting factor reflective of an investor's required risk-adjusted return. To the extent possible, we considered available market information and other third-party data for each of the inputs. However, because of the long operating lives of nuclear power plants, we were required to estimate inputs for many years beyond periods for which observable market data is available. Additionally, we compared the inputs to relevant historical information, and we benchmarked our valuation using implied market data of other companies that own nuclear generation facilities.

Upon completion of our evaluation, we determined that the fair value of our investment in CENG had declined by approximately $0.8 billion on a pre-tax basis as of December 31,

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2011. The decline in fair value is primarily attributable to the following factors:

- significant and sustained declines in forward power and capacity prices that continued into the fourth quarter of 2011,
- continued decreases in the market price of natural gas, particularly in the fourth quarter of 2011, that adversely impact the level of and potential for recovery in power prices in the near term,
- delays in timing and increased uncertainty regarding the timing and provisions of carbon emissions reduction and other potential environmental legislation that reduced estimates of long-term future power prices in the fourth quarter of 2011.

Based upon the extent of the decline below carrying value, the fundamental reasons for and the sustained nature of the decline, and our assessment that a sufficient improvement in these factors necessary to produce a recovery in fair value is not likely to occur in the near term, we determined that the decline in fair value is other than temporary. Therefore, we recorded an $824.2 million pre-tax impairment charge during the quarter ended December 31, 2011 to write-down our investment to fair value as of that date. We recorded this charge in "Impairment losses and other costs" in our Consolidated Statements of Income (Loss). To the extent that the fair value of our investment declines further in future quarters, we may record additional write-downs if we determine that any additional declines are other than temporary.

Qualifying Facilities

As a result of the changes in the pricing structure for qualifying facilities in California and Utah to more of a market based mechanism coupled with the significant decline in forward prices for natural gas in the fourth quarter of 2011, we determined that the fair values of certain of our equity and cost method investments declined substantially below book value. Also, the expected additional cost of complying with the EPA's recent emission regulations coupled with the decline in natural gas prices in the fourth quarter caused the fair value of one of our waste coal facilities in Pennsylvania to decline substantially below book value. As a result, we recorded a $66.8 million pre-tax impairment charge during the quarter ended December 31, 2011 to write down these investments to fair value as of that date.

We recorded these charges in the "Impairment losses and other costs" line in our Consolidated Statements of Income (Loss).

Generating Plants

We evaluated the impact of the events that occurred during the fourth quarter of 2011 on the recoverability of certain of our wholly owned generating plants. As discussed in *Note 1*, we evaluated whether these plants would generate undiscounted cash flows from operations that are at least sufficient to recover the carrying value of our investment. Based upon our consideration of these events, we determined that our generating plants were not impaired as of December 31, 2011.

Goodwill

We performed our annual impairment review in the quarter ended September 30, 2011 and determined that our goodwill is not impaired. The events of the fourth quarter were not considered triggering events for our goodwill as all of our goodwill is recorded within our retail energy reporting unit within our NewEnergy business segment. For this reporting unit, fair value is primarily impacted by changes in customer margins, which did not materially change in the fourth quarter of 2011.

Impact of Power Purchase Agreement with CENG

In connection with the closing of the CENG membership sale transaction with EDF in 2009, we entered into a five year power purchase agreement (PPA) with CENG with an initial fair value of $0.8 billion.

Based on energy prices at the time of closing of the EDF transaction, we recorded the approximately $0.8 billion "Unamortized energy contract asset" for the value of our PPA with CENG, and CENG recorded an approximately ($0.8) billion "Unamortized energy contract liability." Both entities are amortizing these amounts over the initial two years of the five-year term of the PPA, with the total net economic value to be realized by us in the form of lower purchased power costs equal to approximately $0.4 billion as a result of our 50.01% ownership interest in CENG. During 2011, we realized approximately $200.4 million pre-tax in economic value relating to its PPA with CENG.

Amortization of Basis Difference in CENG

On November 6, 2009, Constellation Energy sold a 49.99% membership interest in CENG to EDF for total consideration of approximately $4.7 billion (includes $3.5 billion in cash at close, the non-cash redemption of the $1.0 billion Series B Preferred Stock held by EDF, and certain expense reimbursements). As a result, we ceased to have a controlling financial interest in CENG and deconsolidated CENG in the fourth quarter of 2009.

On November 6, 2009, we began to account for our retained investment in CENG using the equity method and report our share of its earnings in our Generation business segment. As a result, we no longer record the individual income statement line items, but instead record our share of the investment's earnings in a single line in our Consolidated Statements of Income (Loss).

We had an initial basis difference of approximately $3.9 billion between the initial carrying value of our investment in CENG and our underlying equity in CENG. This basis difference was caused by the requirement to record our investment in CENG at fair value at closing while CENG's assets and liabilities retained their carrying value. We are amortizing this basis difference over the respective useful lives of the assets of CENG or as those assets impact the earnings of CENG.

Beginning in the fourth quarter of 2010, the amortization of the basis difference in CENG is lower as the basis difference was reduced by the amount of the impairment charge recorded on our investment in CENG during the quarter ended

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September 30, 2010. The new basis difference as of September 30, 2010 was $1.5 billion.

For the year ended December 31, 2011, we recorded $153.1 million of pre-tax basis difference amortization as a reduction to our equity investment earnings in CENG. The impairment recorded in the fourth quarter of 2011 will further reduce the basis difference and, therefore, will reduce future amortization of the basis difference. The basis difference as of December 31, 2011 is $453.1 million. We discuss the components of our equity investment earnings in *Note 4*.

Gain on U.S. Department of Energy Settlements

On June 30, 2011, CENG executed settlement agreements with the United States Department of Energy (DOE) which settled lawsuits involving the Calvert Cliffs nuclear power plant that sought to recover damages caused by the DOE's failure to comply with legal and contractual obligations to dispose of spent nuclear fuel. A similar settlement was reached related to the Ginna nuclear power plant. These agreements detail a framework and procedure for recovery of damages incurred or to be incurred through the end of 2013.

As part of the 2009 agreement between Constellation Energy and EDF that established CENG as a joint venture, Constellation Energy retained the right to receive any such payments for a settlement with the DOE that related to periods prior to the formation of the joint venture on November 6, 2009. Therefore, any funds received from the DOE that represent the settlement of claims incurred through November 6, 2009, the date we sold a 49.99% membership interest in CENG to EDF, will belong to us, and any funds representing the settlement of claims incurred after November 6, 2009 will belong to CENG.

CENG records the receipt of funds from settlements with the DOE as offsets to the accounts where costs were originally charged. For those costs that were originally charged to expense, the offset of those costs will be recognized as part of CENG's earnings, of which Constellation Energy records its 50.01% share.

During 2011, Constellation Energy, through its share of the settlements, recognized the following pre-tax gains as operating income for costs incurred through November 6, 2009 to store spent nuclear fuel:

- $39.4 million related to the Calvert Cliffs nuclear power plant, and
- $54.4 million related to the Ginna nuclear power plant.

The lawsuit relating to the storage of spent nuclear fuel at the Nine Mile Point nuclear power plant remains outstanding.

Gain on Divestitures

Upstream Gas Property

In December 2011, we sold all of our interests in a subsidiary that owned natural gas and oil assets in the south Texas region to Petrohawk Energy Corporation for $93.0 million. Our NewEnergy business recognized a pre-tax gain of $23.0 million on this sale.

We also sold working interests in another natural gas property in the Texas region and recognized a $0.6 million gain.

These gains are recorded on the "Net Gain on Divestiture" line on the Consolidated Statements of Income (Loss).

Constellation Energy Partners LLC

In August 2011, we sold a majority of our interests in Constellation Energy Partners LLC (CEP) to PostRock Energy Corporation (PostRock). Under the terms of the agreement, PostRock received all of our Class A member interests, which includes the right to appoint two of the five members of CEP's board of directors, and approximately 3.1 million units of our Class B member interests. In return, we received $6.6 million in cash, one million shares of PostRock common stock and warrants to acquire an additional 673,822 shares of PostRock common stock. As a result of this August transaction, we recorded a pre-tax gain of $11.4 million in the "Net Gain on Divestitures" line in our Consolidated Statements of Income (Loss).

Immediately following this transaction, we still retained a portion of the voting Class B member interests (approximately 2.8 million units) and other classes of non-voting member interests in CEP. However, since we no longer had significant influence over CEP's activities following the August 2011 sale, our retained interests did not qualify for the equity method of accounting. Upon the cessation of equity method accounting, we reclassified our remaining balance in accumulated other comprehensive income to earnings, recognizing a pre-tax gain of $11.6 million in the "Net Gain on Divestitures" line in our Consolidated Statements of Income (Loss).

In December 2011, we sold all of our remaining Class B member interests in CEP to PostRock for $6 million cash. Upon completion of this transaction, we reclassified into earnings $4.7 million of gain that was previously deferred in 2008 as a result of a sale of upstream assets to CEP from us. As a result of this December transaction, we recorded a pre-tax gain of $10.7 million in the "Net Gain on Divestitures" line in our Consolidated Statements of Income (Loss).

Merger Costs

On April 28, 2011, Constellation Energy entered into an Agreement and Plan of Merger with Exelon Corporation (Exelon). At closing, each issued and outstanding share of common stock of Constellation Energy will be cancelled and converted into the right to receive 0.93 shares of common stock of Exelon, and Constellation Energy will become a wholly owned subsidiary of Exelon. We discuss the terms of the pending merger in more detail in *Note 15*.

During 2011, we incurred $117.9 million pre-tax in costs directly related to our pending merger with Exelon, primarily relating to investment banking fees, legal fees, consulting fees, and employee-related expenses. Of this amount, $30.3 million pre-tax related to BGE. BGE will not seek recovery of these costs in rates.

Transaction Fees for Boston Generating Acquisition

In January 2011, we acquired Boston Generating's 2,950 MW fleet of generating plants for cash of $1.1 billion. We discuss this acquisition in more detail in *Note 15*.

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During 2011, we incurred $15.5 million pre-tax in costs related to this acquisition.

2010 Events

	Pre-Tax	After-Tax
	(In millions)	
Impairment losses and other costs	**$ (2,476.8)**	**$ (1,487.1)**
International coal contract dispute settlement	**56.6**	**35.4**
Deferred income tax expense relating to federal subsidies for providing post-employment prescription drug benefits		**(8.8)**
Amortization of basis difference in CENG	**(195.2)**	**(117.5)**
Loss on early retirement of 2012 Notes	**(51.6)**	**(30.9)**
Impact of power purchase agreement with CENG	**(185.6)**	**(113.3)**
Gain on divestitures	**240.0**	**146.0**
Total other items	**$ (2,612.6)**	**$ (1,576.2)**

Impairment Losses and Other Costs

Impairment Evaluations

We discuss our policy for 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 and cost method investments, and goodwill when events occur that indicate that the potential for an impairment exists.

During the third quarter of 2010, the following events resulted in the need for us to perform impairment evaluations of our equity method investments as well as the power plants we own:

- commodity prices declined substantially,
- there was a decrease in certainty around the timing and extent of environmental legislation,
- we completed a process that led us to reject the terms and conditions of a Department of Energy (DOE) loan guarantee related to the development of a new nuclear power plant, and
- with respect to our investments in UNE and CENG, certain contractual issues with our partner remained unresolved as of the end of the third quarter of 2010.

As a result of these evaluations, we recorded impairments of several of our equity method investments. We describe the impairment evaluations we performed in the following sections.

Equity Method Investments

We evaluated certain of our equity method investments in light of recent declines in commodity prices and the completion of the process that led to our rejection of the terms and conditions of the DOE loan guarantee for the development of new nuclear assets. The investments we evaluated include our investment in CENG, our investment in UNE, and our investments in certain qualifying facilities.

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 to recover the carrying amount of our investment. 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.

CENG

As of September 30, 2010, the estimated fair value of our investment in CENG was $2.9 billion, which was lower than its carrying value of $5.2 billion. The carrying value of our investment reflected fair value as of the November 9, 2009 closing of EDF's investment in CENG. At that time, we were required to deconsolidate CENG and record our retained investment at fair value.

There is no active market for the ownership interests in CENG or comparable entities that solely own and operate nuclear power plants. Therefore, we were required to exercise significant judgment in estimating the fair value of our investment based upon information that a market participant would consider. We believe our estimate incorporates the best data available as of September 30, 2010 for each input, which we describe below. However, the resulting fair value amount remains an estimate and is subject to change in the future based upon changes in any of the inputs or the underlying operating, market, and economic conditions we considered.

Because of the absence of relevant market transactions for similar entities, we estimated the fair value of CENG using discounted future cash flows based upon inputs that we believe reflect a market participant's perspective. Our methodology was consistent with the methodology used to estimate fair value in November 2009. The most significant inputs to our estimate of fair value include expectations of nuclear plant performance, future power prices, nuclear fuel and operating costs, forecasted capital expenditures, existing power sales commitments and a discounting factor reflective of an investor's required risk-adjusted return. To the extent possible, we considered available market information and other third-party data for each of the inputs. However, because of the long operating lives of nuclear power plants, we were required to estimate inputs for many years beyond periods for which observable market data is available. Additionally, we compared the inputs to relevant historical information, and we benchmarked our valuation using implied market data of other companies that own nuclear generation facilities.

Upon completion of our evaluation, we determined that the fair value of our investment in CENG had declined by approximately $2.3 billion on a pre-tax basis as of September 30, 2010. The decline in fair value is primarily attributable to the following factors:

- significant declines in power prices, particularly in the third quarter of 2010,

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- decreases in the market price of natural gas that adversely impact the level of and potential for recovery in power prices in the near term,
- uncertainty regarding the timing and provisions of carbon and other potential environmental legislation negatively impacting estimated future power prices, and
- an increase in the discount rate reflecting higher risk-adjusted required returns for nuclear power plants.

Based upon the extent of the decline below carrying value, the fundamental reasons for the decline, and our assessment that a sufficient improvement in these factors necessary to produce a recovery in fair value is not likely to occur in the near term, we determined that the decline is other than temporary. Therefore, we recorded an approximately $2.3 billion pre-tax impairment charge during the quarter ended September 30, 2010 to write-down our investment to fair value as of that date. We recorded this charge in "Impairment losses and other costs" in our Consolidated Statements of Income (Loss). To the extent that the fair value of our investment declines further in future quarters, we may record additional write-downs if we determine that any additional declines are other than temporary.

UNE

As of September 30, 2010, the estimated fair value of our investment in UNE was zero as compared to its carrying value of $143.4 million.

Prior to the third quarter of 2010, we believed that we would recover our investment in UNE through the development and operation of a new nuclear power plant. However, during the third quarter of 2010, several factors led to a decline in the fair value of our investment, including:

- economics of nuclear baseload generation had deteriorated substantially for reasons described above for CENG, and
- we were unable to negotiate acceptable loan guarantee terms, culminating a process that led us to reject the DOE loan guarantee due to an uneconomic level of costs.

As a result of evaluating these factors, we determined that, as of September 30, 2010, we would not be able to recover the value of our investment. Our determination was based primarily on market-related factors that indicated that a market participant would assign little or no value to this entity due to the absence of a DOE loan guarantee.

We also evaluated whether this decline in fair value was temporary. Based upon the nature of the factors leading to the decline, we determined, at September 30, 2010, that it was unlikely that these matters would be resolved in the near term in a way that would permit recovery in the fair value of our investment. Therefore, we concluded that the decline in the value of our investment in UNE was other than temporary, and we recorded a $143.4 million pre-tax impairment charge during the quarter ended September 30, 2010 to write-down our investment to estimated fair value as of that date. We recorded this charge in "Impairment losses and other costs" in our Consolidated Statements of Income (Loss).

Qualifying Facilities

As a result of the significant declines in power prices during the third quarter of 2010, we determined that the fair values of three of our equity method investments in coal-fired generating plants in California declined substantially below book value. As a result, we recorded a $50.0 million pre-tax impairment charge during the quarter ended September 30, 2010 to write down our investments to fair value as of that date.

Additionally, as a result of a sale of an ownership interest by our partner in the fourth quarter of 2010, we recorded an $8.4 million pre-tax impairment charge on one other equity method investment in California at December 31, 2010. We recorded these charges in the "Impairment losses and other costs" line in our Consolidated Statements of Income (Loss).

Generating Plants

We evaluated the impact of the events that occurred during the third quarter of 2010 on the recoverability of our generating plants. As discussed in *Note 1*, we evaluated whether these plants would generate undiscounted cash flows from operations that are at least sufficient to recover the carrying value of our investment. Based upon our consideration of these events, the primary impact of which is a reduction in power prices, and the status of the generating plants' activities, we determined that our generating plants were not impaired as of September 30, or December 31, 2010.

Goodwill

We performed our annual impairment review in the quarter ended September 30, 2010 and determined that our goodwill is not impaired.

International Coal Contract Dispute Settlement

During 2010, we finalized the settlement of a contract dispute with a third party international coal supplier recognizing net pre-tax earnings of $56.6 million. We divested the majority of our international commodities operations in 2009.

Deferred Income Tax Expense Relating to Federal Subsidies for Providing Post-Employment Prescription Drug Benefits

During March 2010, the Patient Protection and Affordable Care Act and the Healthcare and Education Reconciliation Act of 2010 were signed into law. These laws eliminate the tax exempt status of drug subsidies provided to companies under Medicare Part D after December 31, 2012. As a result of this new legislation, we recorded a noncash charge to reflect additional deferred income tax expense of $8.8 million in March 2010.

Amortization of Basis Difference in CENG

On November 6, 2009, Constellation Energy sold a 49.99% membership interest in CENG to EDF for total consideration of approximately $4.7 billion (includes $3.5 billion in cash at close, the non-cash redemption of the $1.0 billion Series B Preferred Stock held by EDF, and certain expense reimbursements). As a result, we ceased to have a controlling financial interest in CENG and deconsolidated CENG in the fourth quarter of 2009.

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On November 6, 2009, we began to account for our retained investment in CENG using the equity method and report our share of its earnings in our Generation business segment. As a result, we no longer record the individual income statement line items, but instead record our share of the investment's earnings in a single line in our Consolidated Statements of Income (Loss).

We had an initial basis difference of approximately $3.9 billion between the initial carrying value of our investment in CENG and our underlying equity in CENG. This basis difference was caused by the requirement to record our investment in CENG at fair value at closing while CENG's assets and liabilities retained their carrying value. We are amortizing this basis difference over the respective useful lives of the assets of CENG or as those assets impact the earnings of CENG.

Beginning in the fourth quarter of 2010, the amortization of the basis difference in CENG was lower as the basis difference was reduced by the amount of the impairment charge recorded on our investment in CENG during the quarter ended September 30, 2010. The new basis difference as of September 30, 2010 was $1.5 billion.

For the year ended December 31, 2010, we recorded $195.2 million of pre-tax basis difference amortization as a reduction to our equity investment earnings in CENG. We discuss the components of our equity investment earnings in *Note 4*.

Loss on Early Retirement of 2012 Notes

In February 2010, we retired an aggregate principal amount of $486.5 million of our 7.00% Notes due April 1, 2012 as part of a cash tender offer, at a premium of approximately 11%. We recognized a pre-tax loss on this transaction of $51.6 million within "Interest Expense" on our Consolidated Statements of Income (Loss).

Impact of Power Purchase Agreement with CENG

In connection with the closing of the CENG membership sale transaction with EDF, we entered into a five year power purchase agreement (PPA) with CENG with an initial fair value of $0.8 billion.

Based on energy prices at the time of closing of the EDF transaction, we recorded the approximately $0.8 billion "Unamortized energy contract asset" for the value of our PPA with CENG, and CENG recorded an approximately ($0.8) billion "Unamortized energy contract liability." Both entities are amortizing these amounts over the initial two years of the five-year term of the PPA, with the total net economic value to be realized by us in the form of lower purchased power costs equal to approximately $0.4 billion as a result of our 50.01% ownership interest in CENG. During 2010, we realized approximately $185.6 million pre-tax in economic value relating to its PPA with CENG.

Divestitures

BGE

In January 2010, BGE completed the sale of its interest in a nonregulated subsidiary that owns a district chilled water facility to a third party. BGE received net cash proceeds of $20.9 million. No gain or loss was recorded on this transaction in 2010. BGE has no further involvement in the activities of this entity.

Mammoth Lakes Geothermal Generating Facility

In August 2010, we completed the sale of our 50% equity interest in the Mammoth Lakes geothermal generating facility in California. We received net cash proceeds of approximately $72.5 million. In the third quarter of 2010, our Generation business recorded a $38.0 million pre-tax gain on this transaction. We have no further involvement in the activities of this generating facility.

Comprehensive Agreement with EDF

In November 2010, we closed on the comprehensive agreement with EDF that restructured the relationship between Constellation Energy and EDF, eliminated the outstanding asset put arrangement, and transferred to EDF the full ownership of UNE. We received approximately $140 million of cash, and $75.2 million of Constellation Energy common stock and recorded a $202.0 million pre-tax gain on this transaction. We discuss the comprehensive agreement with EDF in *Note 4*.

Quail Run Energy Center

In December 2010, we signed an agreement to sell our Quail Run Energy Center, a 550 MW natural gas plant in west Texas, to High Plains Diversified Energy Corporation (HPDEC) for $185.3 million. This agreement was contingent upon HPDEC obtaining financing through the sale of municipal bonds. This agreement was terminated in 2011.

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2009 Events

	Pre-Tax	After-Tax
	(In millions)	
Gain on sale of 49.99% membership interest in our nuclear generation and operation business (CENG) to EDF	$ 7,445.6	$ 4,456.1
Amortization of basis difference in CENG	(29.6)	(17.8)
Net loss on divestitures	(468.8)	(293.2)
Impairment losses and other costs (1)	(124.7)	(96.2)
Impairment of nuclear decommissioning trust assets through November 6, 2009	(62.6)	(46.8)
Loss on redemption of Zero Coupon Senior Notes	(16.0)	(10.0)
Maryland PSC order BGE residential customer credits	(112.4)	(67.1)
Merger termination and strategic alternatives costs	(145.8)	(13.8)
Workforce reduction costs	(12.6)	(9.3)
Total other items	$ 6,473.1	$ 3,901.9

(1) *After-tax amount net of noncontrolling interest.*

Gain on Sale of 49.99% Membership Interest in CENG to EDF

On December 17, 2008, we entered into an Investment Agreement with EDF under which EDF would purchase from us a 49.99% membership interest in CENG for $4.5 billion (subject to certain adjustments).

In October 2009, the Maryland PSC issued an order approving the sale of a 49.99% membership interest in CENG to EDF subject to the following conditions:

Constellation Energy funded a one-time $100 per customer distribution rate credit for BGE residential customers totaling $112.4 million in the fourth quarter of 2009. Constellation made a $66 million equity contribution to BGE in December 2009 to fund the after-tax amount of the rate credit as ordered by the Maryland PSC.

Constellation Energy was required to make a $250 million cash capital contribution to BGE by no later than June 30, 2010. Constellation Energy made this contribution in December 2009.

BGE will not pay common dividends to Constellation Energy if (a) after the dividend payment, BGE's equity ratio would be below 48% as calculated pursuant to the Maryland PSC's ratemaking precedents or (b) BGE's senior unsecured credit rating is rated by two of the three major credit rating agencies below investment grade.

BGE was authorized to file an electric distribution rate case at any time beginning in January 2010 and was ordered not to file a subsequent electric distribution rate case until January 2011. Any rate increase in the first electric distribution rate case was capped at 5% as agreed to by Constellation Energy in its 2008 settlement with the State of Maryland and the Maryland PSC. The timing of any gas distribution rate filing was to occur no earlier than the electric rate case.

Constellation Energy was limited to allocating no more than 31% of its holding company costs to BGE until the Maryland PSC reviews such cost allocations in the context of BGE's next rate case.

Constellation Energy and BGE implemented "ring fencing" measures in February 2010 designed to provide bankruptcy protection and credit rating separation of BGE from Constellation Energy. Such measures include the formation of a new special purpose subsidiary by Constellation Energy (RF HoldCo) to hold all of the common equity interests in BGE.

With the receipt of the Maryland PSC's order, Constellation Energy and EDF closed the transaction on November 6, 2009. Upon closing of the transaction, we sold a 49.99% membership interest in CENG to EDF for total consideration of approximately $4.7 billion (includes $3.5 billion in cash at close, the non-cash redemption of the $1.0 billion Series B Preferred Stock held by EDF, and certain expense reimbursements). As a result, we retained a 50.01% economic interest in CENG, but we and EDF have equal voting rights over the activities of

CENG. Accordingly, we deconsolidated CENG in the fourth quarter of 2009.

We recorded this transaction as follows:

We received cash consideration of approximately $3.5 billion, plus certain adjustments, and redeemed the $1.0 billion Series B Preferred Stock held by EDF as additional purchase price resulting in net proceeds of approximately $4.7 billion.

We removed the individual assets and liabilities of CENG from our balance sheet with a net asset value of approximately $2.4 billion.

We recorded our retained investment in CENG at estimated fair value of approximately $5.1 billion.

We recognized a pre-tax gain on sale of approximately $7.4 billion, calculated as follows:

	(In billions)	
Fair value of the consideration received from EDF	$	4.7
Estimated fair value of our retained interest in CENG		5.1
Carrying amount of CENG's assets and liabilities prior to deconsolidation		(2.4)
Pre-tax gain	$	7.4

On November 6, 2009, we began to account for our retained investment in CENG using the equity method and report our share of its earnings in our Generation business segment. As a result, we no longer record the individual income statement line items, but instead record our share of the investment's earnings in a single line in our Consolidated Statements of Income (Loss).

We estimated the fair value of CENG for purposes of recording our retained interest upon closing of the sale. Our estimate considered the replacement cost, discounted future cash

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flows, and comparable market transactions valuation approaches. After correlating the valuations under these three approaches, the ultimate fair value estimate reflects the discounted future expected cash flows of the business using various inputs that we believe are reflective of a market participant's perspective. The most significant inputs include our expectations of nuclear plant performance, future power prices, nuclear fuel and operating costs, forecasted capital expenditures, existing power sales commitments, and a discounting factor reflective of an investor's required risk-adjusted return.

The fair value of our investment in CENG exceeded our share of CENG's equity because CENG's assets and liabilities retained their historical carrying value. This basis difference totaled approximately $3.9 billion, and we assigned it to the noncurrent assets of CENG based on fair value. We will amortize this difference as a reduction in our equity investment earnings in CENG as follows:

Difference	**Amortization Period**
Property, plant and equipment	Depreciable life
Power purchase agreements and revenue sharing agreements	Term of the agreement
Land and intangibles with indefinite lives	Upon sale by CENG

For the period November 6, 2009 through December 31, 2009, we recorded $29.6 million of basis difference amortization as a reduction to our equity investment earnings in CENG. We discuss the components of our equity investment earnings in *Note 4*.

