CONSTELLATION ENERGY GROUP INC
Form 10-K
March 03, 2006

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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, 2005**

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

MARYLAND

(States of incorporation)

750 E. PRATT STREET BALTIMORE, MARYLAND 21202
(Address of principal executive offices) (Zip Code)

410-783-2800
(Registrants' telephone number, including area code)

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

Title of each class	Name of each exchange on which registered
Constellation Energy Group, Inc. Common Stock Without Par Value	New York Stock Exchange, Inc. Chicago Stock Exchange, Inc. Pacific Exchange, Inc.
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, Inc.

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. ý

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

Large accelerated filer ý Accelerated filer o Non-accelerated filer o

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

Large accelerated filer o Accelerated filer o Non-accelerated filer ý

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, 2005 was approximately $10,225,051,449 based upon New York Stock Exchange composite transaction closing price.

CONSTELLATION ENERGY GROUP, INC. COMMON STOCK, WITHOUT PAR VALUE
178,454,929 SHARES OUTSTANDING ON JANUARY 31, 2006.

DOCUMENTS INCORPORATED BY REFERENCE

Part of Form 10-K	Document Incorporated by Reference
III	Certain sections of the Proxy Statement for the 2006 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,

- the liquidity and competitiveness of wholesale markets for energy commodities,

- the effect of weather and general economic and business conditions on energy supply, demand, and prices,

- the ability to attract and retain customers in our competitive supply activities and to adequately forecast their energy usage,

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

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

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

- the inability of Baltimore Gas and Electric Company (BGE) to recover all its costs associated with providing electric residential customers service during or after the electric rate freeze period,

- the conditions of the capital markets, interest rates, foreign exchange rates, availability of credit facilities to support business requirements, and general economic conditions, as well as Constellation Energy Group's (Constellation Energy) and BGE's 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,

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

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

- changes in accounting principles or practices,

- 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,

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

- the likelihood and timing of the completion of the pending merger with FPL Group, Inc. (FPL Group), 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, including *Item 1A. Risk Factors*, 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 assume responsibility to update these forward looking statements.

PART I

Item 1. Business

Pending Merger with FPL Group, Inc.

On December 18, 2005, Constellation Energy entered into an Agreement and Plan of Merger with FPL Group. The merger agreement has been unanimously approved by both companies' boards of directors but completion of the merger is contingent upon, among other things, the approval of the transaction by shareholders of both companies and receipt of required regulatory approvals. The companies anticipate obtaining all necessary approvals and completing the merger by the end of 2006. The merger agreement contains certain termination rights for both Constellation Energy and FPL Group, and further provides for the payment of fees upon termination of the merger agreement under specified circumstances. Further information concerning the pending merger will be included in the joint proxy statement/prospectus contained in the registration statement on Form S-4 to be filed by Constellation Energy in connection with the merger. For additional information related to the merger, see *Note 15 to the Consolidated Financial Statements*.

Overview

Constellation Energy is an energy company which includes a merchant energy business and BGE, a regulated electric and gas public utility in central Maryland.

Constellation Energy was incorporated in Maryland on September 25, 1995. On April 30, 1999, Constellation Energy became the holding company for BGE and its subsidiaries. References in this report to "we" and "our" are to Constellation Energy and its subsidiaries, collectively. References in this report to the "regulated business(es)" are to BGE.

Our merchant energy business is a competitive provider of energy solutions for a variety of customers. It has electric generation assets located in various regions of the United States and provides energy solutions to meet customers' needs. Our merchant energy business focuses on serving the full energy and capacity requirements (load-serving) of, and providing other energy products and risk management services for various customers.

Our merchant energy business includes:

- a generation operation that owns, operates, and maintains fossil, nuclear, and hydroelectric generating facilities and holds interests in qualifying facilities, fuel processing facilities and power projects in the United States,
- a wholesale marketing and risk management operation that primarily provides energy products and services to distribution utilities, power generators, and other wholesale customers,
- an electric and natural gas retail operation that provides energy products and services to commercial, industrial, and governmental customers, and
- a generation operations and maintenance services operation.

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

Our other nonregulated businesses:

- design, construct, and operate heating, cooling, and cogeneration facilities for commercial, industrial, and governmental customers throughout North America, and
- provide home improvements, service heating, air conditioning, plumbing, electrical, and indoor air quality systems, and provide natural gas to residential customers in central Maryland.

For a discussion of recent events that have impacted us, our strategy, and the seasonality of our business, please refer to *Item 7. Management's Discussion and Analysis* section.

