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.

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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

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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,

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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;

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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.

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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**				