Also, if we were to sell an additional portion of our investment, we would recognize a proportionate amount of the basis difference.

Divestitures

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

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

- the assignment and transfer of a majority of the portfolio, and
- the execution of a Total Return Swap (TRS) mechanism for the remainder of the portfolio.

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

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

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

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

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

International Commodities Operation

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

- a pre-tax loss of approximately $334.5 million representing net consideration paid to the buyer, the book value of net assets sold, and transaction costs,
- a reclassification of $165.7 million in losses on previously designated cash-flow hedge contracts, for which the forecasted transactions are now deemed probable of not occurring, from "Accumulated Other Comprehensive Loss" to "Nonregulated revenues" in the Consolidated Statements of Income (Loss),
- workforce reduction costs of $10.9 million, recorded as part of "Workforce reduction costs" in the Consolidated Statements of Income (Loss), and
- other costs of $17.6 million related to leasehold improvements, furniture and computer hardware and software, recorded as part of "Impairment losses and other costs" in the Consolidated Statements of Income (Loss).

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

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

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

Year Ended December 31, 2009

			(In millions)
Investing activities	Contract and portfolio acquisitions	**$**	**(866.3)**
Financing activities	Proceeds from contract and portfolio acquisitions		**863.8**
Net cash flows from contract and portfolio acquisitions		**$**	**(2.5)**

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

Houston-Based Gas and Other Trading Operations

On February 3, 2009, we entered into a definitive agreement to sell our Houston-based gas trading operation. We transferred control of this operation on April 1, 2009. In addition, in the second quarter of 2009 we also sold certain other trading operations. In total, we received proceeds of approximately $61 million, and recorded a $102.5 million net loss on these sales in 2009. The net loss on sale primarily relates to nonderivative accrual contracts, which were not recorded on our Consolidated Balance Sheet, the cost associated with disposing of an entire portfolio and not merely individual contracts, and the cost of capital, including contingent capital, to support the operation.

The matching derivative and nonderivative transactions under the TRS discussed above were executed at prices that differed from market prices at closing. As a result, we record the ongoing cash flows related to the out-of-the-money derivative contracts that were liabilities at inception as financing cash flows. This resulted in cash outflows related to financing activities of $858.5 million in our Consolidated Statements of Cash Flows for the year ended December 31, 2009 associated with derivative liabilities that were out-of-the-money.

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

Year Ended December 31, 2009

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

In addition, we incurred other costs of $7.0 million for 2009 related to leasehold improvements, furniture, computer hardware and software costs, which are recorded as part of "Impairment losses and other costs" on our Consolidated Statements of Income (Loss).

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

Shipping Joint Venture

We completed the sale of our equity investment in a shipping joint venture during the third quarter of 2009. No gain or loss was recognized on the sale. We discuss the sale of the shipping joint venture below.

Other Nonregulated Divestiture

During the fourth quarter of 2009, one of our nonregulated subsidiaries sold an energy project and recorded a net loss of $4.6 million.

Impairment Losses and Other Costs

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 indicate the potential for an impairment exists.

Available for Sale Securities

We evaluated certain of our investments in equity securities during 2009. The investments we evaluated included our nuclear decommissioning trust fund assets (through November 6, 2009) and other marketable securities. We record an impairment charge if an investment has experienced a decline in fair value to a level

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less than our carrying value and the decline is "other than temporary."

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

The fair values of certain of the securities held in our nuclear decommissioning trust fund held through November 6, 2009 and other marketable securities declined below book value. As a result, we recorded a $62.6 million pre-tax impairment charge for the year ended December 31, 2009 for our nuclear decommissioning trust fund assets in the "Other income (expense)" line in our Consolidated Statements of Income (Loss). We also recorded an impairment charge of $0.5 million for other marketable securities not included in our nuclear decommissioning trust funds for the year ended December 31, 2009.

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

Equity Method Investments

Shipping Joint Venture

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

As a result of the events that occurred during the second quarter of 2009, we concluded that the fair value of our investment had declined to a level below the carrying value at June 30, 2009 and that this decline was other than temporary. As such, we recorded a pre-tax impairment charge of $59.0 million associated with our equity investment in our shipping joint venture within the "Impairment losses and other costs" line in our Consolidated Statements of Income (Loss), and reported the charge in our NewEnergy business segment results for 2009.

Constellation Energy Partners LLC

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

The decline in fair value of our investment in CEP at that time reflected a number of factors, primarily including difficulties in the financial and credit markets and the decreases in the market price of natural gas and oil.

As a result of evaluating these factors, we determined that the decline in the value of our investment is other than temporary. Therefore, we recorded a $14.0 million pre-tax impairment charge at March 31, 2009 to write-down our investment to fair value. We recorded this charge in "Impairment losses and other costs" in our Consolidated Statements of Income (Loss). We did not record an impairment charge for the remainder of 2009.

District Chilled Water

During 2009, BGE entered into an agreement to sell its interest in a nonregulated subsidiary that owns a district chilled water facility to a third party. We completed this sale in January 2010. We have no further involvement in the activities of this entity.

As a result of these events, we concluded that the fair value of our investment in this subsidiary had declined to a level below carrying value at December 31, 2009 and that this decline was other than temporary. As such, we recorded a pre-tax impairment charge of $12.0 million, net of the noncontrolling interest impact of $8.0 million. The gross impairment charge of $20.0 million is recorded within the "Impairment losses and other costs" line in both our and BGE's Consolidated Statements of Income (Loss). The noncontrolling interest portion of $8.0 million is recorded within the "Net Income Attributable to Noncontrolling Interests and BGE Preference Stock Dividends" line in our Consolidated Statements of Income (Loss) and within the "Net Income Attributable to Noncontrolling Interests" line in BGE's Consolidated Statements of Income.

Other Costs

During 2009, we recorded $31.2 million pre-tax charges in the "Impairment losses and other costs" line in our Consolidated Statements of Income (Loss) primarily related to:

- divested operations long-lived assets no longer used and lease terminations, and
- the write-off of an uncollectible advance to an affiliate.

Loss on Redemption of Zero Coupon Senior Notes

In November 2009, we redeemed the Zero Coupon Senior Notes early and recognized a pre-tax loss on redemption of $16.0 million within "Interest Expense" on our Consolidated Statements of Income (Loss).

Merger Termination and Strategic Alternatives Costs

We incurred additional costs during 2009 related to the terminated merger agreement with MidAmerican, the transactions related to EDF, and other strategic alternatives costs. These costs totaled $145.8 million pre-tax for the year ended December 31, 2009, and primarily relate to fees incurred to complete the transactions with EDF and the first quarter of 2009 write-off of the unamortized debt discount associated with the 14% Senior Notes (Senior Notes) that were repaid in full to MidAmerican in January 2009. Upon the closing of the transaction with EDF on November 6, 2009, certain of the costs

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incurred in 2008 and 2009 became tax deductible. We reflected this impact in 2009.

Workforce Reduction Costs

We incurred workforce reduction costs during the fourth quarter of 2008, primarily related to workforce reduction efforts across all of our operations (Q4 2008 Program), and during the first quarter of 2009, primarily related to the divestiture of a majority of our international commodities operation as well as some smaller restructurings elsewhere in our organization (Q1 2009 Program). For the Q1 2009 Program, we recognized a $12.6 million pre-tax charge during 2009 related to the elimination of approximately 180 positions. We substantially completed these workforce reductions during 2010.

The following table summarizes the status of the involuntary severance liabilities at December 31, 2009:

	Q1 2009 Program	Q4 2008 Program
	(In millions)	
Initial severance liability balance	$ 10.8	$ 19.7
Additional expenses recorded in 2009	1.8	
Amounts recorded as pension and postretirement liabilities		(3.0)
Net cash severance liability	12.6	16.7
Cash severance payments	(12.0)	(15.8)
Severance liability balance at December 31, 2009	$ 0.6	$ 0.9

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3 Information by Operating Segment

Our reportable operating segments are Generation, NewEnergy, Regulated Electric, and Regulated Gas:

- Our Generation business includes:
  - a power generation and development operation that owns, operates and maintains fossil and renewable generating facilities, a fuel processing facility, qualifying facilities, and power projects in the United States,
  - an operation that manages certain contractually controlled physical assets, including generating facilities, and
  - an interest in a nuclear generation joint venture (CENG) that owns, operates, and maintains five nuclear generating units.
- Our NewEnergy business includes:
  - full requirements load-serving sales of energy and capacity to utilities, cooperatives, and commercial, industrial, and governmental customers,
  - sales of retail energy products and services to residential, commercial, industrial, and governmental customers,
  - structured transactions and risk management services for various customers (including hedging of output from generating facilities and fuel costs) and trading in energy and energy-related commodities to facilitate portfolio management,
  - risk management services for our Generation business,
  - design, construction, and operation of renewable energy, heating, cooling, and cogeneration facilities for commercial, industrial, and governmental customers throughout North America, including energy performance contracting and energy efficiency engineering services,
  - upstream (exploration and production) natural gas activities, and
  - sales of home improvements, servicing of electric and gas appliances, and heating, air conditioning, plumbing, electrical, and indoor air quality systems, and providing electric and natural gas to residential customers in central Maryland.
- Our regulated electric business purchases, transmits, distributes, and sells electricity in central Maryland.
- Our regulated gas business purchases, transports, and sells natural gas in central Maryland.

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

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	Reportable Segments				Holding Company and Other		
	Generation	NewEnergy	Regulated Electric	Regulated Gas	Holding Company and Other	Eliminations	Consolidated
				(In millions)			
2011							
Unaffiliated revenues	$ 1,122.3	$ 9,649.0	$ 2,320.7	$ 664.5	$ 1.7	$	$ 13,758.2
Intersegment revenues	1,595.4	471.2	0.7	7.2		(2,074.5)	
Total revenues	2,717.7	10,120.2	2,321.4	671.7	1.7	(2,074.5)	13,758.2
Depreciation, depletion, accretion, and amortization	187.4	89.4	226.5	45.6	40.4		589.3
Fixed charges	128.8	9.4	103.4	23.2	0.1	0.5	265.4
Income tax (benefit) expense	(300.7)	(8.8)	50.1	23.4	5.1		(230.9)
Net (loss) income (1)	(441.1)	2.8	93.6	42.1	(4.2)		(306.8)
Net (loss) income attributable to common stock	(441.1)	(17.5)	83.8	38.7	(4.2)		(340.3)
Segment assets	8,738.6	4,136.1	5,506.7	1,480.3	854.2	(1,303.3)	19,412.6
Capital expenditures	159.7	322.9	535.4	142.5			1,160.5
2010							
Unaffiliated revenues	$ 1,189.2	$ 9,692.6	$ 2,752.1	$ 704.9	$ 1.2	$	$ 14,340.0
Intersegment revenues	1,055.1	428.8	0.2	4.5		(1,488.6)	
Total revenues	2,244.3	10,121.4	2,752.3	709.4	1.2	(1,488.6)	14,340.0
Depreciation, depletion, accretion, and amortization	137.7	83.7	205.2	44.0	48.9		519.5
Fixed charges	142.0	3.0	106.3	24.0	(0.2)	2.7	277.8
Income tax (benefit) expense	(873.1)	106.5	72.6	24.5	3.8		(665.7)
Net (loss) income (2)	(1,255.3)	176.2	110.0	37.6	(0.3)		(931.8)
Net (loss) income attributable to common stock	(1,255.3)	138.6	99.8	34.6	(0.3)		(982.6)
Segment assets	9,789.6	3,836.2	5,287.4	1,379.9	858.0	(1,132.6)	20,018.5
Capital expenditures	327.4	127.2	499.1	103.0			1,056.7
2009							
Unaffiliated revenues	$ 664.2	$ 11,345.8	$ 2,820.7	$ 753.8	$ 14.3	$	$ 15,598.8
Intersegment revenues	2,110.0	163.4		4.5	0.1	(2,278.0)	
Total revenues	2,774.2	11,509.2	2,820.7	758.3	14.4	(2,278.0)	15,598.8
Depreciation, depletion, accretion, and amortization	238.9	82.7	218.1	44.0	67.7		651.4
Fixed charges	166.5	39.7	113.3	26.0	2.4	2.2	350.1
Income tax expense (benefit)	3,107.1	(179.1)	50.9	17.1	(9.2)		2,986.8
Net income (loss) (3)	4,766.7	(348.2)	79.1	25.5	(19.7)		4,503.4
Net income (loss) attributable to common stock	4,766.7	(402.3)	68.9	22.5	(12.4)		4,443.4
Segment assets	12,402.1	4,167.5	4,994.6	1,413.4	4,573.7	(4,006.9)	23,544.4
Capital expenditures	1,039.2	116.8	373.0	66.0			1,595.0

(1) *Our Generation business recognized the following after-tax items: impairment losses and other costs of $530.2 million, amortization of the basis difference in CENG of $90.5 million, impact of the power purchase agreement with CENG of $118.5 million, gain on settlements with DOE for storage of spent nuclear fuel of $57.3 million, transaction fees incurred related to our acquisition of Boston Generating's 2,950 MW fleet of generating plants in Massachusetts of $9.9 million, and costs incurred related to our pending merger with Exelon of $37.0 million. Our NewEnergy business recognized a gain on divestitures of $32.7 million, amortization of credit facility amendment fees in connection with the 2009 EDF transaction of $5.8 million, and costs incurred related to our pending merger with Exelon of $16.1 million. Our Regulated Electric and Gas businesses recognized costs incurred related to our pending merger with Exelon of $13.3 million and $4.5 million, respectively. BGE will not seek recovery of these costs in rates. In addition, our regulated electric business incurred total incremental operating expenses of $24.6 million related to Hurricane Irene.*

(2) *Our Generation business recognized the following after-tax items: impairment charges on certain of our equity method investment of $1,487.1 million, loss on the early retirement of 2012 Notes of $30.9 million, amortization of the basis difference in CENG of $117.5 million, impact of the power purchase agreement with CENG of $113.3 million, gain on the sale of Mammoth Lakes geothermal generating facility of $24.7 million, and a gain on*

the comprehensive agreement with EDF of $121.3 million. Our NewEnergy business recognized earnings relating to an international coal supplier contract dispute settlement of $35.4 million. Our Generation, NewEnergy, regulated electric and holding company and other businesses recognized deferred income tax expense relating to federal subsidies for providing post-employment prescription drug benefits of $0.8 million, $0.1 million, $3.1 million, and $4.8 million, respectively. We discuss these items in more detail in Note 2.

(3)

Our Generation business recognized the following after-tax items: gain on sale of a 49.99% membership interest in CENG to EDF of $4,456.1 million, amortization of basis difference in investment in CENG of $17.8 million, loss on the early extinguishment of zero coupon senior notes of $10.0 million, merger termination and strategic alternatives costs of $9.7 million, and impairment charges of our nuclear decommissioning trust assets through November 6, 2009 of $46.8 million. Our NewEnergy business recognized the following after-tax items: merger termination and strategic alternatives costs of $4.1 million, losses on divestitures, which include losses on the sales of the international commodities and gas trading operations, the reclassification of losses on previously designated cash-flow hedges from Accumulated Other Comprehensive Loss because the forecasted transactions are probable of not occurring, earnings that are no longer part of our core business, of $371.9 million, impairment losses and other costs of $84.7 million, and workforce reduction costs of $9.3 million. Our regulated electric and gas businesses recognized after-tax charges of $56.7 million and $10.4 million, respectively, for the accrual of a residential customer credit. Our holding company and other businesses recognized after-tax charges of $11.5 million for impairment losses and other costs. We discuss these items in more detail in Note 2.

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4 Investments

Investments in Joint Ventures, Qualifying Facilities and Power Projects

Investments in joint ventures, qualifying facilities, and domestic power projects consist of the following:

At December 31,	2011	2010
	(In millions)	
CENG Joint Venture	**$ 2,150.4**	$ 2,991.1
Qualifying facilities and domestic power projects:		
Coal	**33.4**	65.0
Hydroelectric	**43.0**	46.3
Biomass	**24.6**	55.1
Fuel Processing	**21.4**	16.7
Solar		6.8
Total	**$ 2,272.8**	$ 3,181.0

Investments in joint ventures, qualifying facilities, domestic power projects, and CEP were accounted for under the following methods:

At December 31,	2011	2010
	(In millions)	
Equity method	**$ 2,272.8**	$ 3,174.2
Cost method		6.8
Total	**$ 2,272.8**	$ 3,181.0

We recorded impairment charges on certain of our equity and cost method investments. We discuss these impairment charges in *Note 2*.

We are actively involved in our CENG nuclear joint venture, qualifying facilities and power projects. Our percentage voting interests in these investments accounted for under the equity method range from 20% to 50.01%. Equity in earnings of these investments is as follows:

Year ended December 31,	2011	2010	2009
		(In millions)	
CENG	**$ 148.8**	$ 218.8	$ 33.9
Amortization of basis difference in CENG (see *Note 2* for more detail)	**(153.1)**	(195.2)	(29.6)
Total equity investment earnings CENG (1)	**(4.3)**	23.6	4.3
UNE		(16.8)	(24.7)
Shipping JV			(1.8)
CEP			(4.6)
Qualifying facilities and domestic power projects	**24.1**	18.2	20.7
Total equity investment earnings	**$ 19.8**	$ 25.0	$ (6.1)

(1) *For the years ended December 31, 2011, 2010, and 2009 total equity investment (losses) earnings in CENG include $1.1 million, $2.0 million, and $0.4 million, respectively, of expense related to the portion of cost of certain share-based awards that we fund on behalf of EDF.*

We describe each of these investments below.

Joint Ventures

CENG

On November 6, 2009, we completed the sale of a 49.99% membership interest in CENG, our nuclear generation and operation business, to EDF. As a result of this transaction, we deconsolidated CENG and began to record our 50.01% investment in CENG under the equity method of accounting. Because the transaction occurred on November 6, 2009, we recorded $4.3 million of equity investment earnings in CENG, which represents our share of earnings from CENG from November 6, 2009 through December 31, 2009, net of the amortization of the basis difference in CENG. The basis difference is the difference between the fair value of our investment in CENG at closing and our share of the underlying equity in CENG, because the underlying assets and liabilities of CENG were retained at their carrying value. See *Note 2* for a more detailed discussion.

Summarized balance sheet information for CENG is as follows:

At December 31,	**2011**	**2010**
	(In millions)	
Current assets	**$ 415.6**	$ 507.4
Noncurrent assets	**4,710.6**	4,583.0
Current liabilities	**273.1**	630.9
Noncurrent liabilities	**1,459.1**	1,338.7

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Summarized income statement information for CENG is as follows:

	For the Year Ended December 31, 2011	For the Year Ended December 31, 2010	For the Period from November 6, 2009 through December 31, 2009
		(In millions)	
Revenues	**$ 1,516.3**	$ 1,575.3	$ 217.6
Expenses	**1,248.9**	1,174.5	153.0
Income from operations	**267.4**	400.8	64.6
Net income	**299.8**	441.6	68.5

In future periods, we may be eligible for distributions from CENG in excess of our 50.01% ownership interest based on tax sharing provisions contained in the operating agreement for CENG. We would record these distributions, if realized, in earnings in the period received.

Comprehensive Agreement with EDF

On October 26, 2010, we reached a comprehensive agreement with EDF that restructured the relationship between our two companies, eliminated the outstanding asset put arrangement, and transferred to EDF the full ownership of UNE. This comprehensive agreement was approved by the boards of directors of both Constellation Energy and EDF, and the transaction closed on November 3, 2010. The agreement includes the following significant terms:

- EDF acquired our 50% ownership interest in UNE. Upon completion of this transaction, EDF became the sole owner of UNE, and we no longer have responsibility for developing or financing new nuclear plants through UNE.
- We terminated our rights under the existing asset put arrangement and, as a result, did not sell any of our plants to EDF.
- EDF paid us $140 million in cash and transferred to us 2.4 million of the shares of Constellation Energy common stock that it owned (with a fair value of $72.4 million at the time of the noncash financing transfer).
- EDF relinquished its seat on our Board of Directors, and the existing investor agreement between the companies (which includes a "standstill" provision) was terminated.

Later in November 2010, EDF transferred to us 0.1 million shares of Constellation Energy common stock, with a fair value of $2.8 million, in a noncash financing, upon our registering EDF's remaining shares of Constellation Energy common stock with the Securities and Exchange Commission. This enables EDF to transfer its remaining shares without restriction. We recorded a total pre-tax gain of $202.0 million in the fourth quarter of 2010 related to the above aspects of our comprehensive agreement with EDF.

In addition, upon receipt of necessary approvals:

- CENG will transfer to UNE potential new nuclear sites at the Nine Mile Point and Ginna nuclear generating plants in New York State.
- EDF will transfer to us an additional 1.0 million of the shares of Constellation Energy common stock that it owns.

EDF may release us from our obligation to transfer the potential new nuclear sites and retain the shares if we have not certified to EDF that we have the legal right to transfer the sites by May 2012 or if we do not transfer the sites to UNE by early November 2012.

We and EDF will remain owners in CENG under the same ownership percentages Constellation Energy holding a 50.01% interest and EDF holding a 49.99% interest. Further:

The power purchase agreement between CENG and each of Constellation Energy and EDF was modified such that prospective purchases will be unit contingent through the end of its term in 2014. In addition, beginning on January 1, 2015 and continuing to the end of the life of the respective plants, we will purchase 50.01% of the output of CENG's nuclear plants and EDF will purchase 49.99% of that output.

The administrative services agreement, which specifies payment to us for providing administrative support services to CENG, was extended through 2017.

We discuss the PPA and ASA in more detail in *Note 16*.

UNE

In August 2007, we formed a joint venture, UNE, with EDF to develop, own, and operate new nuclear projects in the United States and Canada. On November 3, 2010, we sold our 50% ownership interest in UNE to EDF. As a result of this transaction, EDF is the sole owner of UNE, and we will no longer have responsibility for developing or financing new nuclear plants through UNE.

Qualifying Facilities and Power Projects

Our Generation business holds up to a 50% voting interest in 15 operating domestic energy projects that consist of electric generation, fuel processing, or fuel handling facilities. Of these 15 projects, 13 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 2011, we sold substantially all of our interests in Constellation Energy Partners LLC (CEP) to PostRock Energy Corporation (PostRock). However, we did retain certain non-voting interests in CEP. Since we no longer have significant influence over CEP's activities following the sale, these retained interests do not qualify for the equity method of accounting. We discuss this transaction in more detail in *Note 2*.

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Investments in Variable Interest Entities

As of December 31, 2011, we consolidated four VIEs in which we were the primary beneficiary, and we had significant interests in six other VIEs for which we do not have controlling financial interests and, accordingly, were not the primary beneficiary.

Consolidated Variable Interest Entities

The carrying amounts and classification of the above consolidated VIEs' assets and liabilities included in our consolidated financial statements at December 31, 2011 and 2010 are as follows:

	2011	2010
	(In millions)	
Current assets	**$ 481.5**	$ 516.6
Noncurrent assets	**348.6**	57.7
Total Assets	**$ 830.1**	$ 574.3
Current liabilities	**$ 483.4**	$ 345.5
Noncurrent liabilities	**540.0**	399.0
Total Liabilities	**$ 1,023.4**	$ 744.5

All of the assets in the table above are restricted for settlement of the VIE obligations and all of the liabilities in the preceding table can only be settled using VIE resources with the exception of $130.0 million of debt relating to a group of solar entities formed by us, which is recourse to us.

RSB BondCo LLC

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

The BondCo assets are restricted and can only be used to settle the obligations of BondCo. Further, BGE is required to remit all payments it receives from customers for rate stabilization charges to BondCo. During 2011, 2010, and 2009, BGE remitted $92.3 million, $90.3 million, and $85.8 million, respectively, to BondCo.

BGE did not provide any additional financial support to BondCo during 2011 or 2010. Further, BGE does not have any contractual commitments or obligations to provide additional financial support to BondCo unless additional rate stabilization bonds are issued. The BondCo creditors do not have any recourse to the general credit of BGE in the event the rate stabilization charges are not sufficient to cover the bond principal and interest payments of BondCo.

Retail Gas Group

During 2009, our NewEnergy business formed two new entities and combined them with its existing retail gas activities into a retail gas entity group for the purpose of entering into a collateralized gas supply agreement with a third party gas supplier. While we own 100% of these entities, we determined that the retail gas entity group is a VIE because there is not sufficient equity to fund the group's activities without the additional credit support we provide in the form of a parental guarantee. We are the primary beneficiary of the retail gas entity group; accordingly, we consolidate the retail gas entity group as a VIE, including the existing retail gas customer supply operation, which we formerly consolidated as a voting interest entity.

The gas supply arrangement is collateralized as follows:

The assets of the retail gas entity group must be used to settle obligations under the third party gas supply agreement before it can make any distributions to us,

The third party gas supplier has a collateral interest in all of the assets and equity of the retail gas entity group, and

As of December 31, 2011, we provided a $75 million parental guarantee to the third party gas supplier in support of the retail gas entity group.

Other than credit support provided by the parental guarantee, we do not have any contractual or other obligations to provide additional financial support to the retail gas entity group. The retail gas entity group creditors do not have any recourse to our general credit. Finally, we did not provide any financial support to the retail gas entity group during 2011, other than the equity contributions and parental guarantee.

Retail Power Supply Entity

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

Solar Project Entity Group

In 2011, we formed a group of solar project limited liability companies to build, own, and operate solar power facilities. While we own 100% of these entities, we determined that the individual solar project entities are VIEs because either the entities require additional subordinated financial support in the form of parental guarantee of debt, loans from the customers in order to obtain the necessary funds for construction of the solar facilities, or the customers absorb price variability from the entities through the fixed price power and/or renewable energy credits purchase agreements. We are the primary beneficiary of the solar project entities because we control the design, construction, and operation of the solar power facilities. We provide capital funding to this solar group for ongoing construction of the solar power facilities as well as a $150 million credit facility.

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RF HoldCo LLC

During 2010, as part of the 2009 order from the Maryland PSC approving our transaction with EDF, we created RF HoldCo LLC, a bankruptcy-remote special purpose subsidiary to hold all of the common equity interests in BGE. This subsidiary is not a VIE. However, due to our ownership of 100% of the voting interests of RF HoldCo LLC, we consolidate this subsidiary as a voting interest entity.

BGE and RF HoldCo are separate legal entities and are not liable for the debts of Constellation Energy. Accordingly, creditors of Constellation Energy may not satisfy their debts from the assets of BGE and RF HoldCo except as required by applicable law or regulation. Similarly, Constellation Energy is not liable for the debts of BGE or RF HoldCo. Accordingly, creditors of BGE and RF HoldCo may not satisfy their debts from the assets of Constellation Energy except as required by applicable law or regulation.