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 and Insider Trading Policy, and the charters for the Audit, Compensation and Nominating, and Corporate Governance Committees of the Board of Directors. Copies of each of these documents may be printed from the 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 which 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.

Operating Segments

The percentages of revenues, net income, 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 the Consolidated Financial Statements*.

	Unaffiliated Revenues			
	Merchant Energy	**Regulated Electric**	**Regulated Gas**	**Other Nonregulated**
2005	81%	12%	6%	1%
2004	76	16	6	2
2003	68	20	8	4

	Net Income (1)			
	Merchant Energy	**Regulated Electric**	**Regulated Gas**	**Other Nonregulated**
2005	71%	25%	4%	%
2004	75	23	4	(2)
2003	66	24	9	1

	Total Assets			
	Merchant Energy	**Regulated Electric**	**Regulated Gas**	**Other Nonregulated**
2005	77%	16%	6%	1%
2004	71	20	7	2
2003	67	23	7	3

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

(1) Excludes income (loss) on discontinued operations in 2005, 2004, and 2003 and cumulative effects of changes in accounting principles in 2005 and 2003 as discussed in more detail in *Item 8. Financial Statements and Supplementary Data*.

Merchant Energy Business

Introduction

Our merchant energy business integrates electric generation assets with the marketing and risk management of energy and energy-related commodities, allowing us to manage energy price risk over geographic regions and time.

Constellation Energy Commodities Group, our wholesale marketing and risk management operation, dispatches the energy from our generating facilities and from some facilities with which we have power purchase agreements, manages the risks associated with selling the output and purchasing non-nuclear fuels, and enters into transactions to meet customers' energy and risk management requirements. This operation also trades energy and energy-related commodities and deploys risk capital in the management of our portfolio in order to earn additional returns. Constellation NewEnergy, our electric and gas retail operation, provides electricity, natural gas, transportation, and other energy services to commercial, industrial, and governmental customers.

Constellation Generation Group, our merchant generation operation, oversees the ownership, operations, maintenance, and performance of our fossil, nuclear and renewable generation and fuel processing facilities. Our generation capacity supports our wholesale and retail operations by providing a source of reliable power supply. Constellation Generation Group also owns and operates a generation operations and maintenance services organization.

Our merchant energy business:

provided service to distribution utilities, municipalities, commercial and industrial, and governmental customers with approximately 39,500 megawatts (MW) of peak load in the aggregate during 2005,

provided approximately 300,000 million British Thermal Units (mmBTUs) of natural gas to commercial, industrial, and governmental customers during 2005,

delivered 12.6 million tons of coal to international and domestic third-party customers and to our own fleet during 2005, and

managed approximately 11,850 MW of generation capacity.

We analyze the results of our merchant energy business as follows:

Mid-Atlantic Region our fossil, nuclear, and hydroelectric generating facilities and load-serving activities in the PJM Interconnection (PJM) region. This also includes active portfolio management of the generating assets and other physical and financial contractual arrangements, as well as other PJM competitive supply activities.

Plants with Power Purchase Agreements our generating facilities outside the Mid-Atlantic Region with long-term power purchase agreements, including our Nine Mile Point Nuclear Station (Nine Mile Point), R.E. Ginna Nuclear Plant (Ginna), University Park, and High Desert generating facilities.

Wholesale Competitive Supply our marketing and risk management operation that provides energy products and services (including portfolio management and trading activities) outside the Mid-Atlantic Region primarily to distribution utilities, power generators, and other wholesale customers. We also provide global coal and upstream and downstream natural gas services.

Retail Competitive Supply our operation that provides electric and natural gas energy products and services to commercial, industrial and governmental customers.

Other our investments in qualifying facilities and domestic power projects and our generation operations and maintenance services.

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

Mid-Atlantic Region

We own 6,960 MW of fossil, nuclear, and hydroelectric generation capacity in the Mid-Atlantic Region. The output of these plants is managed by our wholesale marketing and risk management operation and is hedged through a combination of power sales to wholesale and retail market participants. Our merchant energy business meets the load-serving requirements of various contracts using the output from the Mid-Atlantic Region and from purchases in the wholesale market.

BGE transferred all of these facilities to our merchant energy generation subsidiaries on July 1, 2000 as a result of the implementation of electric customer choice and competition among suppliers in Maryland, except for the Handsome Lake, Big Sandy, and Wolf Hills facilities that commenced operations in mid-2001. The assets transferred from BGE are subject to the lien of BGE's mortgage.