Unconsolidated Variable Interest Entities

As of December 31, 2011 and 2010, we had significant interests in six VIEs for which we were not the primary beneficiary. We have not provided any material financial or other support to these entities during 2011 and 2010 and we do not intend to provide any additional financial or other support to these entities in the future.

The following is summary information available as of December 31, 2011 about these entities:

	Power Contract Monetization VIEs	All Other Power Project VIEs	Total
		(In millions)	
Total assets	$ 386.5	$ 309.6	$ 696.1
Total liabilities	303.9	106.4	410.3
Our ownership interest		53.5	53.5
Other ownership interests	82.6	149.7	232.3
Our maximum exposure to loss:			
Letters of credit	15.5		15.5
Carrying amount of our investment Other investments		39.8	39.8
Debt and payment guarantees		5.0	5.0

The following is summary information available as of December 31, 2010 about these entities:

	Power Contract Monetization VIEs	All Other VIEs	Total
		(In millions)	
Total assets	$ 492.9	$ 288.3	$ 781.2
Total liabilities	382.6	113.2	495.8
Our ownership interest		48.7	48.7
Other ownership interests	110.3	126.4	236.7
Our maximum exposure to loss:			
Letters of credit	24.9		24.9
Carrying amount of our investment Other investments		41.4	41.4
Debt and payment guarantees		5.0	5.0

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 NewEnergy 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.

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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, 2011 and 2010, our goodwill balance was primarily related to our retail energy reporting unit within our NewEnergy business segment. Goodwill is not amortized; rather, it is evaluated for impairment at least annually.

The changes in the gross amount of goodwill and the accumulated impairment losses for the years ended December 31, 2011 and 2010 are as follows:

At December 31,	2011	2010
	(In millions)	
Balance as of January 1,		
Gross goodwill	**$ 343.5**	$ 292.0
Accumulated impairment losses	**(266.5)**	(266.5)
Net goodwill	**77.0**	25.5
Goodwill acquired (1)	**202.4**	51.5
Impairment losses		
Other purchase price adjustments	**2.8**	
Balance as of December 31,		
Gross goodwill	**548.7**	343.5
Accumulated impairment losses	**(266.5)**	(266.5)
Net goodwill	**$ 282.2**	$ 77.0

(1)
We discuss the goodwill acquired in 2011 and 2010 in more detail in Note 15.

For tax purposes, $154.0 million of our gross goodwill balance at December 31, 2011 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,	2011			2010		
	Gross Carrying Amount	Accumulated Amortization	Net Asset	Gross Carrying Amount	Accumulated Amortization	Net Asset
			(In millions)			
Software	**$ 478.6**	**$ (322.7)**	**$ 155.9**	$ 596.8	$ (397.1)	$ 199.7
Permits and licenses	**4.5**	**(1.6)**	**2.9**	2.7	(1.0)	1.7
Other	**233.3**	**(89.6)**	**143.7**	22.3	(8.2)	14.1
Total	**$ 716.4**	**$ (413.9)**	**$ 302.5**	$ 621.8	$ (406.3)	$ 215.5

BGE had intangible assets with a gross carrying amount of $140.2 million and accumulated amortization of $76.8 million at December 31, 2011 and $250.2 million and accumulated amortization of $171.4 million at December 31, 2010 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,	**2011**	2010	2009
		(In millions)	
Nonregulated businesses	**$ 87.8**	$ 64.8	$ 74.2
BGE	**25.4**	25.8	23.6
Total Constellation Energy	**$ 113.2**	$ 90.6	$ 97.8

The following is our, and BGE's, estimated amortization expense related to our intangible assets for 2012 through 2016 for the intangible assets included in our, and BGE's, Consolidated Balance Sheets at December 31, 2011:

Year Ended December 31,		2012	2013	2014	2015	2016
				(In millions)		
Estimated amortization expense	Nonregulated businesses	$ 82.8	$ 62.1	$ 40.9	$ 22.4	$ 14.0
Estimated amortization expense	BGE	20.7	16.3	10.3	6.9	1.7
Total estimated amortization expense	Constellation Energy	$ 103.5	$ 78.4	$ 51.2	$ 29.3	$ 15.7

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. Unamortized energy contract assets also include the power purchase agreement entered into with CENG with an initial fair value of approximately $0.8 billion. See *Note 16* for more details on this power purchase agreement.

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	**2011**			2010		
	Carrying Amount	**Accumul-ated Amortiz-ation**	**Net (Liability) Asset**	Carrying Amount	Accumul-ated Amortiz-ation	Net Asset
				(In millions)		
Unamortized energy contracts, net	**$ (1,454.9)**	**$ 1,152.5**	**$ (302.4)**	$ (1,360.9)	$ 1,473.8	$ 112.9

We recognized amortization expense (income) of $395.4 million, $106.8 million, and ($353.1) million related to these energy contract assets for the years ended December 31, 2011, 2010, and 2009 for our nonregulated businesses.

The table below presents the estimated amortization for these assets and liabilities over the next five-years:

Year Ended December 31,	2012	2013	2014	2015	2016
			(In millions)		

Estimated amortization expense (income)	$	(65.2)	$	(81.2)	$	(71.3)	$	(65.6)	$	(16.4)

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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,	**2011**	**2010**
	(In millions)	
Deferred fuel costs		
Rate stabilization deferral	**$ 358.3**	$ 415.6
Other	**61.0**	8.8
Electric generation-related regulatory asset	**71.4**	86.9
Net cost of removal	**(218.2)**	(210.5)
Income taxes recoverable through future rates (net)	**71.4**	68.3
Deferred BGE Smart Energy Savers Program® costs	**123.5**	64.3
Deferred Advanced Meter Infrastructure costs	**15.4**	12.2
Deferred storm costs	**12.4**	
Deferred postretirement and postemployment benefit costs	**5.2**	6.4
Deferred environmental costs	**3.1**	5.6
Workforce reduction costs	**1.1**	1.3
Other (net)	**(9.0)**	(6.1)
Total regulatory assets (net)	**495.6**	452.8
Less: Current portion of regulatory assets (net)	**153.7**	78.7
Long-term portion of regulatory assets (net)	**$ 341.9**	$ 374.1

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 2011 and 2010, BGE recovered $57.2 million and $61.8 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 repaid the deferred charges without interest over a 21-month period which began in April 2008 and ended 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 other 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 accounting for a regulated business for the previous electric generation portion of its business. As a result, BGE wrote-off its entire individual, generation-related regulatory assets and liabilities. BGE established a single, generation-related regulatory asset to be collected through its regulated rates, 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 $56.0 million as of December 31, 2011 and $53.3 million as of December 31, 2010. We will continue to amortize this amount through 2017.

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, the recognition of expected net future costs of removal is shown 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 BGE Smart Energy Savers Program® Costs

Deferred BGE Smart Energy Savers Program® costs are the costs incurred to implement demand response and conservation programs. These programs are designed to help BGE manage peak demand, improve system reliability, reduce customer consumption, and improve service to customers by giving customers greater control over their energy use. Actual marketing and customer bonus costs incurred in the demand response program, which began in January 2008, are being recovered over a 5-year amortization period from the date incurred pursuant to an order by the Maryland PSC. Fixed assets are recovered over the life of the equipment. Actual costs incurred in the conservation program are being amortized over a 5-year period with recovery beginning in 2010 pursuant to an order by the Maryland PSC.

Deferred Advanced Meter Infrastructure Costs

Between 2007 and 2009, the Maryland PSC approved and BGE conducted a series of successful smart grid pilot programs for a total cost of $11.3 million, which, pursuant to a Maryland PSC order, was deferred in a regulatory asset, and, beginning with the Maryland PSC's March 2011 rate order, is earning a regulated rate of return. In August 2010, the Maryland PSC approved a comprehensive smart grid initiative for BGE that included the planned installation of 2 million residential and commercial electric and gas smart meters and modules. As part of the Maryland PSC's August 2010 order, BGE has been authorized to establish a separate regulatory asset for incremental costs incurred to implement the initiative, net depreciation and amortization associated with the meters, and an appropriate return on these costs. Additionally, the Maryland PSC order requires that BGE prove the cost-effectiveness of the entire smart grid initiative prior to seeking recovery of the costs deferred in these regulatory assets. Therefore, the commencement and timing of the amortization of these deferred costs is currently unknown.

Deferred Storm Costs

In the Maryland PSC's March 2011 rate order, BGE was authorized to defer as a regulatory asset $15.8 million in storm costs incurred in February 2010. These costs are being amortized over a 5-year period that began in December 2010.

Deferred Postretirement and Postemployment Benefit Costs

We record a regulatory asset for the deferred postretirement and postemployment benefit costs 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 $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 received rate relief for an additional $5.4 million of clean-up costs incurred during the period from July 2000 through November 2005 and an additional $1.0 million from December 2005 through November 2010. These costs are being amortized over a 10-year periods that began in January 2006 and December 2010, respectively.

Workforce Reduction Costs

The portion of the costs associated with our 2008 workforce reduction program that relate to BGE's gas business were deferred in 2009 as a regulatory asset in accordance with the Maryland PSC's orders in prior rate cases and are being amortized over a 5-year period that began in January 2009. Costs associated with a 2010 workforce reduction were deferred as a regulatory asset and are being amortized over a 5-year period that began in March 2011 in accordance with the Maryland PSC's March 2011 rate order.

Other (Net)

Other regulatory assets are comprised of a variety of current assets and liabilities that primarily do not earn a regulatory rate of return due to their short-term nature.

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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, owned by CENG, offers its own pension, postretirement, other postemployment, and employee savings plan benefits to its employees. In connection with the deconsolidation of CENG as a result of the investment in CENG by EDF on November 6, 2009, the Nine Mile Point plan is no longer included in our consolidated results. In addition, benefit plan assets and obligations relating to CENG employees that previously participated in our plans were transferred into new CENG plans that are no longer included in our consolidated results. Therefore, the tables below include the benefits for the CENG plans, including Nine Mile Point, through November 6, 2009. In 2011, we acquired certain Boston Generating plants. As a result, the benefit plan assets and obligations relating to Boston Generating employees are included in our consolidated results and 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,	**2011**	2010
	(In millions)	
Pension benefits	**$ 327.8**	$ 218.0
Postretirement benefits	**347.8**	334.9
Postemployment benefits	**53.1**	55.0
Total defined benefit obligations	**728.7**	607.9
Less: Amount recorded in other current liabilities	**30.7**	33.2
Total noncurrent defined benefit obligations	**$ 698.0**	$ 574.7

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 plan by contributing at least the minimum amount required under IRS regulations. We calculate the amount of funding using an actuarial method called the traditional unit credit method.

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 2011 Accumulated Postretirement Benefit Obligation by

$30.3 million and our 2011 postretirement medical payments by $3.1 million.

Liability Adjustments

At December 31, 2011 and 2010, our pension obligations and the fair value of our plan assets for our qualified and our nonqualified pension plans were as follows:

	Qualified Plans		Non-	
At December 31, 2011	**Constellation Energy**	**Boston Generating**	**Qualified Plans**	**Total**
Accumulated benefit obligation	**$ 1,567.0**	**$ 3.2**	**$ 101.8**	**$ 1,672.0**
Fair value of assets	**1,484.3**	**3.4**		**1,487.7**
Net (asset) unfunded obligation	**$ 82.7**	**$ (0.2)**	**$ 101.8**	**$ 184.3**

At December 31, 2010	**Qualified Plan**	**Non-Qualified Plans**	**Total**
		(In millions)	
Accumulated benefit obligation	**$ 1,405.2**	**$ 87.8**	**$ 1,493.0**
Fair value of assets	**1,408.1**		**1,408.1**
Net (asset) unfunded obligation	**$ (2.9)**	**$ 87.8**	**$ 84.9**

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. We reflect the funded status of our

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postretirement benefits in terms of the accumulated postretirement benefit obligation.

The following table summarizes the impacts of funded status adjustments recorded during 2011 and 2010:

	Pension Liability	Postretirement Benefit Liability	Accumulated Other Comprehensive Income (Loss) Pre-tax	Accumulated Other Comprehensive Income (Loss) After-tax
		(In millions)		
December 31, 2011	**$ 167.2**	**$ 8.0**	**$ (175.2)**	**$ (106.4)**
December 31, 2010	$ 73.7	$ 10.9	$ (84.6)	$ (54.6)

Obligations and Assets

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 2011	Pension Benefits 2010	Postretirement Benefits 2011	Postretirement Benefits 2010
		(In millions)		
Change in benefit obligation (1)				
Benefit obligation at January 1	**$ 1,626.1**	$ 1,469.8	**$ 334.9**	$ 322.3
Service cost	**50.3**	37.9	**2.9**	2.4
Interest cost	**87.4**	84.7	**17.1**	17.7
Plan amendments	**(0.5)**		**1.3**	(3.3)
Plan participants' contributions			**9.7**	10.5
Actuarial loss	**146.2**	124.0	**6.7**	14.2
Acquisition of Boston Generating plan	**3.2**			
Separation of CENG plans		(3.0)		
Settlements	**(6.0)**	(5.2)		
Special termination benefits		0.6	**0.2**	0.1
Benefits paid (2)(3)	**(91.2)**	(82.7)	**(25.0)**	(29.0)
Benefit obligation at December 31	**$ 1,815.5**	$ 1,626.1	**$ 347.8**	$ 334.9

(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 and Early Retiree Reimbursement Program reimbursements.*

	Pension Benefits 2011	Pension Benefits 2010	Postretirement Benefits 2011	Postretirement Benefits 2010
		(In millions)		
Change in plan assets				
Fair value of plan assets at January 1	**$ 1,408.1**	$ 1,058.1	**$**	$
Actual return on plan assets	**89.5**	148.8		
Employer contribution (1)	**84.3**	289.1	**15.3**	18.5

Plan participants' contributions			**9.7**	10.5
Acquisition of Boston Generating Plan	**3.0**			
Settlements	**(6.0)**	(5.2)		
Benefits paid (2)(3)	**(91.2)**	(82.7)	**(25.0)**	(29.0)
Fair value of plan assets at December 31	**$ 1,487.7**	$ 1,408.1	**$**	$

(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 and Early Retiree Reimbursement Program 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,	**2011**	**2010**	**2009**
		(In millions)	
Components of net periodic pension benefit cost			
Service cost	**$ 50.3**	$ 37.9	$ 50.8
Interest cost	**87.4**	84.7	101.1
Expected return on plan assets	**(114.9)**	(101.8)	(118.9)
Amortization of unrecognized prior service cost	**3.9**	3.9	10.9
Recognized net actuarial loss	**44.6**	34.4	38.3
Amount capitalized as construction cost	**(10.6)**	(10.2)	(10.2)
Net periodic pension benefit cost (1)	**$ 60.7**	$ 48.9	$ 72.0

(1)

Net periodic pension benefit cost excludes settlement charges of $4.0 million and termination benefits of $0.2 million in 2011, settlement charge of $1.5 million and termination benefits of $0.6 million in 2010, and a settlement charge of $9.0 million and a termination benefit of $0.1 million in 2009. BGE's portion of our net periodic pension benefit costs, excluding amount capitalized, was $34.0 million in 2011, $30.9 million in 2010, and $27.9 million in 2009. The vast majority of our retirees were BGE employees.

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

Year Ended December 31,	2011	2010	2009
	(In millions)		
Components of net periodic postretirement benefit cost			
Service cost	**$ 2.9**	$ 2.4	$ 6.3
Interest cost	**17.1**	17.7	22.6
Amortization of transition obligation	**1.7**	2.1	2.1
Recognized net actuarial loss	**1.5**	0.4	2.2
Amortization of unrecognized prior service cost	**(2.7)**	(2.6)	(3.4)
Amount capitalized as construction cost	**(5.3)**	(5.4)	(6.3)
Net periodic postretirement benefit cost (1)	**$ 15.2**	$ 14.6	$ 23.5

(1)

Net periodic postretirement benefit cost excludes termination benefits of $0.1 million in 2010. BGE's portion of our net periodic postretirement benefit cost, excluding amounts capitalized, was $17.5 million in 2011, $17.2 million in 2010, and $18.7 million in 2009.

In determining net periodic pension benefit cost, we apply our expected return on plan assets to a market-related value of plan assets that recognizes asset gains and losses ratably over a five-year period.

The following is a summary of amounts we have recorded in "Accumulated other comprehensive loss" and of expected amortization of those amounts over the next twelve months:

	Pension Benefits		Postretirement Benefits		Expected Amortiz-ation Next
	2011	2010	2011	2010	12 Months
			(In millions)		
Unrecognized actuarial loss	**$ 864.6**	$ 741.4	**$ 70.5**	$ 65.3	$ 60.1
Unrecognized prior service cost	**1.9**	6.1	**(10.0)**	(14.0)	(0.5)
Unrecognized transition obligation			**1.8**	3.5	1.8
Total	**$ 866.5**	$ 747.5	**$ 62.3**	$ 54.8	$ 61.4

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 in the following table. These estimated benefits are based on the same assumptions used to measure the benefit obligation at December 31, 2011, but include benefits attributable to estimated future employee service.

	Pension Benefits	Postretirement Benefits (1)
2012	$ 109.2	$ 22.4
2013	107.6	23.0
2014	114.2	23.5
2015	165.7	23.9
2016	129.9	24.3
2017-2021	715.0	123.4

(1)

Postretirement benefit payments are net of Medicare Part D reimbursements.

Assumptions

We made the assumptions below to calculate our pension and postretirement benefit obligations and periodic cost.

	Pension Benefits (1)		**Postretirement Benefits**		**Assumption Impacts**
	2011	**2010**	**2011**	**2010**	**Calculation of**
Discount rate as of January 1	**5.50%**	6.00%	**5.50%**	6.00%	Periodic Cost
Discount rate as of December 31	**4.75%**	5.50%	**4.75%**	5.50%	Benefit Obligation
Expected return on plan assets	**8.00**	8.50	**N/A**	N/A	Periodic Cost
Rate of compensation increase	**4.0**	4.0	**4.0**	4.0	Benefit Obligation and Periodic Cost

(1)

The Boston Generating Plan made the following assumptions to calculate its pension benefit obligation and periodic cost: discount rate as of January 3, 2011, the date of acquisition, 5.10%, discount rate as of December 31, 2011 4.20%, expected return on plan assets 8.00%, and rate of compensation increase 4.0%.

Our discount rate is based on a bond portfolio analysis of high quality corporate bonds whose maturities match our expected benefit payments. Our 8.00% overall expected long-term rate of return on plan assets reflected our long-term investment strategy in terms of asset mix and expected returns for each asset class at the beginning of 2011. Effective in 2012, we reduced our expected long-term rate of return assumption to 7.50% reflecting our updated investment strategy, asset mix, and expected return for each asset class.

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,	**2011**	**2010**
Next year	**7.5%**	8.5%
Following year	**7.0%**	7.5%
Ultimate trend rate	**5.0%**	5.0%
Year ultimate trend rate reached	**2017**	2017

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A one-percentage point increase in the health care inflation rate from the assumed rates would increase the accumulated postretirement benefit obligation by approximately $22.1 million as of December 31, 2011 and would increase the combined service and interest costs of the postretirement benefit cost by approximately $1.3 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 $19.1 million as of December 31, 2011 and would decrease the combined service and interest costs of the postretirement benefit cost by approximately $1.1 million annually.

Qualified Pension Plan Assets

Investment Strategy

We invest our qualified pension plan assets using the following investment objectives:

- ensure availability of funds for payment of plan benefits as they become due,
- provide for a reasonable amount of long-term growth of capital (both principal and income) without excessive volatility,
- produce investment results that meet or exceed the assumed long-term rate of return,
- improve the funded status of the plan over time, and
- reduce future contribution and expense volatility as funded status improves.

To achieve these objectives, Constellation Energy, through a management Investment Committee (the Committee), which includes any advisors or experts that the Committee may hire, has adopted an investment strategy that divides its pension investment program into two primary portfolios:

- return seeking assets those assets intended to generate returns in excess of pension liability growth, and
- liability hedging assets those assets intended to have characteristics similar to pension liabilities.

Currently, the Committee allocates 60% of its plan assets to return seeking assets to help reduce existing deficits in the funded status of the plan. As the funded status of our plans improves, the Committee expects to reduce its exposure to return seeking assets and increase its liability hedging assets to reduce its total risk.

Return Seeking Assets

The purpose of return seeking assets is to provide investment returns in excess of the growth of pension liabilities. This category includes a diversified portfolio of public equities, private equity, real estate, hedge funds, high yield bonds and other instruments. These assets are likely to have lower correlations with the pension liabilities and lead to higher funded status risk over shorter periods of time.

Liability Hedging Assets

The purpose of liability hedging assets, such as long duration bonds and interest rate derivatives, is to hedge against interest rate changes. Exposure to liability hedging assets is intended to reduce the volatility of plan funded status, contributions, and pension expense.

Risk Management

The Committee manages plan asset risk using several approaches. First, the assets are invested in two diverse portfolios: a growth portfolio and a portfolio that hedges changes in the liability due to interest rate movement. Each portfolio contains investments across a spectrum of asset classes. Second, the Committee considers the long-term investment horizon of the plan, which is greater than ten years. The long-term horizon enables the Committee to tolerate the risk of investment losses in the short-term with the expectation of higher returns in the long-term. Third, the Committee employs a thorough due diligence program prior to selecting an investment, and a rigorous ongoing monitoring program once assets are invested. The Committee evaluates risk on an ongoing basis.

Asset Allocation

Plan assets are diversified across various asset classes and securities based on the investment strategy approved by the Committee. This policy allocation is long-term oriented and consistent with the risk tolerance and funded status. The target asset allocation as well as the actual allocations for 2011 and 2010 are provided below.

	Target Allocation		Actual Allocation	
At December 31,	**2011**	**2010**	**2011**	**2010**
Global equity securities	**42%**	42%	**38%**	42%
Fixed income securities	**40**	40	**42**	37
Alternative investments	**12**	12	**11**	8
High yield bonds	**6**	6	**6**	6
Cash and cash equivalents			**3**	7
Derivative instruments				
Total	**100%**	100%	**100%**	100%

The target asset allocation allows for investments in financial derivatives to hedge against liability changes caused by interest rate movement and capture security price volatility. These instruments are sensitive to changes in economic conditions.

The Committee will also rebalance our portfolio periodically when the actual allocations fall outside of the ranges prescribed in the investment policy or as the funded status improves.

Fair Value Hierarchy

We determine the fair value of the plan assets 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 within this fair value hierarchy based on the lowest level of

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input that is significant to the fair value measurement of each individual asset taken as a whole.

The following tables set forth by level, within the fair value hierarchy, the investments in the Plans' master trust at fair value as of December 31, 2011 and 2010:

At December 31, 2011	**Level 1**	**Level 2**	**Level 3**	**Total Fair Value**
		(In millions)		
Global equity securities:				
Money market funds (1)	$ 22.6	$	$	$ 22.6
Marketable equity securities	125.5			125.5
Common collective trusts		420.4		420.4
Mutual funds	2.2			2.2
Fixed income securities:				
Money market funds (1)	20.4			20.4
Corporate debt securities		327.3		327.3
Government / agency securities		178.2		178.2
Municipal bonds		73.3		73.3
Guarantee insurance contracts		20.6		20.6
Asset and mortgage-backed securities		1.8		1.8
Mutual funds	1.0			1.0
High yield bonds:				
Money market funds (1)	5.4			5.4
Corporate debt securities		76.9		76.9
Cash equivalents	49.0			49.0
Derivative instruments		0.4		0.4
Alternative investments			162.7	162.7
Total	$ 226.1	$ 1,098.9	$ 162.7	$ 1,487.7

(1) *Money market funds available for the portfolio manager to invest have been included within the respective security classification to differentiate from the actual cash position of the pension trust.*

At December 31, 2010	**Level 1**	**Level 2**	**Level 3**	**Total Fair Value**
		(In millions)		
Global equity securities:				
Money market funds (1)	$ 26.1	$	$	$ 26.1
Marketable equity securities	143.6			143.6
Common collective trusts		421.4		421.4
Fixed income securities:				
Money market funds (1)	9.8			9.8
Corporate debt securities		318.0		318.0
Government / agency securities		112.7		112.7
Municipal bonds		54.8		54.8
Guarantee insurance contracts		21.6		21.6
Asset and mortgage-backed securities		0.4		0.4
High yield bonds:				
Money market funds (1)	4.7			4.7
Corporate debt securities		82.2		82.2
Cash equivalents	93.6			93.6

Derivative instruments		0.9		0.9
Alternative investments			118.3	118.3
Total	$ 277.8	$ 1,012.0	$ 118.3	$ 1,408.1

(1)
Money market funds available for the portfolio manager to invest have been included within the respective security classification to differentiate from the actual cash position of the pension trust.

The following is a description of the valuation methodologies used for assets measured at fair value:

Global equity securities, which include marketable equity securities common collective trust securities, and mutual funds are valued at unadjusted quoted market share prices within active markets (Level 1) or based on external price/spread data of comparable securities (Level 2). Common collective trust funds within this category are valued at fair value based on the unit value of the fund which is observable on a less frequent basis (Level 2). Unit values are determined by the bank or financial institution sponsoring such funds by dividing the fund's net assets at fair value by its units outstanding at the valuation dates.

Fixed income (primarily corporate debt securities, government and agency securities, municipal bonds, guarantee insurance contracts, asset and mortgage-backed securities, and mutual funds), high yield bonds, and over-the-counter derivatives are valued based on external price data of comparable securities (Level 2).

Cash equivalents consist of money market funds, which are valued by multiplying unadjusted quoted prices in active markets by the quantity of the assets (Level 1).

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Alternative investments primarily consist of hedge funds, real estate funds, and financial limited partnerships (private equity funds). These investments do not have readily determinable fair values because they are not listed on national exchanges or over-the-counter markets. We have valued these alternative investments at their respective net asset value per share (or its equivalent such as partner's capital) which has been calculated by each partnership's general partner in a manner consistent with generally accepted accounting principles in the United States of America for investment companies. Among other requirements, the partnerships must value their underlying investments at fair value. While the net asset value per share provides a reasonable approximation of fair value, the fair values of the alternative investments are estimates and, accordingly, such estimated values may differ from the values that would have been used had a ready market for the investments existed, and the differences could be material.

The following table summarizes the changes in the fair value of the Level 3 assets for the years ended December 31, 2011 and 2010:

	Year Ended December 31, 2011	Year Ended December 31, 2010
	(In millions)	
Balance at beginning of period	**$ 118.3**	$ 74.4
Actual return on plan assets:		
Assets still held at year end	**(11.1)**	(32.1)
Assets sold during the year	**7.4**	37.0
Purchases	**160.3**	
Sales	**(112.2)**	
Net purchases, sales, and settlements	**48.1**	22.2
Transfers into Level 3		16.8
Transfers out of Level 3		
Balance at end of year	**$ 162.7**	$ 118.3

Contributions and Benefit Payments

We contributed $75.6 million to our qualified pension plans in 2011, of which $53.6 million was contributed by BGE. $75.0 million of this contribution was an acceleration of estimated calendar year 2012 contributions. Therefore, we do not plan to make contributions to our qualified pension plans in 2012. Our non-qualified pension plans and our postretirement benefit programs are not funded. We estimate that we will incur approximately $5 million in pension benefits for our non-qualified pension plans and approximately $22 million for retiree health and life insurance costs net of Medicare Part D during 2012.

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, and
- income replacement payments for 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 $3.0 million in 2011, $9.9 million in 2010, and $5.3 million in 2009. BGE's portion of expense associated with other postemployment benefits was $2.8 million in 2011, $7.6 million in 2010, and $4.4 million in 2009.

We assumed the discount rate for other postemployment benefits to be 3.00% as of December 31, 2011 and 4.00% as of December 31, 2010. This assumption impacts the calculation of our other postemployment benefit obligation and periodic cost.

Employee Savings Plan Benefits

We sponsored two defined contribution plans until November 6, 2009, when upon the close of the sale of a 49.99% interest in CENG to EDF, we deconsolidated CENG and the defined contribution plan related to Nine Mile Point was removed from our books. For all remaining eligible employees of Constellation Energy, we continue to sponsor a defined contribution savings plan. The savings plan is a qualified 401(k) plan 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 were as follows:

Year Ended December 31,	**2011**	2010	2009
		(In millions)	
Nonregulated businesses	**$ 10.1**	$ 9.9	$ 14.8
BGE	**6.6**	6.3	5.7
Total Constellation Energy	**$ 16.7**	$ 16.2	$ 20.5

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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. We enter into these facilities to ensure adequate liquidity to support our operations.

Constellation Energy

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

Constellation Energy had bank lines of credit under committed credit facilities totaling $4.2 billion at December 31, 2011 for short-term financial needs as follows:

Type of Credit Facility	Amount (In billions)	Expiration Date	Capacity Type
Syndicated Revolver(1)	$ 2.50	October 2013	Letters of credit and cash
Commodity-linked	0.50	August 2014	Letter of credit and cash
Bilateral	0.55	September 2014	Letters of credit
Bilateral	0.25	December 2014	Letters of credit and cash
Bilateral	0.25	June 2014	Letters of credit and cash
Bilateral	0.15	September 2013	Letters of credit
Total	$ 4.20		

(1) *Upon closing of the merger with Exelon, the amount available under this facility will be $1.5 billion.*

At December 31, 2011, we had approximately $1.5 billion in letters of credit issued, including $0.5 billion in letters of credit issued under the commodities-linked credit facility discussed below, and no commercial paper outstanding under these facilities.

The commodity-linked credit facility currently allows for the issuance of letters of credit and, as modified in 2010, for cash borrowings, up to a maximum capacity of $0.5 billion. This commodity-linked facility is designed to help manage our contingent collateral requirements associated with the hedging of our NewEnergy business because its capacity increases up to the maximum capacity as natural gas price levels decrease compared to a reference price that is adjusted periodically.

At December 31, 2011, Constellation Energy had $39.5 million of short-term notes outstanding with a weighted-average effective interest rate of 2.59%.

BGE

BGE has a $600.0 million revolving credit facility expiring in March 2015. BGE can borrow directly from the banks, use the facility to allow commercial paper to be issued, if available, or issue letters of credit. At December 31, 2011, BGE had no commercial paper outstanding. There were immaterial letters of credit outstanding at December 31, 2011.

Net Available Liquidity

The following table provides a summary of our net available liquidity at December 31, 2011:

At December 31, 2011	Constellation Energy (excluding BGE)	BGE
	(In billions)	
Credit facilities (1)	$ 3.7	$ 0.6
Less: Letters of credit issued (1)	(1.0)	
Less: Cash drawn on credit facilities		
Undrawn facilities	2.7	0.6
Less: Commercial paper outstanding		
Net available facilities	2.7	0.6
Add: Cash and cash equivalents (2)	0.9	
Net available liquidity	$ 3.6	$ 0.6

(1) *Excludes $0.5 billion commodity-linked credit facility due to its contingent nature and $0.5 billion in letters of credit posted against it.*

(2) *BGE's cash balance at December 31, 2011 was $48.6 million.*

Credit Facility Compliance and Covenants

The credit facilities of Constellation Energy and BGE contain a material adverse change representation but draws on the facilities are not conditioned upon Constellation Energy and BGE making this representation at the time of the draw. However, to the extent a material adverse change has occurred and prevents Constellation Energy or BGE from making other representations that are required at the time of the draw, the draw would be prohibited.

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, 2011, the debt to capitalization ratio as defined in the credit agreements was 38%.

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, 2011, the debt to capitalization ratio for BGE as defined in this credit agreement was 46%.

Decreases in Constellation Energy's or BGE's credit ratings would not trigger an early payment on any of our, or BGE's, credit facilities. However, the impact of a credit ratings downgrade on our financial ratios associated with our credit facility covenants would depend on our financial condition at the time of such a downgrade and on the source of funds used to satisfy the incremental collateral obligation resulting from a credit ratings downgrade. For example, if we were to use existing cash balances to fund the cash portion of any additional collateral obligations resulting from a credit ratings downgrade, we would not expect a material impact on our financial ratios. However, if we were to issue long-term debt or use our credit facilities to fund any additional collateral obligations, our financial ratios could be materially affected. Failure by Constellation Energy, or BGE, to comply with these covenants could result in the acceleration of the maturity of the borrowings outstanding and preclude us from issuing letters of credit under these facilities.

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9 Capitalization

We detail in the table below our total capitalization, which includes long-term debt, common stock, noncontrolling interests, and preference stock, as of December 31, 2011 and 2010.

At December 31,	2011	2010
	(In millions)	
Long-Term Debt		
Long-term debt of Constellation Energy		
8.625% Series A Junior Subordinated Debentures, due June 15, 2063	**$ 450.0**	$ 450.0
7.00% Fixed-Rate Notes, due April 1, 2012		213.5
4.55% Fixed-Rate Notes, due June 15, 2015	**550.0**	550.0
5.15% Fixed-Rate Notes, due December 1, 2020	**550.0**	550.0
7.60% Fixed-Rate Notes, due April 1, 2032	**700.0**	700.0
Fair Value of Interest Rate Swaps	**44.1**	36.2
Total long-term debt of Constellation Energy	**2,294.1**	2,499.7
Long-term debt of nonregulated businesses		
Tax-exempt debt transferred from BGE effective July 1, 2000		
4.10% Pollution control loan, due July 1, 2014	**20.0**	20.0
Tax-exempt variable rate notes, due April 1, 2024	**75.0**	75.0
7.3% Fixed Rate Note, due June 1, 2012	**1.6**	1.7
Upstream Gas Property asset-based lending agreement due July 16, 2016	**83.0**	18.0
Secured Solar Credit Lending Agreement due July 7, 2014	**130.0**	
Sacramento Solar Project Financing Agreement due December 31, 2030	**40.7**	
Denver International Airport Solar Loan Agreement due June 30, 2031	**7.5**	
Holyoke Solar, LLC Loan Agreement due December 31, 2031	**11.0**	
Total long-term debt of nonregulated businesses	**368.8**	114.7
Other long-term debt of BGE		
3.50% Notes, due November 15, 2021	**300.0**	
6.125% Notes, due July 1, 2013	**400.0**	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	**109.6**	131.5
Total other long-term debt of BGE	**1,709.6**	1,431.5
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	**394.6**	454.4
Unamortized discount and premium	**(5.1)**	(3.9)
Current portion of long-term debt	**(174.9)**	(305.3)
Total long-term debt	**$ 4,844.8**	$ 4,448.8

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At December 31,	2011	2010
	(In millions)	
Equity:		
Noncontrolling Interests	**$ 116.9**	$ 88.8
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 $100.71 per share until June 30, 2012, and at lesser amounts thereafter	**40.0**	40.0
6.97%, 1993 Series, 500,000 shares outstanding, callable at $100.70 per share until September 30, 2012, and at lesser amounts thereafter	**50.0**	50.0
6.70%, 1993 Series, 400,000 shares outstanding, callable at $100.67 per share until December 31, 2012, and at lesser amounts thereafter	**40.0**	40.0
6.99%, 1995 Series, 600,000 shares outstanding, callable at $101.40 per share until September 30, 2012, and at lesser amounts thereafter	**60.0**	60.0
Total BGE preference stock not subject to mandatory redemption	**190.0**	190.0
Common Shareholders' Equity		
Common stock without par value, 600,000,000 shares authorized; 201,686,291 and 199,788,658 shares issued and outstanding at December 31, 2011 and 2010, respectively. (At December 31, 2011, 10,143,863 shares were reserved for the long-term incentive plans, 8,542,059 shares were reserved for the shareholder investment plan, and 1,223,050 shares were reserved for the employee savings plan.)	**3,292.2**	3,231.7
Retained earnings	**4,738.0**	5,270.8
Accumulated other comprehensive (loss) income:		
Hedging instruments	**(404.0)**	(228.7)
Available-for-sale securities	**38.9**	34.5
Defined benefit plans	**(558.3)**	(481.1)
Foreign currency translation and other	**(12.9)**	2.0
Total accumulated other comprehensive loss	**(936.3)**	(673.3)
Total common shareholders' equity	**7,093.9**	7,829.2
Total Equity	**7,400.8**	8,108.0
Total Capitalization	**$ 12,245.6**	$ 12,556.8

BGE Common Shareholder Equity

At December 31,	2011	2010
	(In millions)	
Common Stock	**$ 1,293.1**	$ 1,293.1
Retained Earnings	**817.0**	779.5
Accumulated other comprehensive income	**0.6**	0.6
Total BGE common shareholder equity	**$ 2,110.7**	$ 2,073.2

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

5.15% Notes due December 1, 2020

In December 2010, we issued $550 million of 5.15% Notes due December 1, 2020. Interest is payable semi-annually on June 1 and December 1, beginning June 1, 2011. At any time prior to September 1, 2020, we may redeem some or all of the notes at a price equal to the greater of 100% of the principal amount of the notes outstanding to be redeemed and the sum of the present values of the remaining scheduled payments of principal and interest on the notes being redeemed, discounted to the redemption date on a semi-annual basis at the Treasury rate plus 30 basis points, plus accrued interest. After September 1, 2020, we may redeem some or all of the notes at a price equal to 100% of the principal amount of the notes outstanding to be redeemed plus accrued interest on the principal amount being redeemed to the redemption date.

Additionally, in December 2010, we issued a notice to redeem $213.5 million of our 7.00% Notes, which represented the remaining outstanding 7.00% Notes due April 1, 2012. As such, we classified these notes as "Current portion of long-term debt" in our Consolidated Balance Sheets. In January 2011, we redeemed these notes with part of the proceeds from the issuance of the $550 million 5.15% Notes, terminated the associated interest rate swaps, and recognized a pre-tax loss of approximately $5 million on this transaction.

During February 2011, we entered into interest rate swaps qualifying as fair value hedges related to $350 million of our fixed rate debt maturing in 2015. We also entered into

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$150 million of interest rate swaps related to our fixed rate debt maturing in 2020 that do not qualify as fair value hedges, and will be marked to market through earnings. These swaps effectively converted $500 million notional amount of fixed rate debt to floating rate for the term of the swaps.

We discuss our interest rate swaps in *Note 13*.

Secured Solar Credit Lending Agreement

In July 2011, a subsidiary of Constellation Energy entered into a three-year senior secured credit facility that is designed to support the growth of our solar operations. The amount committed under the facility is $150 million, which may be increased up to $200 million at the subsidiary's request with additional commitments by the lenders. At December 31, 2011, we had borrowed $130.0 million. Borrowings incur interest at a variable rate payable quarterly and are secured by the equity interests in the subsidiary and the entities that own the solar projects as well as the assets of the subsidiary and the projects' entities. The obligations of our subsidiary are guaranteed by Constellation Energy and the projects' entities. The Constellation Energy guarantee will terminate upon the subsidiary obtaining a stand-alone investment grade credit rating or the satisfaction of a number of conditions, at which time the financing will become nonrecourse to Constellation Energy.

Sacramento Solar Project Financing

In July 2011, a subsidiary of Constellation Energy entered into a $40.7 million nonrecourse project financing to fund construction of our 30MW solar facility in Sacramento, California. Borrowings will incur interest at a variable rate, payable quarterly, and are secured by the equity interests and assets of the subsidiary. The construction borrowings are expected to convert into a 19-year nonrecourse variable note in the first quarter of 2012. The subsidiary also executed interest rate swaps for a notional amount of $30.6 million in order to convert the variable interest payments to fixed payments on the $40.7 million facility amount. We discuss our use of derivative instruments, including interest rate swaps, to manage our interest rate risk in more detail in *Note 13*.

In addition to this facility, this subsidiary entered into a treasury grant bridge loan for $26.0 million and an equity bridge loan for $27.9 million. Both loans will be utilized to fund construction. The equity bridge loan is expected to be repaid in the first quarter of 2012 and the treasury grant is expected to be repaid in the second quarter of 2012.

Other Solar Project Financings

During 2011, we borrowed the following amounts under solar project loan agreements:

- $7.5 million due June 30, 2031 related to a solar project at the Denver International Airport, and
- $11.0 million due December 31, 2031 related to a solar project in Holyoke, Massachusetts.

Upstream Gas Property Asset-Based Lending Agreement

In July 2009, we entered into a three year asset-based lending agreement associated with certain upstream gas properties that we own. In July 2011, we amended and extended this lending agreement. The borrowing base committed under the facility was increased to $150 million and can increase to a total of $500 million if the assets support a higher borrowing base and we are able to obtain additional commitments from lenders. The facility now expires in July 2016. Borrowings under this facility are secured by the upstream gas properties, and the lenders do not have recourse against Constellation Energy in the event of a default. At December 31, 2011, we had borrowed $83.0 million under the facility with interest payable quarterly. The facility includes a provision that requires our entities that own the upstream gas properties subject to the agreement to maintain a current ratio of one-to-one. As of December 31, 2011, we are compliant with this provision.

BGE

3.50% Notes due November 15, 2021

In November 2011, BGE issued $300 million of 3.50% Notes due November 15, 2021. Interest is payable semi-annually on May 15 and November 15, beginning May 15, 2012. At any time prior to August 15, 2021, BGE may redeem some or all of the notes at a price equal to the greater of 100% of the principal amount of the notes outstanding to be redeemed and the sum of the present values of the remaining scheduled payments of principal and interest on the notes being redeemed, discounted to the redemption date on a semi-annual basis at the Treasury rate plus 25 basis points, plus accrued interest. After August 15, 2021, BGE may redeem some or all of the notes at a price equal to 100% of the principal amount of the notes outstanding to be redeemed plus accrued interest on the principal amount being redeemed to the redemption date.

Secured Indenture

BGE entered into a secured indenture in July 2009. The secured indenture creates a first priority lien on substantially all of BGE's electric utility distribution equipment and fixtures and on BGE's franchises, permits, and licenses that are transferable and necessary for the operation of the equipment and fixtures. As of December 31, 2011, BGE has not issued any secured bonds under this indenture.

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, 2011:

Principal	**Interest Rate**	**Scheduled Maturity Date**
$55.4	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

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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

On July 1, 2000, BGE transferred $278.0 million of tax-exempt debt to our Generation business related to the transferred generating assets. At December 31, 2011, BGE remains contingently liable for the $20 million outstanding balance of this debt.

BGE's fixed-rate medium-term note, series E, outstanding at December 31, 2011 has a weighted average interest rate of 6.75%, maturing in 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 in the future 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.

Maturities of Long-Term Debt

As of December 31, 2011, our long-term borrowings mature on the following schedule:

Year	Constellation Energy	Nonregulated Businesses	BGE	Total
		(In millions)		
2012	$	$ 2.4	$ 172.5	$ 174.9
2013		2.5	466.6	469.1
2014		152.5	70.4	222.9
2015	594.1	2.6	74.5	671.2
2016		84.2	378.9	463.1
Thereafter	1,700.0	124.6	1,199.0	3,023.6
Total	$ 2,294.1	$ 368.8	$ 2,361.9	$ 5,024.8

Weighted-Average Interest Rates for Variable Rate Debt

Our weighted-average interest rates for variable rate debt outstanding were:

At December 31,	2011	2010

Nonregulated Businesses (including Constellation Energy)		
Loans under credit agreements	**2.88%**	4.50%
Tax-exempt debt	**0.21%**	0.30%
Fixed-rate debt converted to floating (1)	**1.55%**	1.23%

(1) *Includes $150 million of floating rate swaps related to fixed rate debt maturing in 2020 for four years of the 10-year term note.*

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.

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Dividend Restrictions

Constellation Energy

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, unless Constellation Energy elects to defer interest payments on the 8.625% Series A Junior Subordinated Debentures due June 15, 2063, and any deferred interest remains unpaid. The merger agreement with Exelon prohibits us from increasing our common stock dividend without Exelon's consent.

BGE

BGE pays dividends on its common stock after its Board of Directors declares them. However, pursuant to the order issued by the Maryland PSC on October 30, 2009 in connection with its approval of the transaction with EDF, BGE cannot pay dividends to Constellation Energy if (a) after the dividend payment, BGE's equity ratio would be below 48% as calculated pursuant to the Maryland PSC's ratemaking precedents or (b) BGE's senior unsecured credit rating is rated by two of the three major credit rating agencies below investment grade.

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10 Taxes

The components of income tax expense are as follows:

Year Ended December 31,	2011	2010	2009
	(Dollar amounts in millions)		
Income Taxes			
Current			
Federal	**$ (56.0)**	$ (46.9)	$ 891.5
State	**23.2**	102.0	260.4
Current taxes charged to expense	**(32.8)**	55.1	1,151.9
Deferred			
Federal	**(134.1)**	(521.4)	1,474.5
State	**(59.7)**	(194.9)	372.5
Deferred taxes (credited) charged to expense	**(193.8)**	(716.3)	1,847.0
Investment tax credit adjustments	**(4.3)**	(4.5)	(12.1)
Income taxes per Consolidated Statements of Income (Loss)	**$ (230.9)**	$ (665.7)	$ 2,986.8

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	**$ (537.7)**	$ (1,597.5)	$ 7,490.2
Statutory federal income tax rate	**35%**	35%	35%
Income taxes computed at statutory federal rate	**(188.2)**	(559.1)	2,621.6
Increases (decreases) in income taxes due to			
State income taxes, net of federal income tax benefit	**(23.8)**	(60.4)	411.0
Merger-related transaction costs			(79.3)
Interest expense on mandatorily redeemable preferred stock			23.7
Qualified decommissioning impairment losses			3.1
Amortization of deferred investment tax credits	**(4.3)**	(4.5)	(12.1)
Noncontrolling interest operating results	**(7.1)**	(13.1)	(16.4)
Nondeductible international losses			19.2
Other	**(7.5)**	(28.6)	16.0
Total income taxes	**$ (230.9)**	$ (665.7)	$ 2,986.8
Effective income tax rate	**42.9%**	41.7%	39.9%

BGE's effective tax rate was 35.1% in 2011, 39.7% in 2010, and 41.3% in 2009. 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 2011 is primarily due to the favorable impact from the IRS National Office guidance regarding BGE's change of accounting for tax purposes with respect to certain electric transmission and distribution expenditures and the partial reversal of an unfavorable deferred tax adjustment recorded in 2010 as a result of healthcare reform legislation that eliminated the tax exempt treatment of prescription drug subsidies received under Medicare Part D. The partial reversal in 2011 resulted from the Maryland PSC's authorization for BGE to create an electric regulatory asset for this tax law change and amortize the balance over a five-year period. The decrease in BGE's 2010 effective tax rate from 2009 is primarily due to the inclusion of a minority interest loss in pre-tax earnings in 2009 that was not included in 2010 pre-tax earnings because of BGE's sale of the interest in January 2010.

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The major components of our net deferred income tax liability are as follows:

	Constellation Energy		BGE	
At December 31,	**2011**	**2010**	**2011**	**2010**
	(In millions)			
Deferred Income Taxes				
Deferred tax liabilities				
Net property, plant and equipment	**$ 2,020.4**	$ 1,768.3	**$ 1,220.1**	$ 1,152.3
Regulatory assets, net	**282.6**	256.8	**282.6**	256.8
Derivative assets and liabilities, net	**(84.6)**	(34.1)		
Investment in CENG	**604.5**	1,044.3		
Other	**156.3**	12.1	**21.6**	(80.0)
Total deferred tax liabilities	**2,979.2**	3,047.4	**1,524.3**	1,329.1
Deferred tax assets				
Defined benefit obligations	**305.0**	249.0	**(93.1)**	(79.7)
Financial investments and hedging instruments	**217.6**	111.4		
Asset retirement obligations	**10.9**	10.9		
Deferred investment tax credits	**9.6**	10.9	**3.1**	3.2
Other	**263.0**	118.9	**71.1**	20.6
Total deferred tax assets	**806.1**	501.1	**(18.9)**	(55.9)
Total deferred tax liability, net	**2,173.1**	2,546.3	**1,543.2**	1,385.0
Less: Current portion of deferred tax liability/(asset)	**(132.0)**	56.5	**59.0**	30.1
Long-term portion of deferred tax liability, net	**$ 2,305.1**	$ 2,489.8	**$ 1,484.2**	$ 1,354.9

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 2008. In August 2011, we formally agreed to an assessment of tax by the IRS for the 2005 - 2007 tax years. The assessment did not have a material impact on our, or BGE's, financial condition or results of operation.

The IRS has audited our consolidated federal income tax return for the 2008 tax year and completion of the audit is awaiting additional industry guidance from the IRS National Office regarding BGE's change of accounting for tax purposes with respect to certain electric and gas transmission and distribution expenditures. IRS industry guidance on electric transmission and distribution expenditures was issued in August 2011 and additional guidance on gas transmission and distribution expenditures is expected in 2012. Application and compliance with the IRS industry guidance for electric and gas transmission and distribution expenditures should result in the completion of the IRS examination for the 2008 tax year. The IRS is also currently auditing our consolidated federal income tax returns for the 2009 - 2010 tax years as well as examining the 2011 tax year concurrently as part of the IRS Compliance Assurance Process. Although the final outcome of the 2008 - 2011 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 2011 and 2010 and our total unrecognized tax benefits at December 31, 2011 and 2010:

	2011	2010
	(In millions)	
Total unrecognized tax benefits, January 1	$ 239.8	$ 312.5
Increases in tax positions related to the current year	3.1	5.9

Increases in tax positions related to prior years	29.6	26.0
Reductions in tax positions related to prior years	(90.6)	(104.0)
Reductions in tax positions as a result of a lapse of the applicable statute of limitations	(0.8)	(0.6)
Total unrecognized tax benefits, December 31 (1)	$ 181.1	$ 239.8

(1)
BGE's portion of our total unrecognized tax benefits at December 31, 2011 and 2010 was $11.4 million and $72.9 million, respectively.

If the total amount of unrecognized tax benefits of $181.1 million were ultimately realized, our income tax expense would decrease by approximately $169 million. However, the $169 million includes state tax refund claims of $55.9 million that have been disallowed by tax authorities and are subject to appeals.

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It is reasonably possible that unrecognized tax benefits could decrease within the next year by approximately $108 million as a result of a potential resolution with the IRS regarding BGE's change of accounting method for tax purposes with respect to certain gas transmission and distribution expenditures and certain state positions that are currently under audit or litigation. This decrease is not expected to have a material impact on our, or BGE's, financial condition or results of operation.

The decrease in unrecognized tax positions for the year ended December 31, 2011 is primarily related to the issuance of guidance from the IRS National Office in August 2011 regarding electric transmission and distribution expenditures. The decrease did not have a material impact on BGE's financial condition or results of operations.

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

	For the Year Ended December 31,		
	2011	**2010**	**2009**
		(In millions)	
Interest and penalties recorded as tax expense (benefit)	**$ 6.1**	$ (6.3)	$ 12.8

BGE's portion of interest and penalties was immaterial for all years.

Accrued interest and penalties recognized in our Consolidated Balance Sheets were $22.9 million, of which BGE's portion was $1.2 million at December 31, 2011, and $16.8 million, of which BGE's portion was $3.8 million, at December 31, 2010.

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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. We classify power purchase agreements as leases if the agreement in substance provides us the ability to control the use of the underlying power generating facilities.

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.

Through March 2009, we managed a global coal and logistics services operation. We entered into time charter purchase agreements which entitled us to the use of dry bulk freight vessels in connection with this operation. We continue to manage a residual position, which was not divested in 2009 with the remainder of the operation. Certain of these contracts must be accounted for as leases. These arrangements do not include provisions for material rent increases and do not have provisions for rent holidays, contingent rentals or other incentives. In 2011, 2010, and 2009, we recognized aggregate lease expense of approximately $7 million, $11 million and $145 million, respectively, related to 3, 12 and 31 dry bulk freight vessels, respectively, hired under time charter arrangements. 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)	
2011	$ 291.1	$ 31.7	$ 322.8
2010	227.9	30.2	258.1
2009	385.6	37.2	422.8

At December 31, 2011, we owed future minimum payments for long-term, noncancelable, operating leases as follows:

Year	Power Purchase Agreements	Other	Total
		(In millions)	
2012	$ 198.2	$ 32.0	$ 230.2
2013	190.9	29.6	220.5
2014	193.8	33.8	227.6
2015	193.3	19.8	213.1
2016	108.2	12.9	121.1
Thereafter	51.9	17.1	69.0
Total future minimum lease payments	$ 936.3	$ 145.2	$ 1,081.5

Sub-Lease Arrangements

In managing the residual position from our former coal and logistics services operation, we provide time charters of dry bulk freight vessels to global customers that qualify as sub-leases of our time charter purchase contracts. In 2011, 2010, and 2009, we recorded sub-lease income of approximately $2 million, $25 million and $114 million, respectively, related to our time charter sub-leases. We record sub-lease income as part of "Nonregulated revenues" in our Consolidated Statements of Income (Loss).

12 Commitments, Guarantees, and Contingencies

Commitments

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

Our Generation and NewEnergy businesses enter into various 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 2012 and 2030. In addition, our NewEnergy business enters into contracts for the purchase of energy, capacity and transmission rights for the delivery of energy to meet our physical obligations to our customers. These contracts expire in various years between 2012 and 2031.

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

Our regulated electric business enters into various long-term contracts for the procurement of electricity. As of December 31, 2011, these contracts expire between 2012 and 2014 and represent BGE's estimated requirements to serve residential and small commercial customers as follows:

Contract Duration	*Percentage of Estimated Requirements*
From January 1, 2012 to September 2012	100%
From October 2012 to May 2013	75
From June 2013 to September 2013	50
From October 2013 to May 2014	25

The cost of power under these contracts is recoverable under the Provider of Last Resort agreement reached with the Maryland PSC discussed in *Note 1,* and therefore are excluded from the table later in this Note.