Our merchant energy business provides power to enable BGE to provide standard offer service as discussed in the *Baltimore Gas and Electric Company Standard Offer Service* section. For 2005, the peak load supplied to BGE was approximately 4,000 MW.

Plants with Power Purchase Agreements

We own 3,189 MW of nuclear and natural gas generation capacity with power purchase agreements for their output. Our facilities with power purchase agreements consist of:

- the Nine Mile Point facility,
- the Ginna facility,
- the High Desert facility, and
- the University Park facility.

We own 100% of Nine Mile Point Unit 1 (620 MW) and 82% of Unit 2 (941 MW). The remaining interest in Nine Mile Point Unit 2 is owned by the Long Island Power Authority. Unit 1 entered service in 1969 and Unit 2 in 1988. Nine Mile Point is located within the New York Independent System Operator (NYISO) region.

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

After termination of the power purchase agreements, a revenue sharing agreement with the former owners of the plant will begin and continue through 2021. Under this agreement, which applies only to our ownership percentage of Unit 2, a predetermined 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 revenue sharing agreement is unit contingent and is based on the operation of the unit.

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

In May 2004, we filed an application with the Nuclear Regulatory Commission (NRC) for a 20-year license extension for both units at Nine Mile Point. The license to operate Nine Mile Point's Unit 1 expires in 2009 and the license to operate Unit 2 expires in 2026. We must demonstrate that we can ensure that the units will continue to perform their intended functions through the renewal period. The NRC will also consider the impact of the 20-year license extension on the environment. We expect to receive approval of our application by early 2007 and have assumed a 20-year license extension for purposes of recording depreciation expense and asset retirement obligations. However, we cannot predict the actual timing of the NRC's decision, or the impact of the decision, if any, on our financial results. If we do not receive the license extension, we will not be able to operate the Nine Mile Point units beyond 2009 and 2026.

In June 2004, we purchased the Ginna nuclear facility which is located in Ontario, New York from Rochester Gas & Electric Corporation (RG&E). Ginna consists of a 498 MW reactor that entered service in 1970 and is licensed to operate until 2029. The acquisition includes a long-term unit contingent power purchase agreement under which we sell up to 90% of the plant's output and capacity to RG&E for 10 years at an average price of $44.00 per MWH. The remaining output is managed by our wholesale marketing and risk management operation and sold into the wholesale market. We expect to increase the capacity of Ginna by 83 MW through a planned uprate in 2006.

The High Desert facility has a long-term power sales agreement with the California Department of Water Resources (CDWR). The agreement has a "tolling" feature, under which the CDWR pays a fixed amount of $12.1 million per month which provides CDWR the right, but not the obligation, to purchase power at a price linked to the variable cost of production. During the term of the agreement, which runs until January 2011, the facility will provide energy exclusively to the CDWR.

We have sold 100% of the output of the University Park facility under a tolling agreement ending May 31, 2006. Under this tolling agreement, our counterparty will pay a fixed amount per month and have the right, but not the obligation, to purchase power from us at prices linked to the variable fuel and other costs of production.

In the second quarter of 2005, we sold our Oleander generating facility. We discuss this sale in more detail in *Note 2 to the Consolidated Financial Statements.*

Competitive Supply

We are a leading supplier of energy products and services to wholesale customers and retail commercial and industrial customers. In 2005, our wholesale marketing and risk management operation provided approximately 24,000 peak MWs of wholesale full requirements load-serving products. During 2005, our retail competitive supply activities served approximately 15,500 MW of peak load and approximately 300,000 mmBTUs of natural gas. Our competitive supply activities also include 1,465 MW of capacity from our Rio Nogales and Holland Energy natural gas-fired generating facilities. These facilities are not sold forward under long-term agreements, and their output is used to serve customer requirements.

Wholesale and Retail Load-Serving Activities

We structure transactions that serve the full energy and capacity requirements of various customers outside the PJM region such as distribution utilities, municipalities, cooperatives, and retail aggregators that do not own sufficient generating capacity or in-house supply functions to meet their own load requirements. We also structure transactions to supply full energy and capacity requirements and provide natural gas, transportation, and other energy products and services to retail commercial and industrial customers.

Contracts with these customers generally extend from one to ten years, but some can be longer. To meet our customers' load-serving requirements, our merchant energy business obtains energy from various sources, including:

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

Portfolio Management and Trading

Our wholesale marketing and risk management operation actively uses energy and energy-related commodities in order to manage our portfolio of energy purchases and sales to customers through structured transactions. As part of our risk management activities, we trade energy and energy-related commodities and deploy risk capital in the management of our portfolio in order to earn additional returns. These activities are managed through daily value at risk and stop loss limits and liquidity guidelines, and could have a material impact on our financial results. We discuss the impact of our trading activities and value at risk in more detail in *Item 7. Management's Discussion and Analysis.*

These activities involve the use of 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).