Our regulated gas business enters into various contracts for the procurement, transportation, and storage of gas. Our regulated gas business has gas procurement contracts that expire between 2012 and 2014 and transportation and storage contracts that expire between 2012 and 2027. The cost of gas under these contracts is recoverable under BGE's gas cost adjustment clause discussed in *Note 1,* and therefore are excluded from the table later in this Note.

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

At December 31, 2011, we estimate our future obligations to be as follows:

	Payments				
	2012	2013-2014	2015-2016	Thereafter	Total
	(In millions)				

Competitive Businesses:					
Purchased capacity and energy	$ 501.1	$ 552.5	$ 338.5	$ 335.3	$ 1,727.4
Purchased energy from CENG (1)	1,000.0	2,075.3	1,566.7		4,642.0
Fuel and transportation	656.1	638.6	419.6	321.2	2,035.5
Long-term service agreements, capital, and other	22.9	6.3	2.4	0.9	32.5
Total competitive businesses	2,180.1	3,272.7	2,327.2	657.4	8,437.4
Corporate and Other:					
Long-term service agreements, capital, and other	190.4	52.1	43.7	96.9	383.1
Regulated:					
Purchase obligations and other	7.3	9.6			16.9
Total future obligations	$ 2,377.8	$ 3,334.4	$ 2,370.9	$ 754.3	$ 8,837.4

(1)

As part of reaching a comprehensive agreement with EDF in October 2010, we modified our existing power purchase agreement with CENG to be unit contingent through the end of its original term in 2014. Additionally, beginning in 2015 and continuing to the end of the life of the respective plants, we agreed to purchase 50.01% of the available output of CENG's nuclear plants at market prices. We have included in the table our commitments under this agreement for five years, the time period for which we have more reliable data. Further, we continue to own a 50.01% membership interest in CENG that we account for as an equity method investment. See Note 16 for more details on this agreement.

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 owned and contracted power producing facilities. Our load-serving power sales contracts extend for terms through 2031 and provide for the sale of energy to electric distribution utilities and certain retail customers. Our power sales contracts associated with our power producing facilities, including renewable energy, extend for terms into 2036 and provide for the sale of all or a portion of the actual output of certain of our owned and contracted power producing facilities. Substantially all long-term contracts were executed at pricing that approximated market rates, including profit margin, at the time of execution.

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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, 2011	***Stated Limit***
	(In billions)
Constellation Energy guarantees	$ 9.0
BGE guarantees	0.3
Total guarantees	$ 9.3

At December 31, 2011, Constellation Energy had a total of $9.3 billion in guarantees outstanding related to loans, credit facilities, and contractual performance of certain of its subsidiaries as described below.

- Constellation Energy guaranteed a face amount of $9.0 billion as follows:
  - $8.5 billion on behalf of our Generation and NewEnergy business to allow it 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 $1.5 billion at December 31, 2011, which represents the total amount the parent company could be required to fund based on December 31, 2011 market prices. For those guarantees related to our derivative liabilities, the fair value of the obligation is recorded in our Consolidated Balance Sheets.
  - $0.5 billion primarily on behalf of CENG's nuclear generating facilities for nuclear insurance and credit support to ensure these plants have funds to meet expenses and obligations to safely operate and maintain the plants. We recorded the fair value of $11.1 million for these guarantees on our Consolidated Balance Sheets.
- BGE guaranteed the Trust Preferred Securities of $250.0 million of BGE Capital Trust II.

Contingencies

Litigation

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

Merger with Exelon

In late April and early May 2011, shortly after Constellation Energy and Exelon announced their agreement to merge the two companies, twelve shareholder class action lawsuits were filed in the Circuit Court for Baltimore City in Maryland. Each class action suit was filed on behalf of a proposed class of the shareholders of Constellation Energy against Constellation Energy, members of Constellation Energy's board of directors, and Exelon. The shareholder class actions generally allege that the individual directors breached their fiduciary duties by entering into the proposed merger because they failed to maximize the value that the shareholders would receive from the merger, and failed to disclose adequately all material information relating to the proposed merger. The class actions also allege that Constellation Energy and Exelon aided and abetted the individual directors' breaches of their fiduciary duties. The lawsuits challenge the proposed merger, seek to enjoin a shareholder vote on the proposed merger until all material information is provided relating to the proposed merger, and ask for rescission of the proposed merger and any related transactions that have been completed as of the date that the court grants any relief. The class action lawsuits also seek certification as class actions, compensatory damages, costs and disbursements related to the action, including attorneys' and experts' fees, and rescission damages. Plaintiffs in three of the twelve lawsuits subsequently filed motions to consolidate all the lawsuits. The court has granted the motion to consolidate.

In August 2011, two shareholder class action lawsuits were filed in the United States District Court for the District of Maryland. The class actions generally assert that Constellation Energy's directors breached their fiduciary duties to Constellation Energy's shareholders in connection with the pending merger and that Constellation Energy's directors, Constellation Energy, and Exelon aided and abetted the alleged breaches and that Constellation Energy's directors, Constellation Energy and/or Exelon violated Section 14(a) of the Securities Exchange Act of 1934 based on alleged material misrepresentations and omissions in the preliminary joint proxy statement/prospectus filed on June 27, 2011. The class actions seek various forms of relief, including, among other things, a declaratory judgment, an injunction prohibiting the merger, fees, expenses, and other costs.

In the third quarter of 2011, the parties to the consolidated action in the state court and the two actions in the federal court entered into a memorandum of understanding setting forth an agreement in principle regarding the settlement of the actions. Under the agreement, Constellation Energy and Exelon agreed to provide certain additional disclosures in the joint proxy statement/prospectus relating to the merger. The agreement provides that the actions will be dismissed with prejudice and that the members of the class of Constellation Energy shareholders will release the defendants from all claims that were or could have been raised in the actions, including all claims relating to the merger. The agreement also provides that the plaintiffs' counsel may apply to the state court for an award of attorney's fees and expenses. The settlement is subject to customary conditions, including, among other things, the execution of definitive settlement papers and approval of the settlement by the state court.

Constellation Energy and Constellation Energy's directors believe the actions are without merit and that they have valid defenses to all claims asserted therein. They entered into the memorandum of understanding solely to eliminate the burden, expense, and uncertainties inherent in further litigation. If the state court does not approve the settlement or any of the other conditions to consummation of the settlement are not satisfied,

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Constellation Energy and Constellation Energy's directors will continue to defend their positions in these matters vigorously.

Securities Class Action

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

The Southern District of New York granted the defendants' motion to transfer the two securities class actions filed in Maryland to the District of Maryland, and the actions have since been transferred for coordination with the securities class action filed there. On June 18, 2009, the court appointed a lead plaintiff, who filed a consolidated amended complaint on September 17, 2009. On November 17, 2009, the defendants moved to dismiss the consolidated amended complaint in its entirety. On August 13, 2010, the District Court of Maryland issued a ruling on the motion to dismiss, holding that the plaintiffs failed to state a claim with respect to the claims of the common shareholders under the Securities Exchange Act of 1934 and limiting the suit to those persons who purchased Debentures in the June 2008 offering. In August 2011, plaintiffs requested permission from the court to file a third amended complaint in an effort to attempt to revive the claims of the common shareholders. Constellation Energy has filed an objection to the plaintiffs' request for permission to file a third amended complaint. Given that limited discovery has occurred, that the court has not certified any class and the plaintiffs have not quantified their potential damage claims, we are unable at this time to provide an estimate of the range of possible loss relating to these proceedings or to determine the ultimate outcome of the securities class actions 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 483 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 by BGE or Constellation Energy and a small minority of these cases have been resolved for amounts that were not material to our financial results.

Discovery begins in these cases once they are placed on the trial docket. At present, only a small number of our pending cases have reached the trial docket. Given the limited discovery, BGE and Constellation Energy do not know the specific facts that we believe are necessary for us to provide an estimate of the possible loss relating to 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.

Insurance and hold harmless agreements from contractors who employed the plaintiffs may cover a portion of any awards in the actions.

Federal Energy Regulatory Commission Investigation

The Federal Energy Regulatory Commission (FERC) staff in the Office of Enforcement, Division of Investigations, is conducting an investigation of our virtual transactions and physical schedules in and around the New York ISO from September 2007 through December 2008. On August 29, 2011, the FERC staff notified us of its preliminary findings relating to our alleged violation of FERC's rules in connection with these activities. We continue to cooperate fully with the FERC investigation and, on October 28, 2011, we delivered to the FERC staff a response to their preliminary findings letter explaining why our conduct was lawful and refuting any allegation of wrongdoing. On January 30, 2012, FERC issued a Staff Notice of Alleged Violations, which reiterated the allegation that we violated FERC's rules relating to virtual transactions in the New York ISO and physical schedules between the New York ISO and PJM, Ontario and ISO-New England, and reiterated FERC's view of the impact of those transactions on our financial positions. We are continuing to cooperate with the FERC staff in bringing this matter to resolution. If FERC determines to proceed in this matter, FERC will issue an Order to Show Cause and a report from their staff outlining in detail their allegations. This Order, which may be issued within the next few months, would initiate a litigation process for resolving the matter and disclose FERC's view of penalties and disgorgement, which could be several hundred million dollars. However, we cannot currently predict how this matter will be resolved. While we believe we have meritorious defenses to the allegations, the ultimate outcome of the proceeding could have a material effect on our financial results.

Environmental Matters

Solid and Hazardous Waste

In 1999, the EPA proposed to add the 68th Street Dump in Baltimore, Maryland to the Superfund National Priorities List, which is its list of sites targeted for clean-up and enforcement, and sent a general notice letter to BGE and 19 other parties identifying them as potentially responsible parties at the site. In March 2004, we and other potentially responsible parties formed the 68th Street Coalition and entered into consent order negotiations with the EPA to investigate clean-up options for the site under the Superfund Alternative Sites Program. In May 2006, a settlement among the EPA and 19 of the potentially responsible parties, including BGE, with respect to investigation of the site became effective. The settlement requires the potentially responsible parties, over the course of several years, to identify contamination at the site and recommend clean-up options. BGE is indemnified by a wholly owned subsidiary of Constellation Energy for most of the costs related to this settlement and clean-up of the site. The potentially responsible parties submitted their investigation of the range of clean-up options in the first quarter of 2011. Although the investigation and options provided to the EPA are still subject to EPA review, we believe that the range of estimated clean-up costs to be allocated among all of the potentially responsible parties will be between approximately $50 million and $64 million depending on the clean-up option selected by the EPA. The EPA is expected to make a final selection of one of the alternatives in 2012. As the alternative to be selected by the EPA and the allocation of the clean-up costs among the potentially responsible parties is not yet known, we cannot provide an estimate of the range of our possible loss.

Air Quality

In January 2009, the EPA issued a notice of violation (NOV) to a subsidiary of Constellation Energy, as well as to the other owners and the operator of the Keystone coal-fired power plant in Shelocta, Pennsylvania. We hold a 20.99% 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 have investigated the allegations and had a meeting with the EPA where they provided the EPA with both legal and factual documentation to support their position that no violations have occurred. Since that time, the EPA has not requested any further meeting or otherwise acted on the allegations. We believe there are meritorious defenses to the allegations contained in the NOV. Because there are significant facts in dispute and this matter is only in the NOV stage, at this time we cannot estimate the range of possible loss or predict whether a proceeding will be commenced.

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. Based on updated information regarding the remediation plan and the costs to cap the site, we have recorded a liability in our Consolidated Balance Sheets of approximately $22.7 million ($12.1 million of which was added in the fourth quarter of 2011), which includes the $1 million penalty and our estimate of probable costs to remediate contamination, replace drinking water supplies, monitor groundwater conditions, and otherwise comply with the consent decree. We have paid approximately $5.7 million of these costs as of December 31, 2011, resulting in a remaining liability at December 31, 2011 of $17.0 million.

Investment in CENG

On November 6, 2009, we completed the sale of a 49.99% membership interest in CENG to EDF. As a result of the sale, we now hold a 50.01% interest in CENG. As a 50.01% owner in CENG, we are subject to certain capital contribution requirements, which may be greater than the amount planned and, therefore, could have an adverse impact on our financial results.

In addition, if the fair value of our investment in CENG declines to a level below our carrying value and the decline is considered other-than-temporary, we may write down the investment to fair value, which would adversely affect our financial results. During 2011 and 2010, we recorded impairments of our investment in CENG. We discuss these impairment charges in more detail in *Note 2*.

We are also exposed to the same risks to which CENG is exposed. CENG owns and operates three nuclear generating facilities and is exposed to risks associated with operating these facilities and the risks of a nuclear accident.

Operating Risks

The operation of nuclear generating facilities involve routine risks, including,

- mechanical or structural problems,
- inadequacy or lapses in maintenance protocols,
- cost 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,
- limitations on the amounts and types of insurance coverage commercially available,
- uncertainties regarding both technological and financial aspects of decommissioning nuclear generating facilities,
- terrorist attacks, and
- environmental risks.

Nuclear Accidents

CENG is required to insure itself 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 $375 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 $12.6 billion. Under the retrospective assessment program, CENG 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. In the event of a nuclear accident, the cost of property damage and other expenses incurred may exceed CENG's insurance coverage. As a result, uninsured losses or the payment of retrospective insurance premiums could each have a significant adverse impact to CENG's, and therefore, our financial results as a 50.01% owner in CENG. Each of Constellation Energy and EDF has guaranteed the obligations of CENG under these insurance programs in proportion to their respective membership interests.

Property and Accidental Outage Insurance

CENG's nuclear plants are provided property and accidental outage insurance through Nuclear Electric Insurance Limited (NEIL). As the members-insured of NEIL through their ownership interest in CENG, Constellation Energy and EDF have assigned the loss benefits under the insurance to CENG's nuclear plants, with CENG named as an additional insured party. In consideration for receiving the loss benefits, CENG pays the NEIL premiums.

If claims at nuclear plants insured by NEIL result in a shortfall of NEIL reserve funds, all policy holders could be assessed a retrospective premium, for which the combined Constellation Energy and EDF premium share for the current policy year could be as much as $94.6 million.

NEIL requires its members-insured to maintain an investment grade credit rating, or alternatively, provide NEIL with certain financial guarantees to ensure that it can meet its potential retrospective premium obligations. Should Constellation Energy experience a downgrade to its credit ratings to below investment grade, Constellation Energy would be required by NEIL to:

- deposit funds with NEIL in the full amount of its retrospective premium obligation,
- obtain a guarantee from an investment grade rated entity,
- post a letter of credit in the full amount of its maximum retrospective premium obligation from an investment grade rated financial institution, or
- obtain insurance to cover its retrospective premium obligation.

Non-Nuclear Property Insurance

Our conventional property insurance provides coverage of $1.0 billion per occurrence for Certified acts of terrorism as defined under the 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.

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13 Derivatives and Fair Value Measurements

Use of Derivative Instruments

Nature of Our Business and Associated Risks

Our business activities primarily include our Generation, NewEnergy, regulated electric and gas businesses. Our Generation and NewEnergy businesses include:

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

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

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

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

Objectives and Strategies for Using Derivatives

Risk Management Activities

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

- fixing the price for a portion of anticipated future electricity sales from our generation operations,
- fixing the price of a portion of anticipated fuel purchases for the operation of our power plants,
- fixing the price for a portion of anticipated energy purchases to supply our load-serving customers, and

managing our exposure to interest rate risk and foreign currency exchange risks.

Non-Risk Management Activities

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

- optimizing the margin on surplus electricity generation and load positions and surplus fuel supply and demand positions,
- price discovery and verification, and
- deploying limited risk capital in an effort to generate returns.

Accounting for Derivative Instruments

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

Accounting Designation

We must evaluate new and existing transactions and agreements to determine whether they meet the definition of a derivative, for which there are several possible accounting treatments. The permissible accounting treatments include:

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

Mark-to-market is required as the default accounting treatment for all derivatives unless they qualify, and we specifically designate them, for one of the other accounting treatments. Derivatives designated for any of the elective accounting treatments must meet specific, restrictive criteria, both at the time of designation and on an ongoing basis.

We 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 cannot subsequently change the election and treat the contract as a derivative using mark-to-market or hedge accounting.

Cash Flow Hedging

We generally elect cash flow hedge accounting for most of the derivatives that we use to hedge market price risk for our physical energy delivery activities because hedge accounting more closely aligns the timing of earnings recognition and cash flows

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for the underlying business activities. Management monitors the potential impacts of commodity price changes and, where appropriate, may enter into or close out (via offsetting transactions) derivative transactions designated as cash flow hedges.

Commodity Cash Flow Hedges

We have designated fixed-price forward contracts as cash-flow hedges of forecasted sales of energy, fuel and other related commodities and forecasted purchases of fuel and energy for the years 2012 through 2017. We had net unrealized pre-tax losses on these cash-flow hedges recorded in "Accumulated other comprehensive loss" of $652.7 million at December 31, 2011 and $388.0 million at December 31, 2010.

We expect to reclassify $392.6 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, 2011. However, the actual amount reclassified into earnings could vary from the amounts recorded at December 31, 2011, due to future changes in market prices.

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

Year ended December 31,	**2011**	**2010**	**2009**
		(In millions)	
Pre-tax losses	**$ (4.0)**	$ (0.3)	$ (241.0)

Interest Rate Swaps Designated as Cash Flow Hedges

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

Accumulated other comprehensive loss includes net unrealized pre-tax gains on interest rate cash-flow hedges of prior debt issuances totaling $8.9 million at December 31, 2011 and $10.1 million at December 31, 2010. We expect to reclassify $0.1 million of pre-tax net losses on these cash-flow hedges from "Accumulated other comprehensive loss" into "Interest expense" during the next twelve months. We had no hedge ineffectiveness on these swaps.

During the third quarter of 2011, a subsidiary of Constellation Energy entered into forward-starting interest rate swap contracts to manage a portion of our interest rate exposure for anticipated long-term borrowings to finance our solar projects. The swaps have contract amounts that total $30.6 million with an average interest rate of 3.6% and expire in 2027. At December 31, 2011, the fair value of these swap contracts was an unrealized pre-tax loss of $3.6 million.

Fair Value Hedging

We elect fair value hedge accounting for a limited portion of our derivative contracts including certain interest rate swaps, certain forward contracts, and swaps associated with natural gas fuel in storage. The objectives for electing fair value hedging in these situations are to manage our exposure to changes in the fair value of our assets and liabilities, 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.

As of December 31, 2011, we have interest rate swaps qualifying as fair value hedges relating to $550 million of our fixed-rate debt maturing in 2015, and converted this notional amount of debt to floating-rate. The fair value of these hedges was an unrealized gain of $43.8 million at December 31, 2011.

As of December 31, 2010, we had interest rate swaps qualifying as fair value hedges relating to $400 million of our fixed-rate debt. The fair value of these hedges was an unrealized gain of $35.7 million at December 31, 2010.

We recorded the fair value of these hedges 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.

In January 2011, we terminated $200 million of these interest rate swaps as a result of retiring all of our fixed-rate debt maturing in 2012 and received $13.8 million in cash.

During February 2011, we entered into interest rate swaps qualifying as fair value hedges related to $350 million of our fixed rate debt maturing in 2015, and converted this notional amount of debt to floating rate. We also entered into $150 million of interest rate swaps related to our fixed rate debt maturing in 2020 that do not qualify as fair value hedges, which are discussed under *Mark-to-Market* below.

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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,	2011	2010	2009
		(In millions)	
Cash-flow hedges	**$ (132.4)**	$ (91.3)	$ 11.3
Fair value hedges	**(0.7)**		23.9
Total	**$ (133.1)**	$ (91.3)	$ 35.2

The ineffectiveness in the table above excludes pre-tax gains of $5.8 million related to the change in our fair value hedges excluded from hedge ineffectiveness for the year ended December 31, 2011. We did not have any gains excluded from the above table in 2010 and 2009. We did not recognize any gain or loss related to the change in our fair value hedges excluded from hedge ineffectiveness during the years ended December 31, 2011, 2010, and 2009.

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 activities:

- our competitive retail gas customer supply activities, which are managed using economic hedges that we have not designated as cash-flow hedges in order to match the timing of recognition of the earnings impacts of those activities to the greatest extent permissible,
- economic hedges of activities that require accrual accounting for which the related hedge requires mark-to-market accounting, and
- during February 2011, we entered into interest rate swaps related to $150 million of our fixed rate debt maturing in 2020, and converted this notional amount of debt to floating rate. However, these interest rate swaps do not qualify as fair value hedges and will be marked to market through earnings.

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. We have recorded a $14.8 million pre-tax origination gain related to one transaction in 2011. We recorded no origination gains during 2010 or 2009.

Termination or Restructuring of Commodity Derivative Contracts

We may terminate or restructure commodity derivative 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. We had no such transactions in 2011, 2010 and 2009.

Quantitative Information About Derivatives and Hedging Activities

Background

Effective January 1, 2009, we adopted an accounting standard that addresses disclosures about derivative instruments and hedging activities. This standard does not change the accounting for derivatives; rather, it requires expanded disclosure about derivative instruments and hedging activities regarding:

- the ways in which an entity uses derivatives,
- the accounting for derivatives and hedging activities, and
- the impact that derivatives have (or could have) on an entity's financial position, financial performance, and cash flows.

Balance Sheet Tables

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

The following tables provide information about the risks we manage using derivatives. These tables only include derivatives and do not reflect the price risks we are hedging that arise from physical assets or nonderivative accrual contracts within our Generation and NewEnergy businesses.

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

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

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

As of December 31, 2011	Derivatives Designated as Hedging Instruments for Accounting Purposes		Derivatives Not Designated As Hedging Instruments for Accounting Purposes		All Derivatives Combined	
Contract type	**Asset Values (3)**	**Liability Values (4)**	**Asset Values (3)**	**Liability Values (4)**	**Asset Values (3)**	**Liability Values (4)**
			(In millions)			
Power contracts	$ 1,617.2	$ (1,686.9)	$ 4,785.8	$ (5,105.9)	$ 6,403.0	$ (6,792.8)
Gas contracts	1,624.5	(2,108.4)	4,842.8	(4,858.1)	6,467.3	(6,966.5)
Coal contracts	34.0	(36.0)	73.0	(66.3)	107.0	(102.3)
Other commodity contracts (1)			153.8	(144.2)	153.8	(144.2)
Interest rate contracts	43.9	(3.6)	55.1	(49.0)	99.0	(52.6)
Foreign exchange contracts			10.5	(2.8)	10.5	(2.8)
Equity contracts			0.2		0.2	
Total gross fair values	$ 3,319.6	$ (3,834.9)	$ 9,921.2	$ (10,226.3)	$ 13,240.8	$ (14,061.2)
Netting arrangements (5)					(12,989.5)	12,989.5
Cash collateral					(167.2)	23.8
Net fair values					$ 84.1	$ (1,047.9)
Net fair value by balance sheet line item:						
Accounts receivable (2)					$ (533.1)	
Derivative assets current					357.9	
Derivative assets noncurrent					259.3	
Derivative liabilities current						(779.5)
Derivative liabilities noncurrent						(268.4)
Total Derivatives					$ 84.1	$ (1,047.9)

(1) *Other commodity contracts include oil, freight, emission allowances, renewable energy credits, and weather contracts.*

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

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

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

(5) *Represents the effect of legally enforceable master netting agreements.*

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As of December 31, 2010	Derivatives Designated as Hedging Instruments for Accounting Purposes		Derivatives Not Designated As Hedging Instruments for Accounting Purposes		All Derivatives Combined	
Contract type	**Asset Values (3)**	**Liability Values (4)**	**Asset Values (3)**	**Liability Values (4)**	**Asset Values (3)**	**Liability Values (4)**
			(In millions)			
Power contracts	$ 1,167.9	$ (1,362.8)	$ 6,795.0	$ (7,166.5)	$ 7,962.9	$ (8,529.3)
Gas contracts	1,902.3	(1,832.8)	3,390.1	(3,155.3)	5,292.4	(4,988.1)
Coal contracts	97.0	(48.6)	266.0	(259.7)	363.0	(308.3)
Other commodity contracts (1)			61.4	(61.6)	61.4	(61.6)
Interest rate contracts	35.7		34.4	(35.7)	70.1	(35.7)
Foreign exchange contracts			11.0	(8.4)	11.0	(8.4)
Total gross fair values	$ 3,202.9	$ (3,244.2)	$ 10,557.9	$ (10,687.2)	$ 13,760.8	$ (13,931.4)
Netting arrangements (5)					(12,955.5)	12,955.5
Cash collateral					(28.4)	0.6
Net fair values					$ 776.9	$ (975.3)
Net fair value by balance sheet line item:						
Accounts receivable (2)					$ (16.4)	
Derivative assets current					534.4	
Derivative assets noncurrent					258.9	
Derivative liabilities current						(622.3)
Derivative liabilities noncurrent						(353.0)
Total Derivatives					$ 776.9	$ (975.3)

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

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

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

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

(5) *Represents the effect of legally enforceable master netting agreements.*

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

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

Gain and (Loss) Tables

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

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

The tables only include this information for derivatives and do not reflect the related gains or losses that arise from generation and generation-related assets, nonderivative accrual contracts, or NPNS contracts within our Generation and NewEnergy businesses, other than fair value hedges, for which

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we separately show the gain or loss on the hedged asset or liability. As a result, for mark-to-market and cash-flow hedge derivatives, these tables only reflect the impact of derivatives themselves and therefore do not necessarily include all of the income statement impacts of the transactions for which derivatives are used to manage risk. For a more complete discussion of how derivatives affect our financial performance, see our accounting policy for *Revenues, Fuel and Purchased Energy Expenses*, and *Derivatives and Hedging Activities* in *Note 1*.

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

Cash Flow Hedges *Year Ended December 31,*

	Gain (Loss) Recorded in AOCI			**Statement of Income (Loss) Line**	**Gain (Loss) Reclassified from AOCI into Earnings**			**Ineffectiveness Gain (Loss) Recorded in Earnings**		
Contract type:	**2011**	**2010**	**2009**	**Item**	**2011**	**2010**	**2009**	**2011**	**2010**	**2009**
				(In millions)						
Hedges of forecasted sales:				Nonregulated revenues						
Power contracts	$ 162.3	$ 144.5	$ 362.5		$ 19.2	$ (165.8)	$ (180.6)	$ 70.9	$ 8.9	$ 77.5
Gas contracts	63.5	(59.1)	(65.1)		198.5	90.8	(67.3)	(49.6)	(0.3)	6.3
Coal contracts			10.0				(229.9)			
Other commodity contracts (1)			6.8			(0.7)	(0.4)			(6.2)
Interest rate contracts			(0.3)				(0.3)			
Foreign exchange contracts			2.5			(1.0)	(1.1)			
Total gains (losses)	$ 225.8	$ 85.4	$ 316.4	Total included in nonregulated revenues	$ 217.7	$ (76.7)	$ (479.6)	$ 21.3	$ 8.6	$ 77.6
Hedges of forecasted purchases:				Fuel and purchased energy expense						
Power contracts	$ (295.5)	$ (377.4)	$ (1,056.0)		$ (476.7)	$ (1,036.1)	$ (1,905.3)	$ (52.0)	$ (40.7)	$ (42.2)
Gas contracts	(471.6)	(141.5)	103.7		(51.8)	216.5	165.8	(102.5)	(64.3)	(15.2)
Coal contracts	(11.8)	65.9	(77.7)		22.4	(34.6)	(187.6)	0.8	4.9	(8.9)
Other commodity contracts (2)		(0.2)	(12.3)			(0.3)	8.2		0.2	
Foreign exchange contracts										
Total losses	$ (778.9)	$ (453.2)	$ (1,042.3)	Total included in fuel and purchased energy expense	$ (506.1)	$ (854.5)	$ (1,918.9)	$ (153.7)	$ (99.9)	$ (66.3)
Hedges of interest rates:				Interest expense						
Interest rate contracts	(3.6)				1.2	4.3	0.6			
Total (losses) gains	$ (3.6)	$	$	Total included in interest expense	$ 1.2	$ 4.3	$ 0.6	$	$	$

Grand total (losses) gains	$ (556.7)	$ (367.8)	$ (725.9)		$ (287.2)	$ (926.9)	$ (2,397.9)	$ (132.4)	$ (91.3)	$ 11.3

(1) *Other commodity sale contracts include oil and freight contracts.*

(2) *Other commodity purchase contracts include freight and emission allowances.*

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The following table presents gains and losses on derivatives designated as fair value hedges and, separately, the gains and losses on the hedged item. As discussed earlier, we record the unrealized gains and losses on fair value hedges as well as changes in the fair value of the hedged asset or liability in earnings as they occur. The difference between these amounts represents hedge ineffectiveness.

Fair Value Hedges		***Year Ended December 31,***					
	Statement of Income	**Amount of Gain (Loss) Recognized in Income on Derivative**			**Amount of Gain (Loss) Recognized in Income on Hedged Item**		
Contract type:	**(Loss) Line Item**	**2011**	**2010**	**2009**	**2011**	**2010**	**2009**
		(In millions)					
Gas contracts	Nonregulated revenues	$ 23.4	$	$ 40.6	$ (15.9)	$	$ (16.7)
Interest rate contracts	Interest expense	32.9	18.0	(0.1)	(32.8)	(15.6)	0.7
Total gains (losses)		$ 56.3	$ 18.0	$ 40.5	$ (48.7)	$ (15.6)	$ (16.0)

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

Mark-to-Market Derivatives		***Year Ended December 31,***		
	Statement of Income (Loss) Line	**Amount of Gain (Loss) Recorded in Income on Derivative**		
Contract type:	**Item**	**2011**	**2010**	**2009**
		(In millions)		
Commodity contracts:				
Power contracts	Nonregulated revenues	$ (51.4)	$ (26.2)	$ 250.9
Gas contracts	Nonregulated revenues	(224.3)	41.4	(360.0)
Coal contracts	Nonregulated revenues	(9.2)	13.3	14.0
Other commodity contracts (1)	Nonregulated revenues	(4.4)	(15.4)	(11.7)
Coal contracts	Fuel and purchased energy expense			(109.8)
Interest rate contracts	Nonregulated revenues	1.6	(2.3)	(27.2)
Interest rate contracts	Interest expense	5.2		
Foreign exchange contracts	Nonregulated revenues	0.4	(1.2)	7.6
Equity contracts	Nonregulated revenues	(0.4)		
Total gains (losses)		$ (282.5)	$ 9.6	$ (236.2)

(1) *Other commodity contracts include oil, freight, weather, renewable energy credits, and emission allowances.*

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

Other Comprehensive Loss into earnings.

Volume of Derivative Activity

The volume of our derivatives activity is directly related to the fundamental nature and scope of our business and the risks we manage. We own or control electric generating facilities, which exposes us to both power and fuel price risk; we serve electric and gas wholesale and retail customers within our NewEnergy business, which exposes us to electricity and natural gas price risk; and we provide risk management services and engage in trading activities, which can expose us to a variety of commodity price risks. In order to manage the risks associated with these activities, we are required to be an active participant in the energy markets, and we routinely employ derivative instruments to conduct our business.

Derivative instruments provide an efficient and effective way to conduct our business and to manage the associated risks. As such, we use derivatives in the following ways:

- We manage our generating resources and NewEnergy business based upon established policies and limits, and we use derivatives to establish a portion of our hedges and to adjust the level of our hedges from time to time.

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We engage in trading activities which enable us to execute hedging transactions in a cost-effective manner. We manage those activities based upon various risk measures, including position limits, economic value at risk (EVaR) and value at risk (VaR), and we use derivatives to establish and maintain those activities within the prescribed limits.

We also use derivatives to execute, control, and reduce the overall level of our trading positions and risk as well as to manage a portion of our interest rate risk associated with debt and our foreign currency risk from non-dollar denominated transactions.

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

The volume information is not a complete representation of our market price risk because it only includes derivative contracts. Accordingly, these tables do not present a complete picture of our overall net economic exposure, and should not be interpreted as an indication of open or unhedged commodity positions, because the use of derivatives is only one of the means by which we engage in and manage the risks of our business. For example, the table does not include power or fuel quantities and risks arising from our physical assets, non-derivative contracts, and forecasted transactions that we manage using derivatives; a portion of these volumes reduces those risks.

The tables also do not include volumes of commodities under nonderivative contracts that we use to serve customers or manage our risks. Our actual net economic exposure from our generating facilities and NewEnergy activities is reduced by derivatives, and the exposure from our trading activities is managed and controlled through the risk measures discussed above. Therefore, the information in the tables below is only an indication of that portion of our business that we manage through derivatives and serves primarily to identify the extent of our derivatives activities and the types of risks that they are intended to manage.

We have computed the derivative volumes for commodities by aggregating the absolute value of net positions within commodities for each year. This provides an indication of the level of derivatives activity, but it does not indicate either the direction of our position (long or short), or the overall size of our position. We believe this presentation gives an appropriate indication of the level of derivatives activity without unnecessarily revealing the size and direction of our derivatives positions. The disclosure of such information could limit the effectiveness and profitability of our business activities.

The volume information for commodity derivatives represents "delta equivalent" quantities, not gross notional amounts. We believe that the delta equivalent quantity is the most relevant measure of the volume associated with commodity derivatives. The delta-equivalent quantity represents a risk-adjusted notional quantity for each contract that takes into account the probability that an option will be exercised. For interest rate contracts and foreign currency contracts we have presented the notional amounts of such contracts in the table below.

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The following tables present the volume of our derivative activities as of December 31, 2011 and 2010, shown by contractual settlement year.

Quantities (1) Under Derivative Contracts							*As of December 31, 2011*
Contract Type (Unit)	**2012**	**2013**	**2014**	**2015**	**2016**	**Thereafter**	**Total**
				(In millions)			
Power (MWH)	20.8	13.0	0.9	0.4	1.7	0.4	37.2
Gas (mmBTU)	263.6	47.7	49.4	18.4	1.8	1.8	382.7
Coal (Tons)	0.8	0.7					1.5
Oil (BBL)	0.1	0.3	0.1				0.5
Emission Allowances (Tons)	0.1	0.1					0.2
Renewable Energy Credits (Number of credits)	0.3	0.3	0.3	0.3	0.3	0.2	1.7
Equity contracts (Number of shares)			0.1	0.1			0.2
Interest Rate Contracts	$ 6.7	$ 515.2	$ 173.0	$ 800.0	$ 387.0	$ 255.6	$ 2,137.5
Foreign Exchange Rate Contracts	$ 44.1	$ 8.0	$ 16.8	$ 15.5	$	$	$ 84.4

Quantities (1) Under Derivative Contracts							*As of December 31, 2010*
Contract Type (Unit)	**2011**	**2012**	**2013**	**2014**	**2015**	**Thereafter**	**Total**
				(In millions)			
Power (MWH)	21.2		3.8	4.2	2.3	0.2	31.7
Gas (mmBTU)	175.3	90.1	80.2	64.7	24.1		434.4
Coal (Tons)	4.4	2.5	0.1				7.0
Oil (BBL)	0.2	0.1	0.1				0.4
Emission Allowances (Tons)	1.5						1.5
Renewable Energy Credits (Number of credits)	0.4	0.3	0.3	0.3	0.3	0.7	2.3
Interest Rate Contracts	$ 639.4	$ 490.7	$ 941.8	$ 405.0	$ 460.0	$ 175.0	$ 3,111.9
Foreign Exchange Rate Contracts	$ 48.7	$ 8.7	$ 16.8	$ 16.8	$ 15.5	$	$ 106.5

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

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

Credit-Risk Related Contingent Features

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

The following tables present information related to these derivatives at December 31, 2011 and 2010.

We present the gross fair value of derivatives in a net liability position that have credit-risk-related contingent features in the first column in the table below. This gross fair value amount represents only the out-of-the-money contracts containing such features that are not fully collateralized by cash on a stand-alone basis. Thus, this amount does not reflect the offsetting fair value of in-the-money contracts under legally-binding master netting agreements with the same counterparty, as shown in the second column in the table. These in-the-money contracts would offset the amount of any gross liability that could be required to be collateralized, and as a result, the actual potential collateral requirements would be based upon the net fair value of derivatives containing such features, not the gross amount. The amount of any possible contingent collateral for such contracts in the event of a downgrade would be further reduced to the extent that we have already posted collateral related to the net liability.

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

Credit-Risk Related Contingent Feature ***As of December 31, 2011***

Gross Fair Value of Derivative Contracts Containing This Feature (1)	Offsetting Fair Value of In-the-Money Contracts Under Master Netting Agreements (2)	Net Fair Value of Derivative Contracts Containing This Feature (3)	Amount of Posted Collateral (4)	Contingent Collateral Obligation (5)
		(In billions)		
$3.3	$ (2.4)	$ 0.9	$ 0.6	$ 0.2

Credit-Risk Related Contingent Feature ***As of December 31, 2010***

Gross Fair Value of Derivative Contracts Containing This Feature (1)	Offsetting Fair Value of In-the-Money Contracts Under Master Netting Agreements (2)	Net Fair Value of Derivative Contracts Containing This Feature (3)	Amount of Posted Collateral (4)	Contingent Collateral Obligation (5)
		(In billions)		
$4.6	$ (3.7)	$ 0.9	$ 0.7	$ 0.1

(1) *Amount represents the gross fair value of out-of-the-money derivative contracts containing credit-risk-related contingent features that are not fully collateralized by posted cash collateral on an individual, contract-by-contract basis ignoring the effects of master netting agreements.*

(2) *Amount represents the offsetting fair value of in-the-money derivative contracts under legally-enforceable master netting agreements with the same counterparty, which reduces the amount of any liability for which we potentially could be required to post collateral.*

(3) *Amount represents the net fair value of out-of-the-money derivative contracts containing credit-risk related contingent features after considering the mitigating effects of offsetting positions under master netting arrangements and reflects the actual net liability upon which any potential contingent collateral obligations would be based.*

(4) *Amount includes cash collateral posted of $23.8 million and letters of credit of $563.6 million at December 31, 2011 and cash collateral posted of $0.6 million and letters of credit of $656.9 million at December 31, 2010.*

(5) *Amounts represent the additional collateral that we could be required to post with counterparties, including both cash collateral and letters of credit, in the event of a credit downgrade to below investment grade after giving consideration to offsetting derivative and non-derivative positions under master netting agreements.*

Concentrations of Derivative-Related Credit Risk

We discuss our concentrations of credit risk, including derivative-related positions, in *Note 1*. At December 31, 2011, we had credit exposure to two counterparties, both large investment grade power cooperatives, equal to 29% of our total credit exposure.

Fair Value Measurements

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 using assumptions that market participants would use in pricing the asset or liability.

We present all derivatives recorded at fair value net with the associated fair value cash collateral. This presentation of the net position reflects our credit exposure for our on-balance sheet positions but excludes the impact of any off-balance sheet positions and collateral. Examples of off-balance sheet positions and collateral include in-the-money accrual contracts for which the right of offset exists in the event of default and letters of credit. We discuss our letters of credit in more detail in *Note 8*.

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Recurring Measurements

Our assets and liabilities measured at fair value on a recurring basis consist of the following (immaterial for BGEs assets and liabilities):

	As of December 31, 2011	
	Assets	Liabilities
	(In millions)	
Cash equivalents	$ 344.2	$
Debt and equity securities	39.8	
Derivative instruments:		
Classified as derivative assets and liabilities:		
Current	357.9	(779.5)
Noncurrent	259.3	(268.4)
Total classified as derivative assets and liabilities	617.2	(1,047.9)
Classified as accounts receivable (1)	(533.1)	
Total derivative instruments	84.1	(1,047.9)
Total recurring fair value measurements	$ 468.1	$ (1,047.9)

(1)
Represents the unrealized fair value of exchange traded derivatives, exclusive of cash margin posted.

	As of December 31, 2010	
	Assets	Liabilities
	(In millions)	
Cash equivalents	$ 1,545.4	$
Debt and equity securities	47.8	
Derivative instruments:		
Classified as derivative assets and liabilities:		
Current	534.4	(622.3)
Noncurrent	258.9	(353.0)
Total classified as derivative assets and liabilities	793.3	(975.3)
Classified as accounts receivable (1)	(16.4)	
Total derivative instruments	776.9	(975.3)
Total recurring fair value measurements	$ 2,370.1	$ (975.3)

(1)
Represents the unrealized fair value of exchange traded derivatives, exclusive of cash margin posted.

Cash equivalents represent money market funds which are included in "Cash and cash equivalents" in the Consolidated Balance Sheets. Debt securities primarily represent available-for-sale investments in private companies included in "Other assets" in the Consolidated Balance Sheets. Equity securities primarily represent mutual fund investments which are included in "Other assets" in the Consolidated Balance Sheets. Derivative instruments represent unrealized amounts related to all derivatives. We classify exchange-listed derivatives as part of "Accounts Receivable" in our Consolidated Balance Sheets. We classify the remainder of our derivatives as "Derivative assets" or "Derivative liabilities" in our Consolidated Balance Sheets.

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The tables below set 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, 2011 and 2010. We disaggregate our net derivative assets and liabilities by separating each individual derivative contract that is in-the-money from each contract that is out-of-the-money regardless of master netting agreements and collateral. As a result, the gross "asset" and "liability" amounts in each of the three fair value levels far exceed our actual economic exposure to commodity price risk and credit risk. The objective of these tables 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. Therefore, 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, 2011	**Level 1**	**Level 2**	**Level 3**	**Netting and Cash Collateral (1)**	**Total Net Fair Value**
			(In millions)		
Cash equivalents	$ 344.2	$	$	$	$ 344.2
Debt and equity securities	30.5		9.3		39.8
Derivative assets:					
Power contracts		5,835.2	567.8		
Gas contracts	430.5	5,371.2	665.6		
Coal contracts		106.8	0.2		
Other commodity contracts	2.0	35.2	116.6		
Interest rate contracts	48.2	50.8			
Foreign exchange contracts		10.5			
Equity contracts			0.2		
Total derivative assets	480.7	11,409.7	1,350.4	(13,156.7)	84.1
Derivative liabilities:					
Power contracts		(6,175.0)	(617.8)		
Gas contracts	(450.4)	(6,046.9)	(470.3)		
Coal contracts		(101.6)	(0.7)		
Other commodity contracts	(2.2)	(25.2)	(116.8)		
Interest rate contracts	(47.9)		(3.6)		
Foreign exchange contracts		(2.8)			
Total derivative liabilities	(500.5)	(12,351.5)	(1,209.2)	13,013.3	(1,047.9)
Net derivative position	(19.8)	(941.8)	141.2	(143.4)	(963.8)
Total	$ 354.9	$ (941.8)	$ 150.5	$ (143.4)	$ (579.8)

(1) *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, 2011, we included $167.2 million of cash collateral held and $23.8 million of cash collateral posted (excluding margin posted on exchange traded derivatives) in netting amounts in the above table.*

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At December 31, 2010	Level 1	Level 2	Level 3	Netting and Cash Collateral (1)	Total Net Fair Value
			(In millions)		
Cash equivalents	$ 1,545.4	$	$	$	$ 1,545.4
Debt and equity securities	43.7		4.1		47.8
Derivative assets:					
Power contracts		7,509.6	453.3		
Gas contracts	63.9	5,113.3	115.2		
Coal contracts		355.6	7.4		
Other commodity contracts	6.6	54.8			
Interest rate contracts	33.1	37.0			
Foreign exchange contracts		11.0			
Total derivative assets	103.6	13,081.3	575.9	(12,983.9)	776.9
Derivative liabilities:					
Power contracts		(7,758.2)	(771.1)		
Gas contracts	(72.7)	(4,910.3)	(5.1)		
Coal contracts		(307.4)	(0.9)		
Other commodity contracts	(7.1)	(54.5)			
Interest rate contracts	(35.7)				
Foreign exchange contracts		(8.4)			
Total derivative liabilities	(115.5)	(13,038.8)	(777.1)	12,956.1	(975.3)
Net derivative position	(11.9)	42.5	(201.2)	(27.8)	(198.4)
Total	$ 1,577.2	$ 42.5	$ (197.1)	$ (27.8)	$ 1,394.8

(1) *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, 2010, we included $28.4 million of cash collateral held and $0.6 million of cash collateral posted (excluding margin posted on exchange traded derivatives) in netting amounts in the above table.*

The factors that cause changes in the gross components of the derivative amounts in the tables above are unrelated to the existence or level of actual market or credit risk from our operations. We describe the primary factors that change the gross components below.

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

Cash equivalents consist of exchange-traded money market funds, which are valued by multiplying unadjusted quoted prices in active markets by the quantity of the asset and are classified within Level 1.

Debt securities consist of Series A Preferred Stock in two privately owned companies, which are valued based on the purchase price of the security and are classified within Level 3.

Equity securities consist of mutual funds and common shares in public companies, which are valued by multiplying unadjusted quoted prices in active markets by the quantity of the asset and are classified within Level 1.

Derivative instruments include exchange-traded and bilateral contracts. Exchange-traded derivative contracts include futures and options. Bilateral derivative contracts include swaps, forwards, options and structured transactions. We have classified derivative contracts within the fair value hierarchy as follows:

Exchange-traded derivative contracts valued by multiplying unadjusted quoted prices in active markets by the quantity of the asset or liability are classified within Level 1.

Exchange-traded derivative contracts valued using pricing inputs based upon market quotes or market transactions are classified within Level 2. These contracts generally trade in less active markets (i.e., for certain contracts the exchange sets the closing price, which may not be reflective of an actual trade).

Bilateral derivative contracts where observable inputs are available for substantially the full term and value of the asset or liability are classified within Level 2.

Bilateral derivative contracts with a lower availability of pricing information are classified in Level 3. In addition, structured transactions, such as certain options, may require us to use internally developed model inputs, which might not be observable in or corroborated by

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the market, to determine fair value. When such unobservable inputs have more than an insignificant impact on the measurement of fair value, we classify the instrument within Level 3.

During 2011, there were no significant transfers of derivatives between Level 1 and Level 2 of the fair value hierarchy.

We utilize models based upon the income approach to measure the fair value of derivative contracts classified as Level 2 or 3. Generally, we use similar models to value similar instruments. In order to determine fair value, we utilize various inputs and factors including market data and assumptions that market participants would use in pricing assets or liabilities as well as assumptions about the risks inherent in the inputs to the valuation technique. The inputs and factors include:

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

The primary input to our valuation models is the forward commodity curve for the respective instrument. Forward commodity curves are derived from published exchange transaction prices, executed bilateral transactions, broker quotes, and other observable or public data sources. The relevant forward commodity curve used to value each of our derivatives will depend on a number of factors including commodity type, location, and expected delivery period. Price volatility would vary by commodity and location. When appropriate, we discount future cash flows using risk free interest rates with adjustments to reflect the credit quality of each counterparty for assets and our own credit quality for liabilities.

We also record valuation adjustments to reflect uncertainty associated with certain estimates inherent in the determination of the fair value of derivative assets and liabilities. The effect of these uncertainties is not incorporated in market price information of other market-based estimates used to determine fair value of our mark-to-market energy contracts.

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.

- Unobservable input valuation adjustment this adjustment is 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. 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 thus we 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. 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

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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. Thus, even though we are required 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, which predominantly relate to power contracts:

	Year Ended December 31, 2011	2010
	(In millions)	
Balance at beginning of period	**$ (197.1)**	$ (291.5)
Realized and unrealized (losses) gains:		
Recorded in income	**265.0**	157.1
Recorded in other comprehensive income	**28.2**	95.2
Purchases	**(3.0)**	
Sales		
Issuances	**24.8**	
Settlements		
Net purchases, sales, issuances, and settlements (1)	**21.8**	(65.6)
Transfers into Level 3 (2)	**81.6**	73.6
Transfers out of Level 3 (2)	**(49.0)**	(165.9)
Balance at end of year	**$ 150.5**	$ (197.1)
Change in unrealized gains recorded in income relating to derivatives still held at end of period	**$ 51.3**	$ 189.6

(1) *Effective January 1, 2011, we are required to present separately purchases, sales, issuances, and settlements.*

(2) *For purposes of this reconciliation, we assumed transfers into and out of Level 3 occurred on the last day of the quarter.*

We have defined the categories of purchases, sales, issuances, and settlements to include the inflow or outflow of value as follows:

- purchases includes the acquisition of pre-existing derivative contracts,
- sales includes the sale or assignment of pre-existing derivative contracts,
- issuances includes the acquisition of derivative contracts and debt securities at inception, and
- settlements includes the termination of existing derivative contracts prior to normal maturity or settlement.

During 2011, we had purchases related to our business acquisition and issuances related to premiums paid for option contracts and payments for transmission congestion contracts.

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 previously 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 tables below sets forth our assets and liabilities that were measured at fair value on a nonrecurring basis during the year ended December 31, 2011 and 2010:

	Fair Value at December 31, 2011	Losses for the year ended December 31, 2011
	(In millions)	
Investment in CENG	$ 2,150.4	$ 824.2
Other investments:		
Qualifying facilities coal	22.5	36.7
Qualifying facilities biomass	24.6	23.3
Qualifying facilities solar		6.8
Total other investments	47.1	66.8
Total	$ 2,197.5	$ 891.0

During the quarter ended December 31, 2011, we recorded other-than-temporary impairment charges of $891.0 million on

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our equity method investments including CENG and certain of our qualifying facilities. These fair value measurements included significant unobservable inputs, and, as such, the entire amounts of the measurements were classified as Level 3. We discuss these impairment charges, including the inputs and valuation techniques used to estimate the fair value of these equity method investments, in more detail in *Note 2*.

	Fair Value at September 30, 2010	Fair Value at December 31, 2010	Losses for the year ended December 31, 2010
		(In millions)	
Investment in CENG	$ 2,970.4	$ N/A	$ 2,275.0
Other investments:			
UNE		N/A	143.4
Qualifying facilities coal	36.7	N/A	50.0
Qualifying facilities hydroelectric	N/A	14.8	8.4
Total other investments	36.7	14.8	201.8
Total	$ 3,007.1	$ 14.8	$ 2,476.8

During the quarter ended September 30, 2010, we recorded other-than-temporary impairment charges of $2,468.4 million on our equity method investments including CENG, UNE, and three coal-fired generating facilities located in California. Additionally, during the quarter ended December 31, 2010, we recorded an other-than-temporary impairment charge of $8.4 million on one of our equity investments that own a hydroelectric generating facility in California. These fair value measurements included significant unobservable inputs, and, as such, the entire amounts of the measurements were classified as Level 3. We discuss these impairment charges, including the inputs and valuation techniques used to estimate the fair value of these equity method investments, in more detail in *Note 2*.

There were no nonrecurring measurements in 2009.

Fair Value of Financial Instruments

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

At December 31,	**2011**		**2010**	
	Carrying Amount	**Fair Value**	**Carrying Amount**	**Fair Value**
		(In millions)		
Investments and other assets Constellation Energy	**$ 146.8**	**$ 146.8**	$ 135.7	$ 136.2
Fixed-rate long-term debt:				
Constellation Energy (including BGE)	**4,132.5**	**4,702.8**	4,229.3	4,518.4
BGE	**2,361.9**	**2,636.8**	2,143.6	2,301.8
Variable-rate long-term debt:				
Constellation Energy (including BGE)	**892.3**	**892.3**	528.7	528.7
BGE				

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

cash and cash equivalents, net accounts receivable, restricted cash, 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.

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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, stock units, deferred cash and equity to officers, key employees, and members of the Board of Directors. In May 2010, shareholders approved Constellation Energy's Amended and Restated 2007 Long-Term Incentive Plan, including an increase in the number of shares available for issuance by 9,000,000. 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 Amended and Restated 2007 Long-Term Incentive Plan. At December 31, 2011, there were 10,143,863 shares available for issuance under the 2007 Long-Term Incentive Plan. At December 31, 2011, we had stock options, restricted stock, performance units 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 2011, 2010, and 2009 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:

	2011	2010	2009
Risk-free interest rate	**1.69%**	1.87%	1.95%
Expected life (in years)	**4.0**	4.0	4.0
Expected market price volatility factor	**27.7%**	32.5%	37.8%
Expected dividend yield	**3.17%**	2.74%	4.83%

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, information on the volatility of an identified group of peer companies, 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:

	2011		2010		2009	
	Shares	Weighted-Average Exercise Price	Shares	Weighted-Average Exercise Price	Shares	Weighted-Average Exercise Price
			(Shares in thousands)			
Outstanding, beginning of year	**9,070**	**$ 43.43**	8,146	$ 44.36	6,058	$ 59.99
Granted with exercise prices at fair market value	**2,244**	**30.25**	1,468	35.07	3,511	20.14
Exercised	**(474)**	**23.59**	(235)	23.53	(83)	31.07
Forfeited/expired	**(184)**	**56.58**	(309)	43.41	(1,340)	52.41
Outstanding, end of year	**10,656**	**$ 41.31**	9,070	$ 43.43	8,146	$ 44.36
Exercisable, end of year	**6,539**	**$ 49.15**	5,316	$ 52.65	4,114	$ 55.81
Weighted-average fair value per share of options granted with exercise prices at fair market value		**$ 5.20**		$ 7.60		$ 4.24

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The following table summarizes additional information about stock options during 2011, 2010 and 2009:

	2011	2010	2009
	(In millions)		
Stock Option Expense Recognized	**$ 10.3**	$ 9.9	$ 14.2
Stock Options Exercised:			
Cash Received for Exercise Price	**11.2**	5.5	2.6
Intrinsic Value Realized by Employee	**5.9**	2.7	0.2
Realized Tax Benefit	**2.4**	1.1	0.1
Fair Value of Options that Vested	**52.4**	54.4	11.0

As of December 31, 2011, we had $4.1 million of unrecognized compensation cost related to the unvested portion of outstanding stock option awards, of which $3.1 million is expected to be recognized during 2012.