Active portfolio management allows our wholesale marketing and risk management operation 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.

Coal Services

Our wholesale marketing and risk management operation participates in global coal sourcing activities by providing coal and coal related logistical services, such as transportation for the variable or fixed supply needs of North American and international power generators. In 2005, we delivered 12.6 million tons of coal to international and domestic third- party customers and to our own fleet.

We also include in our coal services the results from our synthetic fuel processing facility in South Carolina.

Natural Gas Services

Our wholesale marketing and risk management operation provides products and services to upstream (exploration and production) and downstream (transportation and storage) natural gas customers, including large utilities, industrial customers, power generators, wholesale marketers, and retail aggregators.

In June 2005, we acquired working interests in gas producing fields in Texas and Alabama. We discuss this asset acquisition in more detail in *Note 15 to the Consolidated Financial Statements*.

Other

We hold up to a 50% voting interest in 24 operating energy projects that consist of electric generation (primarily relying on alternative fuel sources), fuel processing, or fuel handling facilities and are 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.

We also provide operation and maintenance services, including testing and start-up, to owners of electric generating facilities.

Unistar Nuclear

In 2005, we formed a joint enterprise with AREVA, Inc., to develop a standardized fleet of nuclear power plants based on an advanced design called the U.S. Evolutionary Power Reactor (U.S. EPR). We intend to work with AREVA, Inc. to obtain design certification and all necessary approvals from the NRC to license, construct, own, and operate U.S. EPR plants. Unistar Nuclear will offer the business framework that could enable the development of future joint ventures with Constellation Energy, other energy companies, and interested parties. Those future joint ventures, in turn, would license, construct, own, and operate nuclear power plants as part of a standardized fleet. However, prior to identifying specific projects or committing to ordering new nuclear power plants, our financial commitment will be limited to the formation of the business platform and business development activities, including early-stage licensing and permit activities.

Fuel Sources

Our power plants use diverse fuel sources. Our fuel mix based on capacity owned at December 31, 2005 and our generation based on actual output by fuel type in 2005 were as follows:

Fuel	Capacity Owned	Generation
Nuclear	32%	52%
Coal	23	30
Natural Gas	31	14
Oil	6	1
Renewable and Alternative (1)	4	2
Dual (2)	4	1

(1) Includes solar, geothermal, hydro, and biomass.

(2) Switches between natural gas and oil.

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

Nuclear

The output at our nuclear facilities over the past five years (including periods prior to our acquisition of Nine Mile Point and Ginna) is presented in the following table:

	Calvert Cliffs		Nine Mile Point		Ginna	
	MWH	Capacity Factor	MWH*	Capacity Factor	MWH	Capacity Factor
	(MWH in millions)					
2005	14.7	97%	12.7	93%	4.0	93%
2004	14.5	96	12.1	89	4.3	100
2003	13.7	93	12.2	90	3.9	90
2002	12.1	82	11.7	87	3.8	89
2001	13.6	92	11.6	86	4.3	100

*represents our proportionate ownership interest

The supply of fuel for nuclear generating stations includes the:

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

Uranium and Conversion	We have commitments for sufficient quantities of uranium (concentrates and uranium hexafluoride) to meet 100% of our total requirements through 2008. Additionally, we have commitments covering approximately 80% of our requirements in 2009 and 85% in 2010.
Enrichment	We have commitments that provide 100% of our uranium enrichment requirements through 2010 and 25% of these requirements in 2011 and 2012.

Fuel Assembly Fabrication	We have commitments for the fabrication of fuel assemblies for reloads required through 2013 for Nine Mile Point and Calvert Cliffs Nuclear Power Plant, Inc. (Calvert Cliffs), and through 2017 for Ginna.

The nuclear fuel markets are competitive, and although prices for uranium and conversion are increasing, we do not anticipate any significant problems in meeting our future requirements.

Storage of Spent Nuclear Fuel Federal Facilities

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

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

The DOE has stated that it will not meet that obligation until 2010 at the earliest. This delay has required that we undertake additional actions to provide on-site fuel storage at Calvert Cliffs, Ginna, and Nine Mile Point, including the installation of on-site dry fuel storage capacity at Calvert Cliffs, as described in more detail below. In 2004, complaints were filed against the federal government in the United States Court of Federal Claims seeking to recover damages caused by the DOE's failure to meet its contractual obligation to begin disposing of spent nuclear fuel by January 31, 1998. These cases are currently stayed, pending litigation in other related cases.

In connection with our purchase of Ginna, all of RG&E's rights and obligations related to recovery of damages from the DOE were assigned to us. However, we have an obligation to reimburse RG&E for up to the first $10 million of any recovered damages.

Storage of Spent Nuclear Fuel On-Site Facilities

Calvert Cliffs has a license from the NRC to operate an on-site independent spent fuel storage installation that expires in 2012. We have storage capacity at Calvert Cliffs that will accommodate spent fuel from operations through 2008. In addition, we can expand our temporary storage capacity at Calvert Cliffs to meet future requirements until approximately 2025. Currently, Nine Mile Point and Ginna do not have independent spent fuel storage capacity. Rather, Nine Mile Point's Unit 1 and Ginna have sufficient storage capacity within the plants until 2010. Nine Mile Point's Unit 2 has sufficient storage capacity within the plant until 2012. After that time, independent spent fuel storage capability may need to be developed at each site.

Cost for Decommissioning Uranium Enrichment Facilities

The Energy Policy Act of 1992 requires domestic nuclear utilities to contribute to a fund for decommissioning and decontaminating uranium enrichment facilities that had been operated by DOE. These contributions are generally payable over a 15-year period with escalation for inflation and are based upon the amount of uranium enriched by DOE for each utility through 1992. The 1992 Act provides that these costs are recoverable through utility service rates. BGE is solely responsible for these costs as they relate to Calvert Cliffs and will make the last payment in 2006. The sellers of the Nine Mile Point plant and the Long Island Power Authority are responsible for the costs relating to the Nine Mile Point plant. The seller of Ginna is responsible for the costs related to that facility.

Cost for Decommissioning

We are obligated to decommission our nuclear plants at the time these plants cease operation. Every two years, the NRC requires us to demonstrate reasonable assurance that funds will be available to decommission the sites. When BGE transferred all of its nuclear generating assets to our merchant energy business, it also transferred the trust fund established to pay for decommissioning Calvert Cliffs. At December 31, 2005, the trust fund assets were $370.4 million.

Under the Maryland Public Service Commission's (Maryland PSC) order regarding the deregulation of electric generation, BGE ratepayers must pay a total of $520 million, in 1993 dollars adjusted for inflation, to decommission Calvert Cliffs through fixed annual collections of approximately $18.7 million until June 30, 2006, and thereafter in an annual amount determined by reference to specified factors. We are required to submit a filing to the Maryland PSC by April 2006 to determine the annual amount BGE ratepayers will pay, if any, for decommissioning Calvert Cliffs after June 30, 2006. BGE is collecting this amount on behalf of Calvert Cliffs. Any costs to decommission Calvert Cliffs in excess of this $520 million must be paid by Calvert Cliffs. If BGE ratepayers have paid more than this amount at the time of decommissioning, Calvert Cliffs must refund the excess. If the cost to decommission Calvert Cliffs is less than the $520 million BGE's ratepayers are obligated to pay, Calvert Cliffs may keep the difference.

The sellers of Nine Mile Point transferred a $441.7 million decommissioning trust fund to us at the time of sale. In return, we assumed all liability for the costs to decommission Unit 1 and 82% of the costs to decommission Unit 2. We believe that this amount is adequate to cover our responsibility for decommissioning Nine Mile Point to a greenfield status (restoration of the site so that it substantially matches the natural state of the surrounding properties and the site's intended use). At December 31, 2005, the Nine Mile Point trust fund assets were $518.3 million.

The seller of Ginna transferred $200.8 million in decommissioning funds to us. In return, we assumed all liability for the costs to decommission the unit. We believe that this amount will be sufficient to cover our responsibility for decommissioning Ginna to a greenfield status. At December 31, 2005, the Ginna trust fund assets were $222.0 million.

Coal

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

	Approximate Annual Coal Requirement (tons)	**Special Coal Restrictions**
Brandon Shores Units 1 and 2 (combined)	3,500,000	Sulfur content less than 1.20 lbs per mmBTU
C. P. Crane Units 1 and 2 (combined)	850,000	Low ash melting temperature
H. A. Wagner Units 2 and 3 (combined)	1,100,000	Sulfur content no more than 1%

Coal deliveries to these facilities are made by rail and barge. We primarily use coal produced from mines located in central and northern Appalachia. 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.