The following table summarizes additional information about stock options outstanding at December 31, 2011 (stock options in thousands):

	Outstanding		Exercisable		
Range of Exercise Prices	Stock Options	Aggregate Intrinsic Value	Stock Options	Aggregate Intrinsic Value	Weighted-Average Remaining Contractual Life
		(In millions)		*(In millions)*	*(In years)*
$ 0 - $ 20	2,524	$ 50.7	1,563	$ 31.4	7.2
$20 - $ 40	4,402	31.2	1,246	5.3	7.6
$40 - $ 60	2,362		2,362		3.2
$60 - $ 80	717		717		5.2
$80 - $100	651		651		6.1
	10,656	$ 81.9	6,539	$ 36.7	

Restricted Stock Awards

In addition to stock options, we issue service-based common stock that vests over periods ranging from one to five years and fully vested common stock units with sales restrictions ranging from approximately 10 months to 5 years. We account for these awards as equity awards, whereby we recognize the value of the market price of the underlying stock on the date of grant as compensation expense immediately for fully vested common stock units with sales restrictions or over the service period either ratably or in tranches (depending if the award has cliff or graded vesting) for service-based common stock.

We recorded compensation expense related to our restricted stock awards of $12.7 million in 2011, $9.5 million in 2010, and $16.7 million in 2009. The tax benefits received associated with our restricted awards were $9.4 million in 2011, $10.0 million in 2010, and $6.7 million in 2009.

Summarized share information for our restricted stock awards is as follows:

	2011	2010	2009
	(Shares in thousands)		
Outstanding, beginning of year	**1,080**	1,017	1,033
Granted	**622**	832	866
Released to participants	**(686)**	(713)	(701)
Canceled	**(48)**	(56)	(181)
Outstanding, end of year	**968**	1,080	1,017

Weighted-average fair value of restricted stock granted (per share)	**$ 30.27**	$ 34.83	$ 19.83
Total fair value of shares for which restriction has lapsed (in millions)	**$ 23.3**	$ 24.9	$ 16.5

As of December 31, 2011, we had $9.2 million of unrecognized compensation cost related to the unvested portion of outstanding restricted stock awards expected to be recognized within a 31-month period. At December 31, 2011, we have recorded in "Common shareholders' equity" approximately $17.2 million and approximately $18.6 million at December 31, 2010 for the unvested portion of service-based restricted stock granted from 2008 until 2011 to officers and other employees.

Performance-Based Units

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. We recognized compensation expense of $14.7 million in 2011, compensation expense of $6.2 million in 2010, and compensation expense of $1.5 million in 2009 for these awards. During the 12 months ended December 31, 2011, our 2008 performance-based unit awards vested and we paid $1.3 million. During the 12 months ended December 31, 2010, and 2009, no performance-based unit awards vested. As of December 31, 2011, we had $11.7 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 $1.1 million in 2011, $0.8 million in 2010, and $0.9 million in 2009 related to equity-based grants to members of the Board of Directors.

15 Merger and Acquisitions

Pending Merger with Exelon Corporation

On April 28, 2011, Constellation Energy entered into an Agreement and Plan of Merger with Exelon Corporation (Exelon). At closing, each issued and outstanding share of common stock of Constellation Energy will be cancelled and converted into the right to receive 0.93 shares of common stock of Exelon, and Constellation Energy will become a wholly owned subsidiary of Exelon.

The merger agreement contains certain termination rights for both Constellation Energy and Exelon. Under narrow specified circumstances in which the merger agreement is terminated and another acquisition proposal is accepted, Constellation Energy may be required to pay Exelon a termination fee of $200 million and Exelon may be required to pay Constellation Energy a termination fee of $800 million.

In connection with the proposed merger, Exelon and Constellation Energy offered numerous commitments, each of which is contingent upon completion of the merger, in support of their request for approval of the merger with the Maryland Public Service Commission (Maryland PSC). In addition, in December 2011, Exelon, Exelon Energy Delivery Company, LLC, Constellation Energy, and BGE entered into a settlement agreement with the State of Maryland, the Maryland Energy Administration, the City of Baltimore, and the Baltimore Building and Construction Trades Council, in which they agreed to several additional commitments contingent upon completion of the merger.

In January 2012, Exelon, Exelon Energy Delivery Company, LLC, Constellation Energy, and BGE entered into a settlement agreement with EDF Group and affiliates (EDF) in which, subject to the consummation of the merger with Exelon, the parties agreed to amendments to the operating agreement of CENG, an existing Administrative Services Agreement (ASA) and an existing Power Services Agency Agreement (PSA). We discuss the ASA and PSA in more detail in *Note 16*.

The merger agreement has been approved by the boards of directors of both Constellation Energy and Exelon and stockholders and by several other state and federal regulatory bodies. The parties are working to complete the merger in the first quarter of 2012 absent any Federal Energy Regulatory Commission approval delays.

Haynesville Shale Gas Property

In the fourth quarter of 2011, we acquired natural gas working interests and net revenue interests in certain producing wells and certain proved developed wells and proved undeveloped locations in Louisiana for a total of approximately $58.2 million, all of which was allocated to property, plant and equipment. This acquisition expanded our physical gas presence and will reduce our collateral costs. We accounted for this acquisition as a business combination within our NewEnergy business segment. The proforma impact of this acquisition would not have been material to our results of operations for the years ended December 31, 2011, 2010, and 2009.

ONEOK Energy Marketing Company

In February 2012, we acquired all of the outstanding stock of ONEOK Energy Marketing Company (OEMC), a retail natural gas marketing company, for approximately $22.5 million, subject to a working capital adjustment. OEMC serves approximately 26,100 customers. This acquisition will expand our retail residential customer base in seven states. We will account for this acquisition as a business combination within our NewEnergy business segment.

MXenergy Holdings Inc.

In July 2011, we acquired all of the outstanding stock of MXenergy Holdings Inc. (MXenergy), a retail energy marketer of natural gas and electricity to residential and commercial customers, for approximately $218.7 million in cash. MXenergy serves approximately 540,000 customers in numerous markets across the United States and Canada.

We recorded the acquisition as follows:

At July 1, 2011

	(In millions)
Cash and cash equivalents	$ 0.9
Accounts receivable	53.8

Restricted cash (1)		63.8
Other current assets		38.4
Goodwill (2)		108.8
Acquired contracts and intangibles (2)(3)		84.5
Other assets		13.0
Total assets acquired		363.2
Bond payable (1)		(82.9)
Other current liabilities		(60.4)
Noncurrent liabilities		(1.2)
Total liabilities		(144.5)
Net assets acquired	$	218.7

(1)
The bond payable was fully repaid during August 2011 primarily with the restricted cash.

(2)
None is deductible for tax purposes.

(3)
The weighted average amortization for these assets is approximately 4 years.

We have included MXenergy's results of operations in our consolidated financial statements as part of our NewEnergy business segment since the date of acquisition.

The proforma impact of this acquisition would not have been material to our results of operations for the years ended December 31, 2011, 2010, and 2009.

Star Electricity, Inc.

In May 2011, we acquired all of the outstanding stock of Star Electricity, Inc. (StarTex), a retail electric provider, for approximately $160.4 million in cash. StarTex serves approximately 170,000 customers in the Texas residential market.

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We recorded the acquisition as follows:

At May 27, 2011

	(In millions)
Cash and cash equivalents	$ 17.9
Other current assets	42.7
Goodwill(1)	93.6
Acquired contracts and intangibles(1)(2)	78.3
Other assets	1.3
Total assets acquired	233.8
Total liabilities	(73.4)
Net assets acquired	$ 160.4

(1) *None is deductible for tax purposes.*

(2) *The weighted average amortization for these assets is approximately 3 years.*

The net assets acquired amounts are preliminary pending final purchase price adjustments.

We have included StarTex's results of operations in our consolidated financial statements as part of our NewEnergy business segment since the date of acquisition.

The proforma impact of this acquisition would not have been material to our results of operations for the quarters and six months ended June 30, 2011 and 2010 and to our financial condition as of June 30, 2011 and December 31, 2010.

Boston Generating

In January 2011, we acquired Boston Generating's 2,950 MW fleet of generating plants for cash of approximately $1.1 billion. The fleet acquired includes the following four natural gas power plants and one fuel oil plant located in the Boston, Massachusetts area:

Mystic 7 574 MW,

Mystic 8 and 9 1,580 MW,

Fore River 787 MW, and

Mystic Jet, a fuel oil plant 9 MW.

We recorded the acquisition as follows:

At January 3, 2011

	(In millions)
Current assets	$ 92.2
Land	29.2
Property, plant and equipment	1,061.8
Noncurrent assets	0.1

Total assets acquired		1,183.3
Current liabilities		(77.5)
Noncurrent liabilities		(21.8)
Total liabilities		(99.3)
Net assets acquired	$	1,084.0

We have included the results of operations from these plants in our consolidated financial statements as part of our Generation business segment since the date of acquisition.

The proforma impact of this acquisition would not have been material to our results of operations for the quarters ended March 31, 2011 and 2010 and to our financial condition as of March 31, 2011 and December 31, 2010.

CPower

In October 2010, we acquired 100% ownership of CPower, an energy management and demand response provider, for $77.1 million in cash, all of which was paid at closing. CPower designs and manages programs that allow its customers to reduce electricity demand at times of peak usage. We have included CPower's results of operations in our consolidated financial statements as part of our NewEnergy business segment since the date of acquisition.

We recorded the acquisition as follows:

At October 11, 2010

	(In millions)	
Cash and cash equivalents	$	2.9
Other current assets		12.9
Goodwill (1)		54.3
Acquired intangible assets (2)		12.6
Other assets		10.6
Total assets acquired		93.3
Total liabilities		(16.2)
Net assets acquired	$	77.1

(1) *$3.6 million is deductible for tax purposes.*

(2) *The weighted average amortization for these intangibles is approximately 2 years.*

The pro-forma impact of this acquisition would not have been material to our results of operations for the years ended December 31, 2010 and 2009.

Texas Combined Cycle Generation Facilities

In May 2010, we acquired 100% ownership of the 550 MW Colorado Bend Energy Center and the 550 MW Quail Run Energy Center natural gas combined cycle generation facilities in Texas for $372.9 million, all of which was paid in cash at closing. We include these facilities as part of our Generation business and have included their results of operations in our consolidated financial statements since the date of acquisition.

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We recorded the acquisition as follows:

At May 17, 2010

	(In millions)
Current assets	$ 7.1
Property, plant and equipment	368.6
Total assets acquired	375.7
Current liabilities	(2.8)
Net assets acquired	$ 372.9

The pro-forma impact of this acquisition would not have been material to our results of operations for the years ended December 31, 2010 and 2009.

Criterion Wind Project

In April 2010, we acquired 100% ownership of a 70 MW Criterion wind project to be constructed in Garrett County, Maryland. In December 2010, we placed this facility in commercial operation. This wind energy project was developed, constructed, and is owned by our Generation business.

The pro-forma impact of all of the 2010 acquisitions, collectively, would not have been material to our results of operations for the years ended December 31, 2010 and 2009.

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16 Related Party Transactions

Constellation Energy

CENG

We have a unit contingent power purchase agreement (PPA) with CENG under which we purchase between 85-90% of the output of CENG's nuclear plants that is not sold to third parties under pre-existing PPAs through 2014. Beginning on January 1, 2015 and continuing to the end of the life of the respective plants, we will purchase 50.01% of the output of CENG's nuclear plants, and EDF will purchase 49.99% of that output.

In addition to the PPA, we have a power services agency agreement (PSA) and an administrative service agreement (ASA) with CENG. The PSA is a five-year agreement under which we will provide scheduling, asset management and billing services to CENG and recognize average annual revenue of approximately $16 million. The ASA expires in 2017 and under the agreement we provide certain administrative services to CENG including back office, human resources and information technology. The ASA includes both a consumption-based pricing structure as well as a fixed-price structure which are subject to change in future years based on the level of service needed. The fixed price fee for 2011 is approximately $48 million and will increase annually in line with inflation. The charges under this agreement are intended to represent the actual cost of the services provided to CENG by us.

The impact of transactions under these agreements is summarized below:

	Increase (Decrease) in Earnings				
Agreement	**Year Ended December 31, 2011**	**Year Ended December 31, 2010**	**Period from November 6, 2009 through December 31, 2009**	**Income Statement Classification**	**Accounts Receivable/ (Accounts Payable) December 31, 2011**
PPA	$ (888.4)	$ (900.8)	$ (122.5)	Fuel and purchased energy expenses	$ (47.5)
PSA	16.1	16.1	2.7	Nonregulated revenues	
ASA	48.0	66.0	10.0	Operating expenses	4.0

Upon the closing of the merger with Exelon, the ASA will be amended to reflect actual post-merger costs determined on the same basis that Exelon charges its affiliates for similar services. In addition, the PSA will be amended to reflect the cost of the service, with such cost not to exceed approximately $358,000 per month.

In May 2011, CENG issued an unsecured revolving promissory note to borrow up to an aggregate principal amount of $62.5 million from a subsidiary of Constellation Energy. CENG also issued an unsecured revolving promissory note to EDF on substantially identical terms, such that any request for borrowings by CENG must be submitted 50% to Constellation Energy and 50% to EDF.

Interest accrues on the amounts borrowed on a daily basis at a fixed rate per year equal to the rate at which deposits of United States dollars are offered by prime banks in the London interbank market, plus 250 basis points. Amounts are due at the earlier of October 31, 2012 or the date upon which the note is accelerated in accordance with the terms of the agreement.

As of December 31, 2011, CENG has borrowed $30.0 million from Constellation Energy.

During 2011, CENG executed settlement agreements with the DOE that detail a framework and procedure for recovery of damages incurred or to be incurred through the end of 2013. Constellation Energy, through its share of the settlement proceeds, recognized a total of $93.8 million in 2011 for costs incurred to store spent nuclear fuel. We discuss this settlement in more detail in *Note 2*.

UNE

We sold our interest in UNE during 2010. We discuss this transaction in more detail in *Note 4*.

CEP

In August 2011, we sold a majority of our interests in Constellation Energy Partners LLC (CEP) to PostRock Energy Corporation (PostRock). As a result of this transaction, we recorded a pre-tax gain of $23.0 million.

Additionally, in December 2011, we sold our remaining Class B member interests to PostRock. We recorded a pre-tax gain of $10.7 million on this transaction.

We discuss these transactions in more detail in *Note 2*.

BGE Income Statement

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

Our NewEnergy business will supply a portion of BGE's market-based standard offer service obligation to electric customers through May 31, 2014.

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,	**2011**	**2010**	**2009**
		(In millions)	
Electricity purchased for resale expenses	**$ 348.2**	$ 428.0	$ 623.5

In addition, Constellation Energy charges BGE for the costs of certain corporate functions. Certain costs, both capital and expense, 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.

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

Year ended December 31,	2011	2010	2009
		(In millions)	
Charges to BGE	**$ 178.6**	$ 184.8	$ 164.7

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

BGE Balance Sheet

Through January 7, 2010, BGE participated in a cash pool under a Master Demand Note agreement with Constellation Energy. Under this arrangement, participating subsidiaries may invest in or borrow from the pool at market interest rates. Constellation Energy administers the pool and invests excess cash in short-term investments or issues commercial paper to manage consolidated cash requirements.

As part of the ring-fencing measures required by the Maryland PSC in its order approving the transaction with EDF, BGE ceased participation in the cash pool on January 7, 2010.

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

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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.

2011 Quarterly Data Constellation Energy

	Revenues *	Fuel and Purchased Energy Expenses (includes amounts from affiliates) *	(Loss) Income from Operations	Net Income (Loss)	Net Income (Loss) Attributable to Common Stock	Earnings (Loss) Per Share from Operations Diluted	Earnings (Loss) Per Share of Common Stock Diluted
	(In millions, except per share amounts)						
Quarter Ended							
March 31	$ 3,570.2	$ 2,673.0	$ 217.6	$ 79.4	$ 70.4	$ 0.35	$ 0.35
June 30	3,359.8	2,380.9	260.1	108.1	99.2	0.49	0.49
September 30	3,875.4	2,984.6	229.8	97.9	73.7	0.36	0.36
December 31	2,952.8	2,246.5	(904.5)	(592.2)	(583.6)	(2.91)	(2.91)
Year Ended							
December 31	$ 13,758.2	$ 10,285.0	$ (197.0)	$ (306.8)	$ (340.3)	$ (1.70)	$ (1.70)

2011 Quarterly Data BGE

	Revenues	Income from Operations	Net Income	Net Income (Loss) Attributable to Common Stock
	(In millions)			
Quarter Ended				
March 31	$ 957.5	$ 153.4	$ 81.1	$ 77.8
June 30	656.2	52.7	16.6	13.3
September 30	722.9	22.8	1.6	(1.7)
December 31	656.5	85.9	36.4	33.1
Year Ended				
December 31	$ 2,993.1	$ 314.8	$ 135.7	$ 122.5

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.

* *In the fourth quarter of 2011, we identified adjustments that were required to revise certain unaffiliated amounts between "Revenues" and "Fuel and Purchased Energy Expenses" for the third quarter of 2011 in order to properly reflect activity in our Consolidated Statements of Income (Loss). This revision did not impact reported gross margin, income (loss) from operations, net income (loss), net income (loss) attributable to common stock, or cash flows from operations for the third quarter of 2011.*

First quarter results include:

- a $17.6 million after-tax charge for amortization of the basis difference in CENG,
- a $27.0 million after-tax charge for the impact of the PPA with CENG,
- a $10.0 million after-tax charge for transaction fees incurred related to our acquisition of Boston Generating's 2,950 MW fleet of generating plants in Massachusetts, and
- a $1.5 million after-tax amortization of credit facility amendment fees in connection with the EDF transaction.

Second quarter results include:

- a $24.0 million after-tax charge for amortization of the basis difference in CENG,
- a $30.3 million after-tax charge for the impact of the PPA with CENG,
- a $19.3 million after-tax charge for costs incurred related to our pending merger with Exelon,

a $21.3 million after-tax gain on the settlement with the DOE for storage of spent nuclear fuel at the Calvert Cliffs nuclear power plant through October 2008,

a $0.1 million after-tax charge for transaction fees incurred related to our acquisition of Boston Generating's 2,950 MW fleet of generating plants in Massachusetts,

a $1.5 million after-tax amortization of credit facility amendment fees in connection with the EDF transaction.

Third quarter results include:

a $26.3 million after-tax charge for amortization of the basis difference in CENG,

a $31.3 million after-tax charge for the impact of the PPA with CENG,

a $24.6 million after-tax charge for incremental operating expenses incurred related to Hurricane Irene,

a $14.3 million after-tax gain on the sale of interests in CEP,

a $5.1 million after-tax charge for costs incurred related to our pending merger with Exelon, and

a $1.5 million after-tax amortization of credit facility amendment fees in connection with the EDF transaction.

Fourth quarter results include:

a $530.2 million after-tax charge for the impairment of certain of our equity method investments,

a $22.6 million after-tax charge for amortization of the basis difference in CENG,

a $29.9 million after-tax charge for the impact of the PPA with CENG,

a $18.4 million after-tax gain on the sale of additional interests in CEP and certain working interests in upstream natural gas properties,

a $46.5 million after-tax charge for costs incurred related to our pending merger with Exelon,

a $36.0 million after-tax gain on the settlement with the DOE for storage of spent nuclear fuel at the Calvert Cliffs nuclear power plant and the Ginna nuclear power plant through November 6, 2009,

a $0.2 million after-tax benefit for an income tax true-up for costs incurred related to our acquisition of Boston Generating's 2,950 MW fleet of generating plants in Massachusetts, and

a $1.3 million after-tax amortization of credit facility amendment fees in connection with the EDF transaction.

We discuss these items in *Note 2*.

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2010 Quarterly Data Constellation Energy

	Revenues	Income (Loss) from Operations	Net Income (Loss)	Net Income (Loss) Attributable to Common Stock	Earnings (Loss) Per Share from Operations Diluted	Earnings (Loss) Per Share of Common Stock Diluted
	(In millions, except per share amounts)					
Quarter Ended						
March 31	**$ 3,586.6**	**$ 415.1**	**$ 191.3**	**$ 191.5**	**$ 0.95**	**$ 0.95**
June 30	**3,309.9**	**181.9**	**83.8**	**72.6**	**0.36**	**0.36**
September 30	**3,968.9**	**(2,246.7)**	**(1,375.0)**	**(1,406.5)**	**(6.99)**	**(6.99)**
December 31	**3,474.6**	**406.7**	**168.1**	**159.8**	**0.79**	**0.79**
Year Ended						
December 31	**$ 14,340.0**	**$ (1,243.0)**	**$ (931.8)**	**$ (982.6)**	**$ (4.90)**	**$ (4.90)**

2010 Quarterly Data BGE

	Revenues	Income from Operations	Net Income	Net Income Attributable to Common Stock
	(In millions)			
Quarter Ended				
March 31	**$ 1,069.3**	**$ 136.9**	**$ 64.4**	**$ 61.1**
June 30	**751.5**	**55.9**	**17.0**	**13.7**
September 30	**856.1**	**75.6**	**31.8**	**28.5**
December 31	**784.8**	**85.8**	**34.4**	**31.1**
Year Ended				
December 31	**$ 3,461.7**	**$ 354.2**	**$ 147.6**	**$ 134.4**

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.

First quarter results include:

- a $8.8 million after-tax charge for the deferred income tax expense impact relating to federal subsidies for providing post-employment prescription drug benefits,
- a $30.9 million after-tax loss for the early retirement of 2012 Notes,
- a $25.7 million after-tax charge for amortization of the basis difference in CENG,
- a $25.7 million after-tax charge for the impact of the PPA with CENG, and
- a $2.9 million after-tax amortization of credit facility amendment fees in connection with the EDF transaction.

Second quarter results include:

- a $37.0 million after-tax charge for amortization of the basis difference in CENG,
- a $29.1 million after-tax charge for the impact of the PPA with CENG, and
- a $2.9 million after-tax amortization of credit facility amendment fees in connection with the EDF transaction.

Third quarter results include:

- a $1,465.3 million after-tax charge for the impairment of certain of our equity method investments,
- a $31.5 million after-tax charge for amortization of the basis difference in CENG,
- a $28.9 million after-tax charge for the impact of the PPA with CENG,
- a $24.7 million after-tax gain on the sale of our interest in the Mammoth Lakes geothermal generating facility, and
- a $2.9 million after-tax amortization of credit facility amendment fees in connection with the EDF transaction.

Fourth quarter results include:

- a $21.8 million after-tax charge for an impairment and an adjustment to income tax expenses associated with certain of our equity method investments,
- a $23.3 million after-tax charge for amortization of the basis difference in CENG,
- a $29.6 million after-tax charge for the impact of the PPA with CENG,
- a $35.4 million after-tax gain on the settlement of an international coal contract dispute,
- a $121.3 million after-tax gain on the comprehensive agreement with EDF, and
- a $4.9 million after-tax amortization of credit facility amendment fees in connection with the EDF transaction.

We discuss these items in *Note 2*.

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Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

The principal executive officer and principal financial officer of Constellation Energy have each evaluated the effectiveness of the disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")) as of December 31, 2011 (the "Evaluation Date"). Based on such evaluation, such officers have concluded that, as of the Evaluation Date, Constellation Energy's disclosure controls and procedures are effective in providing reasonable assurance that information required to be disclosed in the reports that Constellation Energy files and submits under the Exchange Act is recorded, processed, summarized, and reported when required and is accumulated and communicated to management, as appropriate, to allow timely decisions regarding required disclosure.

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

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.

Changes in Internal Control

During the quarter ended December 31, 2011, 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, Executive Officers and Corporate Governance

The information required by this item with respect to directors and corporate governance will be set forth under *Proposal No. 1: 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, 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, 2011:

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	10,122	$ 41.14	10,144
Equity compensation plans not approved by security holders	534	$ 44.44	
Total	10,656	$ 41.31	10,144

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(j)) and the Constellation Energy Group, Inc. Management Long-Term Incentive Plan (Designated as Exhibit No. 10(k)). 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 Amended and Restated 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 become fully exercisable 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 Amended and Restated 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 2012* 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 29, 2012 of PricewaterhouseCoopers LLP
   Consolidated Statements of Income (Loss) Constellation Energy Group for three years ended December 31, 2011
   Consolidated Balance Sheets Constellation Energy Group at December 31, 2011 and December 31, 2010
   Consolidated Statements of Cash Flows Constellation Energy Group for three years ended December 31, 2011
   Consolidated Statements of Common Shareholders' Equity and Comprehensive Income (Loss) Constellation Energy Group for three years ended December 31, 2011
   Consolidated Statements of Income Baltimore Gas and Electric Company for three years ended December 31, 2011
   Consolidated Balance Sheets Baltimore Gas and Electric Company at December 31, 2011 and December 31, 2010
   Consolidated Statements of Cash Flows Baltimore Gas and Electric Company for three years ended December 31, 2011
   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(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)	Asset Purchase Agreement, dated as of August 7, 2010, by and among EBG Holdings LLC, Boston Generating, LLC, Mystic I, LLC, Fore River Development, LLC, BG Boston Services, LLC, BG New England Power Services, Inc., Constellation Holdings, Inc. and Constellation Energy Group, Inc. (Designated as Exhibit No. 2.1 to the Current Report on Form 8-K dated August 11, 2010, File No. 1-12869.)
*2(d)	Master Agreement, dated as of October 26, 2010, by and between Electricite de France, S.A. and Constellation Energy Group, Inc. (Designated as Exhibit No. 2.1 to the Current Report on Form 8-K dated November 1, 2010, File No. 1-12869.)
*2(e)	Put Termination Agreement dated as of November 3, 2010, by and among EDF Inc. (formerly known as EDF Development, Inc.), E.D.F. International S.A., Constellation Nuclear, LLC, and Constellation Energy Nuclear Group, LLC. (Designated as Exhibit No. 2.1 to the Current Report on Form 8-K dated November 8, 2010, File No. 1-12869.)
#*2(f)	Agreement and Plan of Merger, dated April 28, 2011, by and among Exelon Corporation, Constellation Energy Group, Inc. and Bolt Acquisition Corporation. (Designated as Exhibit No. 2.1 to the Current Report on Form 8-K dated April 28, 2011, File Nos. 1-12869 and 1-1910.)
*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)	Correction to Articles Supplementary to the Charter of Constellation Energy Group, Inc. as of November 25, 2008. (Designated as Exhibit No. 3(c) to the Annual Report on Form 10-K for the year ended December 31, 2008, File Nos. 1-12869 and 1-1910.)