During 2003, we expanded our coal sources including restructuring our rail contracts, increasing the range of coals we can consume, adding synthetic fuel as an alternate source, and finding potential other coal supply sources including shipments from Columbia, Venezuela, South Africa, and other international sources.

All of the Conemaugh and Keystone plants' annual coal requirements are purchased by the plant operators from regional suppliers on the open market. The sulfur restrictions on coal are approximately 2.3% for the Keystone plant and approximately 5.3% for the Conemaugh plant.

The annual coal requirements for the ACE, Jasmin, and Poso plants, which are located in California, are supplied under contracts with mining operators. The Jasmin and Poso plants are restricted to coal with sulfur content less than 4.0% and ACE is restricted to less than 2.0%.

All of our coal requirements reflect historical 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.

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 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

Under normal burn practices, our requirements for residual fuel oil (No. 6) amount to approximately 1.5 million to 2.0 million barrels of low-sulfur oil per year. Deliveries of residual fuel oil are made from the suppliers' Baltimore Harbor and Philadelphia marine terminals for distribution to the various generating plant locations. Also, based on normal burn practices, we require approximately 8.0 million to 11.0 million gallons of distillates (No. 2 oil and kerosene) annually, but these requirements can vary substantially from year to year depending upon the relationship between energy prices and fuel costs, weather conditions, and operating requirements. Distillates are purchased from the suppliers' Baltimore truck terminals for distribution to the various generating plant locations. We have contracts with various suppliers to purchase oil at spot prices, and for future delivery, to meet our requirements.

Competition

Market developments over the past several years have changed the nature of competition in the merchant energy business. Certain companies within the merchant energy sector have curtailed their activities or withdrawn completely from the business. However, new competitors (e.g., financial investors, banks and investment banks) have entered the market. We encounter competition from companies of various sizes, having varying levels of experience, financial and human resources, and differing strategies.

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

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

States are considering different types of regulatory initiatives concerning competition in the power industry, which makes a competitive assessment difficult. Increased competition that resulted from some of these initiatives in several states contributed in some instances to a reduction in electricity prices and put pressure on electric utilities to lower their costs, including the cost of purchased electricity. While many states continue to support retail competition and industry restructuring, other states that were considering deregulation have slowed their plans or postponed consideration of deregulation. In addition, other states are reconsidering deregulation.

We believe there is adequate growth potential in the current deregulated market and that further market changes could provide additional opportunities for our merchant energy business. Our wholesale marketing and risk management operation also participates in global coal sourcing activities by providing coal for the variable or fixed supply needs of North American and international power generators. In addition, our wholesale marketing and risk management operation provides products and services to upstream and downstream natural gas customers.

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

Merchant Energy Operating Statistics

	2005	2004	2003	2002	2001
Revenues *(In millions)*					
Mid-Atlantic Region	**$ 2,283.9**	$ 1,925.6	$ 1,696.2	$ 1,415.1	$ 1,379.2
Plants with Power Purchase Agreements	**829.6**	714.5	574.6	433.2	70.8
Competitive Supply Retail	**6,942.3**	4,280.0	2,567.7	312.7	
Competitive Supply Wholesale	**4,672.3**	3,353.8	2,703.9	540.7	233.5
Other	**58.0**	73.6	45.1	56.4	80.5
Total Revenues	**$ 14,786.1**	$ 10,347.5	$ 7,587.5	$ 2,758.1	$ 1,764.0
Generation *(In millions)* MWH	**60.2**	55.3	51.6	44.7	37.4

Operating statistics do not reflect the elimination of intercompany transactions.

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

Baltimore Gas and Electric Company

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

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

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

Electric Business

Electric Regulatory Matters and Competition

<u>Deregulation</u>

Effective July 1, 2000, electric customer choice and competition among electric suppliers was implemented in Maryland. As a result of the deregulation of electric generation, the following occurred:

All customers can choose their electric energy supplier.

BGE provided fixed-price standard offer service for commercial and industrial customers through either June 30, 2002 or June 30, 2004, depending on customer type. For the commercial and industrial customers that did not select an alternative supplier after those time periods, BGE provided a market-based standard offer service. Base rates for commercial and industrial customers were frozen until June 30, 2004.

Commercial and industrial customers have several service options that fix competitive transition charges (CTC) through June 30, 2006, at which time the CTC will be phased-out. CTC revenues were provided to allow BGE to recover stranded costs that resulted from the deregulation of BGE's generating assets.