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Exhibit Number	
*3(c)	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(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. 99.1 to the Current Report on Form 8-K dated July 19, 1999, File Nos. 1-12869 and 1-1910.)
*3(i)	Amended and Restated Charter 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)	Articles of Amendment to the Charter of BGE as of February 2, 2010. (Designated as Exhibit No. 3.1 to the Current Report on Form 8-K dated February 4, 2010, File No. 1-1910.)
*3(l)	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(m)	Bylaws of BGE, as amended to February 4, 2010. (Designated as Exhibit No. 3.2 to the Current Report on Form 8-K dated February 4, 2010, 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 as of July 24, 2006 between Constellation Energy Group, Inc. and Deutsche Bank Trust Company Americas, as trustee. (Designated as Exhibit No. 4(a) to the Registration Statement on Form S-3 filed July 24, 2006, File No. 333-135991.)
*4(d)	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 4(a) to the Current Report on Form 8-K dated June 30, 2008, File No. 1-12869.)
*4(e)	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(f)	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.)

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Exhibit Number	
*4(g)	Form of Subordinated Indenture between BGE 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(h)	Form of Supplemental Indenture between BGE and The Bank of New York, as Trustee in connection with the issuance 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(i)	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(j)	Form of Junior Subordinated Debenture (Designated as Exhibit 4(e) to the Registration Statement on Form S-3 dated August 5, 2003, File No. 333-107681.)
*4(k)	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(l)	Indenture dated as of July 24, 2006 between BGE 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 BGE and Deutsche Bank Trust Company Americas, as trustee, dated as of October 13, 2006. (Designated as Exhibit No. 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 and Security Agreement dated as of July 9, 2009, between BGE and Deutsche Bank Trust Company Americas, as trustee (including form of BGE Officer's Certificate and form of Senior Secured Bond) (Designated as Exhibit Nos. 4(u) and 4(u)(1) to Post-Effective Amendment No. 1 to the Registration Statement on Form S-3 dated July 9, 2009, File Nos. 333-157637 and 333-157637-01.)
*4(o)	Supplemental Indenture No. 1, dated as of October 1, 2009, to the Indenture and Security Agreement dated as of July 9, 2009, between BGE and Deutsche Bank Trust Company Americas, as trustee. (Designated as Exhibit No. 4(c) to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2009, File Nos. 1-12869 and 1-1910.)
*4(p)	BGE Deed of Easement and Right-of-Way Grant dated as of July 9, 2009 (Designated as Exhibit No. 4(u)(2) to Post-Effective Amendment No. 1 to the Registration Statement on Form S-3 dated July 9, 2009, File Nos. 333-157637 and 333-157637-01.)
*4(q)	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(r)	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 No. 4(b) to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2009, File No. 1-1910.)
*4(s)	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.)
*4(t)	Officers' Certificate, dated December 14, 2010, establishing the 5.15% Notes due December 1, 2020 of Constellation Energy Group, Inc., with the form of Notes attached thereto. (Designated as Exhibit No. 4(b) to the Current Report on Form 8-K dated December 14, 2010, File No. 1-12869.)
*4(u)	Officers' Certificate, November 16, 2011, establishing the 3.50% Notes due November 15, 2021 of Baltimore Gas and Electric Company, with the form of Notes attached thereto. (Designated as Exhibit No. 4(b) to the Current Report on Form 8-K dated November 16, 2011, File No. 1-1910.)
+*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.)

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Exhibit Number	
+*10(b)	Constellation Energy Group, Inc. Nonqualified Deferred Compensation Plan, as amended and restated. (Designated as Exhibit No. 10(b) to the Annual Report on Form 10-K for the year ended December 31, 2008, File Nos. 1-12869 and 1-1910.)
*10(c)	Constellation Energy Group, Inc. Deferred Compensation Plan for Non-Employee Directors, as amended and restated. (Designated as Exhibit No. 10(c) to the Annual Report on Form 10-K for the year ended December 31, 2008, File Nos. 1-12869 and 1-1910.)
+*10(d)	Constellation Energy Group, Inc. Benefits Restoration Plan, amended and restated effective June 1, 2010. (Designated as Exhibit No. 10(b) to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2010, File Nos. 1-12869 and 1-1910.)
+*10(e)	Constellation Energy Group, Inc. Supplemental Pension Plan, as amended and restated. (Designated as Exhibit No. 10(e) to the Annual Report on Form 10-K for the year ended December 31, 2008, File Nos. 1-12869 and 1-1910.)
+*10(f)	Constellation Energy Group, Inc. Senior Executive Supplemental Plan, as amended and restated. (Designated as Exhibit No. 10(f) to the Annual Report on Form 10-K for the year ended December 31, 2008, File Nos. 1-12869 and 1-1910.)
+*10(g)	Constellation Energy Group, Inc. Executive 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)	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(i)	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 June 30, 2011, File Nos. 1-12869 and 1-1910.)
+*10(j)	Constellation Energy Group, Inc. 2002 Senior Management 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 June 30, 2011, File Nos. 1-12869 and 1-1910.)
+*10(k)	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(l)	Constellation Energy Group, Inc. Amended and Restated 2007 Long-Term Incentive Plan. (Designated as Exhibit No. 10.1 to the Current Report on Form 8-K dated June 4, 2010, File No. 1-12869.)
+*10(m)	Consent of Mayo A. Shattuck III to termination of change-in-control agreement. (Designated as Exhibit No. 10.1 to the Current Report on Form 8-K dated December 10, 2009, File No. 1-12869.)
+*10(n)	Consent of Michael J. Wallace to termination of change-in-control agreement. (Designated as Exhibit No. 10.2 to the Current Report on Form 8-K dated December 10, 2009, File No. 1-12869.)
+*10(o)	Consent of Henry B. Barron, Jr. to termination of change-in-control agreement. (Designated as Exhibit No. 10.3 to the Current Report on Form 8-K dated December 10, 2009, File No. 1-12869.)
*10(p)	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(q)	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(r)	Second Amended and Restated Operating Agreement, dated as of November 6, 2009, by and among Constellation Energy Nuclear Group, LLC, Constellation Nuclear, LLC, CE Nuclear, LLC, EDF Development Inc., and for certain limited purposes, E.D.F. International S.A. and Constellation Energy Group, Inc. (Designated as Exhibit No. 10.1 to the Current Report on Form 8-K dated November 12, 2009, File No. 1-12869.)

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Exhibit Number	
*10(s)	Amendment No. 1 to the Second Amended and Restated Operating Agreement of Constellation Energy Nuclear Group, LLC, by and among Constellation Nuclear, LLC, CE Nuclear, LLC, EDF Inc. (formerly known as EDF Development, Inc.), and E.D.F. International S.A. (Designated as Exhibit No. 10(s) to the Annual Report on Form 10-K for the year ended December 31, 2010, File Nos. 1-12869 and 1-1910.)
*10(t)	Amendment No. 2 to the Second Amended and Restated Operating Agreement of Constellation Energy Nuclear Group, LLC, by and among Constellation Nuclear, LLC, CE Nuclear, LLC, EDF Inc. (formerly known as EDF Development, Inc.), and E.D.F. International S.A. (Designated as Exhibit No. 10(t) to the Annual Report on Form 10-K for the year ended December 31, 2010, File Nos. 1-12869 and 1-1910.)
*10(u)	Amendment No. 3 to the Second Amended and Restated Operating Agreement of Constellation Energy Nuclear Group, LLC, by and among Constellation Nuclear, LLC, CE Nuclear, LLC, EDF Inc. (formerly known as EDF Development, Inc.), and E.D.F. International S.A. (Designated as Exhibit No. 10.1 to the Current Report on Form 8-K dated November 3, 2010, File No. 1-12869.)
*10(v)	Credit Agreement, dated as of October 15, 2010, among Constellation Energy Group, Inc., Bank of America, N.A., as a letter of credit issuing bank, swingline lender and administrative agent, Banc of America Securities LLC, Citigroup Global Markets Inc., RBS Securities Inc., BNP Paribas Securities Corp., and The Bank of Nova Scotia, as joint lead arranger and book runners, Citibank, N.A. and The Royal Bank of Scotland plc, as co-syndication agents and The Bank of Nova Scotia and BNP Paribas, as co-documentation agents and the other lenders named therein. (Designated as Exhibit 10(a) to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2011, File No. 1-12869.)
*10(w)	Termination Agreement dated as of November 3, 2010, by and among EDF Inc. (formerly known as EDF Development, Inc.), E.D.F. International S.A., and Constellation Energy Group, Inc. (Designated as Exhibit No. 10.2 to the Current Report on Form 8-K dated November 3, 2010, File No. 1-12869.)
+*10(x)	Form of Grant Agreement for Stock Units with Sales Restriction. (Designated as Exhibit No. 10(x) to the Annual Report on Form 10-K for the year ended December 31, 2010, File Nos. 1-12869 and 1-1910.)
*10(y)	Settlement Agreement between EDF Inc., Exelon Corporation, Exelon Energy Delivery Company, LLC, Constellation Energy Group, Inc. and Baltimore Gas and Electric Company dated January 16, 2012. (Designated as Exhibit No. 10.1 to the Current Report on Form 8-K dated January 19, 2012, File Nos. 1-12869 and 1-1910.)
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(a)	Consent of PricewaterhouseCoopers LLP, Independent Registered Public Accounting Firm.
23(b)	Consent of PricewaterhouseCoopers LLP, Independent Registered Public Accounting Firm (for Constellation Energy Nuclear Group, LLC).
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 Chief Financial Officer and Treasurer of Baltimore Gas and Electric Company pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

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Exhibit Number	
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 Chief Financial Officer and Treasurer 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.
99(a)	Audited Financial Statements of Constellation Energy Nuclear Group, LLC.
*99(b)	Operating Agreement, dated as of February 4, 2010, by and among RF HoldCo LLC, Constellation Energy Group, Inc. and GSS Holdings (BGE Utility), Inc. (Designated as Exhibit No. 99.1 to the Current Report on Form 8-K dated February 4, 2010, File Nos. 1-12869 and 1-1910.)
*99(c)	Contribution Agreement, dated as of February 4, 2010, by and among Constellation Energy Group, Inc., BGE and RF HoldCo LLC. (Designated as Exhibit No. 99.2 to the Current Report on Form 8-K dated February 4, 2010, File Nos. 1-12869 and 1-1910.)
*99(d)	Purchase Agreement, dated as of February 4, 2010, by and between RF HoldCo LLC and GSS Holdings (BGE Utility), Inc. (Designated as Exhibit No. 99.3 to the Current Report on Form 8-K dated February 4, 2010, File Nos. 1-12869 and 1-1910.)
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema Document
101.PRE	XBRL Taxonomy Presentation Linkbase Document
101.LAB	XBRL Taxonomy Label Linkbase Document
101.CAL	XBRL Taxonomy Calculation Linkbase Document
101.DEF	XBRL Taxonomy Definition Linkbase Document

+ *Management contract or compensatory plan or arrangement.*

* *Incorporated by Reference.*

\# *Schedules have been omitted pursuant to Item 601(b)(2) of Regulation S-K. Constellation Energy will furnish the omitted schedules to the Securities and Exchange Commission upon request by the Commission.*

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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					
2011	$ 172.9	$ 84.5	$ (6.3)(F)	$ (48.5)(C)	$ 202.6
2010	160.6	76.2	27.6 (B)	(91.5)(C)	172.9
2009	240.6	71.2	(5.0)(A)	(146.2)(C)	160.6
Valuation Allowance					
Net unrealized (gain) loss on available for sale securities					
2011	(2.9)		0.1 (D)		(2.8)
2010	(2.8)		(0.1)(D)		(2.9)
2009	2.1	(3.6)	(1.3)(D)		(2.8)
Net unrealized (gain) loss on nuclear decommissioning trust funds					
2011					
2010					
2009	(49.6)		(201.0)(D)	250.6 (E)	
BGE					
Accumulated Provision for Uncollectibles					
2011	35.9	39.4		(37.6)(C)	37.7
2010	47.2	45.6		(56.9)(C)	35.9
2009	34.2	41.8		(28.8)(C)	47.2

(A)
Represents amounts recorded as an increase to nonregulated revenues resulting from a settlement with a counterparty that was in default.

(B)
Represents amounts recorded as a reduction to nonregulated revenues resulting from liquidated damages claims upon termination of derivatives or other contracts which were determined to be uncollectible.

(C)
Represents principally net amounts charged off as uncollectible.

(D)
Represents amounts recorded in or reclassified from accumulated other comprehensive loss.

(E)
Represents decrease due to the deconsolidation of CENG.

(F)
Represents amounts recorded against revenue as part of the acquisition of MXenergy and StarTex.

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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 29, 2012 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 29, 2012
Principal financial officer:		
By /s/ J. W. Thayer **J. W. Thayer**	Senior Vice President and Chief Financial Officer	February 29, 2012
Principal accounting officer:		
By /s/ B. P. Wright **B. P. Wright**	Vice President, Chief Accounting Officer, and Controller	February 29, 2012
Directors:		
/s/ Y. C. de Balmann **Y. C. de Balmann**	Director	February 29, 2012
/s/ A. C Berzin	Director	February 29, 2012

	A. C. Berzin		
/s/	J. T. Brady	Director	February 29, 2012
	J. T. Brady		
/s/	J. R. Curtiss	Director	February 29, 2012
	J. R. Curtiss		
/s/	F. A. Hrabowski, III	Director	February 29, 2012
	F. A. Hrabowski, III		

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Signature		Title	Date
/s/	N. Lampton	Director	February 29, 2012
	N. Lampton		
/s/	R. J. Lawless	Director	February 29, 2012
	R. J. Lawless		
/s/	J. L. Skolds	Director	February 29, 2012
	J. L. Skolds		
/s/	M. D. Sullivan	Director	February 29, 2012
	M. D. Sullivan		

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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 29, 2012 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 29, 2012
K. W. DeFontes, Jr.		
Principal financial and accounting officer:		
By /s/ C.V. Khouzami	Chief Financial Officer and Treasurer	February 29, 2012
C. V. Khouzami		
Directors:		
/s/ M. D. Sullivan	Chairman of the Board of Directors	February 29, 2012
M. D. Sullivan		
/s/ T. F. Brady	Director	February 29, 2012
T. F. Brady		
/s/ J. Haskins, Jr.	Director	February 29, 2012
J. Haskins, Jr.		
/s/ C. D. Hayden	Director	February 29, 2012
C. D. Hayden		
/s/ M. A. Shattuck III	Director	February 29, 2012

M. A. Shattuck III

/s/	M. J. Wallace	Director	February 29, 2012

M. J. Wallace

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EXHIBIT INDEX

Exhibit Number	
*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)	Asset Purchase Agreement, dated as of August 7, 2010, by and among EBG Holdings LLC, Boston Generating, LLC, Mystic I, LLC, Fore River Development, LLC, BG Boston Services, LLC, BG New England Power Services, Inc., Constellation Holdings, Inc. and Constellation Energy Group, Inc. (Designated as Exhibit No. 2.1 to the Current Report on Form 8-K dated August 11, 2010, File No. 1-12869.)
*2(d)	Master Agreement, dated as of October 26, 2010, by and between Electricite de France, S.A. and Constellation Energy Group, Inc. (Designated as Exhibit No. 2.1 to the Current Report on Form 8-K dated November 1, 2010, File No. 1-12869.)
*2(e)	Put Termination Agreement dated as of November 3, 2010, by and among EDF Inc. (formerly known as EDF Development, Inc.), E.D.F. International S.A., Constellation Nuclear, LLC, and Constellation Energy Nuclear Group, LLC. (Designated as Exhibit No. 2.1 to the Current Report on Form 8-K dated November 8, 2010, File No. 1-12869.)
#*2(f)	Agreement and Plan of Merger, dated April 28, 2011, by and among Exelon Corporation, Constellation Energy Group, Inc. and Bolt Acquisition Corporation. (Designated as Exhibit No. 2.1 to the Current Report on Form 8-K dated April 28, 2011, File Nos. 1-12869 and 1-1910.)
*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)	Correction to Articles Supplementary to the Charter of Constellation Energy Group, Inc. as of November 25, 2008. (Designated as Exhibit No. 3(c) to the Annual Report on Form 10-K for the year ended December 31, 2008, File Nos. 1-12869 and 1-1910.)
*3(c)	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(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. 99.1 to the Current Report on Form 8-K dated July 19, 1999, File Nos. 1-12869 and 1-1910.)

*3(i)	Amended and Restated Charter 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.)

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Exhibit Number	
*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)	Articles of Amendment to the Charter of BGE as of February 2, 2010. (Designated as Exhibit No. 3.1 to the Current Report on Form 8-K dated February 4, 2010, File No. 1-1910.)
*3(l)	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(m)	Bylaws of BGE, as amended to February 4, 2010. (Designated as Exhibit No. 3.2 to the Current Report on Form 8-K dated February 4, 2010, 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 as of July 24, 2006 between Constellation Energy Group, Inc. and Deutsche Bank Trust Company Americas, as trustee. (Designated as Exhibit No. 4(a) to the Registration Statement on Form S-3 filed July 24, 2006, File No. 333-135991.)
*4(d)	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 4(a) to the Current Report on Form 8-K dated June 30, 2008, File No. 1-12869.)
*4(e)	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(f)	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(g)	Form of Subordinated Indenture between BGE 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(h)	Form of Supplemental Indenture between BGE and The Bank of New York, as Trustee in connection with the issuance 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(i)	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(j)	Form of Junior Subordinated Debenture (Designated as Exhibit 4(e) to the Registration Statement on Form S-3 dated August 5, 2003, File No. 333-107681.)
*4(k)	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(l)	Indenture dated as of July 24, 2006 between BGE 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 BGE and Deutsche Bank Trust Company Americas, as trustee, dated as of October 13, 2006. (Designated as Exhibit No. 4(a) to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2006, File Nos. 1-12869 and 1-1910.)

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Exhibit Number	
*4(n)	Indenture and Security Agreement dated as of July 9, 2009, between BGE and Deutsche Bank Trust Company Americas, as trustee (including form of BGE Officer's Certificate and form of Senior Secured Bond) (Designated as Exhibit Nos. 4(u) and 4(u)(1) to Post-Effective Amendment No. 1 to the Registration Statement on Form S-3 dated July 9, 2009, File Nos. 333-157637 and 333-157637-01.)
*4(o)	Supplemental Indenture No. 1, dated as of October 1, 2009, to the Indenture and Security Agreement dated as of July 9, 2009, between BGE and Deutsche Bank Trust Company Americas, as trustee. (Designated as Exhibit No. 4(c) to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2009, File Nos. 1-12869 and 1-1910.)
*4(p)	BGE Deed of Easement and Right-of-Way Grant dated as of July 9, 2009 (Designated as Exhibit No. 4(u)(2) to Post-Effective Amendment No. 1 to the Registration Statement on Form S-3 dated July 9, 2009, File Nos. 333-157637 and 333-157637-01.)
*4(q)	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(r)	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 No. 4(b) to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2009, File No. 1-1910.)
*4(s)	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.)
*4(t)	Officers' Certificate, dated December 14, 2010, establishing the 5.15% Notes due December 1, 2020 of Constellation Energy Group, Inc., with the form of Notes attached thereto. (Designated as Exhibit No. 4(b) to the Current Report on Form 8-K dated December 14, 2010, File No. 1-12869.)
*4(u)	Officers' Certificate, November 16, 2011, establishing the 3.50% Notes due November 15, 2021 of Baltimore Gas and Electric Company, with the form of Notes attached thereto. (Designated as Exhibit No. 4(b) to the Current Report on Form 8-K dated November 16, 2011, File No. 1-1910.)
+*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. (Designated as Exhibit No. 10(b) to the Annual Report on Form 10-K for the year ended December 31, 2008, File Nos. 1-12869 and 1-1910.)
*10(c)	Constellation Energy Group, Inc. Deferred Compensation Plan for Non-Employee Directors, as amended and restated. (Designated as Exhibit No. 10(c) to the Annual Report on Form 10-K for the year ended December 31, 2008, File Nos. 1-12869 and 1-1910.)
+*10(d)	Constellation Energy Group, Inc. Benefits Restoration Plan, amended and restated effective June 1, 2010. (Designated as Exhibit 10(b) to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2010, File Nos. 1-12869 and 1-1910.)
+*10(e)	Constellation Energy Group, Inc. Supplemental Pension Plan, as amended and restated. (Designated as Exhibit No. 10(e) to the Annual Report on Form 10-K for the year ended December 31, 2008, File Nos. 1-12869 and 1-1910.)
+*10(f)	Constellation Energy Group, Inc. Senior Executive Supplemental Plan, as amended and restated. (Designated as Exhibit No. 10(f) to the Annual Report on Form 10-K for the year ended December 31, 2008, File Nos. 1-12869 and 1-1910.)
+*10(g)	Constellation Energy Group, Inc. Executive 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.)

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Exhibit Number	
+*10(h)	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(i)	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 June 30, 2011, File Nos. 1-12869 and 1-1910.)
+*10(j)	Constellation Energy Group, Inc. 2002 Senior Management 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 June 30, 2011, File Nos. 1-12869 and 1-1910.)
+*10(k)	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(l)	Constellation Energy Group, Inc. Amended and Restated 2007 Long-Term Incentive Plan. (Designated as Exhibit No. 10.1 to the Current Report on Form 8-K dated June 4, 2010, File No. 1-12869.)
+*10(m)	Consent of Mayo A. Shattuck III to termination of change-in-control agreement. (Designated as Exhibit No. 10.1 to the Current Report on Form 8-K dated December 10, 2009, File No. 1-12869.)
+*10(n)	Consent of Michael J. Wallace to termination of change-in-control agreement. (Designated as Exhibit No. 10.2 to the Current Report on Form 8-K dated December 10, 2009, File No. 1-12869.)
+*10(o)	Consent of Henry B. Barron, Jr. to termination of change-in-control agreement. (Designated as Exhibit No. 10.3 to the Current Report on Form 8-K dated December 10, 2009, File No. 1-12869.)
*10(p)	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(q)	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(r)	Second Amended and Restated Operating Agreement, dated as of November 6, 2009, by and among Constellation Energy Nuclear Group, LLC, Constellation Nuclear, LLC, CE Nuclear, LLC, EDF Development Inc., and for certain limited purposes, E.D.F. International S.A. and Constellation Energy Group, Inc. (Designated as Exhibit No. 10.1 to the Current Report on Form 8-K dated November 12, 2009, File No. 1-12869.)
*10(s)	Amendment No. 1 to the Second Amended and Restated Operating Agreement of Constellation Energy Nuclear Group, LLC, by and among Constellation Nuclear, LLC, CE Nuclear, LLC, EDF Inc. (formerly known as EDF Development, Inc.), and E.D.F. International S.A. (Designated as Exhibit No. 10(s) to the Annual Report on Form 10-K for the year ended December 31, 2010, File Nos. 1-12869 and 1-1910.)
*10(t)	Amendment No. 2 to the Second Amended and Restated Operating Agreement of Constellation Energy Nuclear Group, LLC, by and among Constellation Nuclear, LLC, CE Nuclear, LLC, EDF Inc. (formerly known as EDF Development, Inc.), and E.D.F. International S.A. (Designated as Exhibit No. 10(t) to the Annual Report on Form 10-K for the year ended December 31, 2010, File Nos. 1-12869 and 1-1910.)
*10(u)	Amendment No. 3 to the Second Amended and Restated Operating Agreement of Constellation Energy Nuclear Group, LLC, by and among Constellation Nuclear, LLC, CE Nuclear, LLC, EDF Inc. (formerly known as EDF Development, Inc.), and E.D.F. International S.A. (Designated as Exhibit No. 10.1 to the Current Report on Form 8-K dated November 3, 2010, File No. 1-12869.)

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Exhibit Number	
*10(v)	Credit Agreement, dated as of October 15, 2010, among Constellation Energy Group, Inc., Bank of America, N.A., as a letter of credit issuing bank, swingline lender and administrative agent, Banc of America Securities LLC, Citigroup Global Markets Inc., RBS Securities Inc., BNP Paribas Securities Corp., and The Bank of Nova Scotia, as joint lead arranger and book runners, Citibank, N.A. and The Royal Bank of Scotland plc, as co-syndication agents and The Bank of Nova Scotia and BNP Paribas, as co-documentation agents and the other lenders named therein. (Designated as Exhibit 10(a) to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2011, File No. 1-12869.)
*10(w)	Termination Agreement dated as of November 3, 2010, by and among EDF Inc. (formerly known as EDF Development, Inc.), E.D.F. International S.A., and Constellation Energy Group, Inc. (Designated as Exhibit No. 10.2 to the Current Report on Form 8-K dated November 3, 2010, File No. 1-12869.)
+*10(x)	Form of Grant Agreement for Stock Units with Sales Restriction. (Designated as Exhibit No. 10(x) to the Annual Report on Form 10-K for the year ended December 31, 2010, File Nos. 1-12869 and 1-1910.)
*10(y)	Settlement Agreement between EDF Inc., Exelon Corporation, Exelon Energy Delivery Company, LLC, Constellation Energy Group, Inc. and Baltimore Gas and Electric Company dated January 16, 2012. (Designated as Exhibit No. 10.1 to the Current Report on Form 8-K dated January 19, 2012, File Nos. 1-12869 and 1-1910.)
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(a)	Consent of PricewaterhouseCoopers LLP, Independent Registered Public Accounting Firm.
23(b)	Consent of PricewaterhouseCoopers LLP, Independent Registered Public Accounting Firm (for Constellation Energy Nuclear Group, LLC).
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.
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Exhibit Number	
*99(c)	Contribution Agreement, dated as of February 4, 2010, by and among Constellation Energy Group, Inc., BGE and RF HoldCo LLC. (Designated as Exhibit No. 99-2 to the Current Report on Form 8-K dated February 4, 2010, File Nos. 1-12869 and 1-1910.)
*99(d)	Purchase Agreement, dated as of February 4, 2010, by and between RF HoldCo LLC and GSS Holdings (BGE Utility), Inc. (Designated as Exhibit No. 99-3 to the Current Report on Form 8-K dated February 4, 2010, File Nos. 1-12869 and 1-1910.)
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema Document
101.PRE	XBRL Taxonomy Presentation Linkbase Document
101.LAB	XBRL Taxonomy Label Linkbase Document
101.CAL	XBRL Taxonomy Calculation Linkbase Document
101.DEF	XBRL Taxonomy Definition Linkbase Document

+ *Management contracts or compensatory plan or arrangement.*

* *Incorporated by Reference.*

Schedules have been omitted pursuant to Item 601(b)(2) of Regulation S-K. Constellation Energy will furnish the omitted schedules to the Securities and Exchange Commission upon request by the Commission.