BGE residential base rates for delivery service will not change before July 2006. Total residential base rates remain unchanged over the initial transition period (July 1, 2000 through June 30, 2006), as annual standard offer service rate increases are offset by corresponding decreases in the CTC that BGE receives from its customers.

While BGE does not sell electric commodity to all customers in its service territory, BGE continues to deliver electricity to all customers and provides meter reading, billing, emergency response, regular maintenance, and balancing services.

BGE transferred, at book value, its generating assets and related liabilities to the merchant energy business. At December 31, 2005, BGE remains contingently liable for the $269.8 million outstanding balance for liabilities transferred to the merchant energy business.

Standard Offer Service

BGE is providing fixed-price standard offer service for residential customers that do not select an alternative supplier through June 30, 2006. Beginning July 1, 2006, BGE's obligation to provide fixed-price standard offer service to residential customers will end, and all residential customers that receive their electric supply from BGE will be charged market-based standard offer service rates.

Since July 1, 2004, all commercial and industrial customers that receive their electric supply from BGE are charged market-based standard offer service rates. We discuss market-based standard offer service in more detail below.

Provider of Last Resort (POLR)
BGE is obligated to provide market-based standard offer service to residential customers from July 1, 2006 through May 31, 2010, and for commercial and industrial customers for varying periods beyond June 30, 2004, depending on customer load. The POLR rates charged during these time periods 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.

BGE's obligation to provide market-based standard offer service to its largest commercial and industrial customers expired on May 31, 2005. BGE continues to provide an hourly-priced market-based standard offer service to those customers.

In September 2005, the Maryland PSC issued an order extending POLR service through May 2007 for those commercial and industrial customers for which market-based standard offer service was scheduled to expire at the end of May 2006. The extended service will be provided on substantially the same terms as under the existing service, except that wholesale bidding for service to some customers will be conducted more frequently.

Bidding to supply BGE's market-based standard offer service to commercial and industrial customers beyond May 31, 2006, and to residential customers beyond June 30, 2006, will occur from time to time through a competitive bidding process approved by the Maryland PSC. Successful bidders, which may include subsidiaries of Constellation Energy, will execute contracts with BGE for varying terms depending on the load being served under the contract.

In early 2006, the Maryland PSC commenced a proceeding, and legislation was introduced in the Maryland General Assembly, to consider methods for requiring BGE to defer recovery of some of its costs of providing residential POLR service. These actions are a result of the anticipated increase in POLR prices expected to take place upon the expiration of the residential rate freeze in June 2006. Any decision by the Maryland PSC or legislation adopted by the Maryland General Assembly, that would defer recovery of, or would not allow BGE to fully recover its costs could have a material impact on our, and BGE's, financial results and liquidity.

We discuss the market risk of our regulated electric business in more detail in *Item 7. Management's Discussion and Analysis Market Risk* 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. We refer to these programs as active load management programs. These programs include:

- two options for commercial and industrial customers to voluntarily reduce their electric loads,
- air conditioning control for residential and commercial customers, and
- residential water heater control.

These programs generally take effect on summer days when demand and/or wholesale prices are relatively high and had the capability during the 2005 summer to reduce load up to approximately 238 MW.

Transmission and Distribution Facilities

BGE maintains approximately 250 substations and 1,300 circuit miles of transmission lines throughout central Maryland. BGE also maintains approximately 23,600 circuit miles of distribution lines. The transmission facilities are connected to those of neighboring utility systems as part of PJM. Under the PJM Tariff and various agreements, BGE and other market participants can use regional transmission facilities for energy, capacity, and ancillary services transactions including emergency assistance.

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

Electric Operating Statistics

	2005	2004	2003	2002	2001
Revenues *(In millions)*					
Residential	**$ 1,066.6**	$ 1,015.8	$ 959.0	$ 946.6	$ 885.3
Commercial					
Excluding Delivery Service Only	**722.1**	708.9	694.2	776.0	903.0
Delivery Service Only	**107.5**	78.6	66.1	33.5	
Industrial					
Excluding Delivery Service Only	**52.8**	92.3	137.0	158.7	218.1
Delivery Service Only	**28.0**	21.3	18.2	10.9	
System Sales and Deliveries	**1,977.0**	1,916.9	1,874.5	1,925.7	2,006.4
Other (A)	**59.5**	50.8	47.1	40.3	33.6
Total	**$ 2,036.5**	$ 1,967.7	$ 1,921.6	$ 1,966.0	$ 2,040.0
Distribution Volumes (*In thousands*) MWH					
Residential	**13,762**	13,313	12,754	12,652	11,714
Commercial					
Excluding Delivery Service Only	**7,847**	9,286	9,937	11,840	14,147
Delivery Service Only	**7,967**	5,767	4,982	2,762	
Industrial					
Excluding Delivery Service Only	**614**	1,429	2,556	3,478	4,445
Delivery Service Only	**3,122**	2,562	1,780	997	
Total	**33,312**	32,357	32,009	31,729	30,306
Customers *(In thousands)*					
Residential	**1,084.1**	1,072.1	1,061.7	1,052.3	1,040.5
Commercial	**114.7**	113.6	112.1	110.8	110.9
Industrial	**5.0**	4.8	4.9	4.9	5.0
Total	**1,203.8**	1,190.5	1,178.7	1,168.0	1,156.4

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

Operating statistics do not reflect the elimination of intercompany transactions.

"Delivery service only" refers to BGE's delivery of commodity that was purchased by the customer from an alternate supplier.

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.

In April 2005, BGE filed an application for a $52.7 million annual increase in its gas base rates. The Maryland PSC issued an order in December 2005 granting BGE an annual increase of $35.6 million. Certain parties to the proceeding have sought judicial review and Maryland PSC rehearing of the decision. BGE will not seek review of any aspect of the order. We cannot provide assurance that a court will not reverse any aspect of the order or that it will not remand certain issues to the Maryland PSC.

For customers that buy their gas from BGE, there is a market-based rates incentive mechanism. Under this market-based rates incentive mechanism, our actual cost of gas is compared to a market index (a measure of the market price of gas in a given period). The difference between our actual cost and the market index is shared equally between shareholders and customers. BGE must secure fixed-price contracts for at least 10%, but not more than 20%, of forecasted system supply requirements for the November through March period. These fixed-price contracts are not subject to sharing under the market-based rates incentive mechanism.

BGE purchases the natural gas it resells to customers directly from many producers and marketers. BGE has transportation and storage agreements that expire from 2006 to 2028.

BGE's current pipeline firm transportation entitlements to serve BGE's firm loads are 309,053 dekatherms (DTH) per day.

BGE's current maximum storage entitlements are 235,080 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 with 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 outside BGE's service territory. Earnings from these activities are shared between shareholders and customers. BGE makes these sales as part of a program to balance our supply of, and cost of, natural gas.

Gas Operating Statistics

	2005	2004	2003	2002	2001
Revenues *(In millions)*					
Residential					
Excluding Delivery Service Only	**$ 558.5**	$ 478.0	$ 444.5	$ 342.1	$ 378.4
Delivery Service Only	**23.2**	14.2	13.6	16.5	16.3
Commercial					
Excluding Delivery Service Only	**174.4**	135.4	128.6	89.4	115.5
Delivery Service Only	**31.9**	28.0	24.6	29.2	21.4
Industrial					
Excluding Delivery Service Only	**10.5**	9.4	11.5	9.3	12.8
Delivery Service Only	**12.4**	7.8	11.4	13.9	13.8
System Sales and Deliveries	**810.9**	672.8	634.2	500.4	558.2
Off-System Sales	**154.7**	77.2	84.8	74.8	113.6
Other	**7.2**	7.0	7.0	6.1	8.9
Total	**$ 972.8**	$ 757.0	$ 726.0	$ 581.3	$ 680.7
Distribution Volumes *(In thousands)* DTH					
Residential					
Excluding Delivery Service Only	**39,107**	39,080	40,894	35,364	33,147
Delivery Service Only	**5,423**	6,053	6,640	6,404	7,201
Commercial					
Excluding Delivery Service Only	**14,133**	13,248	13,895	11,583	12,334
Delivery Service Only	**28,993**	34,120	29,138	28,429	25,037
Industrial					
Excluding Delivery Service Only	**921**	865	1,143	1,207	1,386
Delivery Service Only	**19,357**	14,310	18,399	23,689	23,872
System Sales and Deliveries	**107,934**	107,676	110,109	106,676	102,977
Off-System Sales	**17,209**	9,914	12,859	18,551	20,012
Total	**125,143**	117,590	122,968	125,227	122,989
Customers *(In thousands)*					
Residential	**590.9**	582.0	575.2	567.3	558.7
Commercial	**42.0**	41.6	41.1	40.7	40.2
Industrial	**1.2**	1.2	1.2	1.3	1.4
Total	**634.1**	624.8	617.5	609.3	600.3

Operating statistics do not reflect the elimination of intercompany transactions.

"Delivery service only" refers to BGE's delivery of commodity 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 them to engage in their present business. Conditions of the franchises are satisfactory.

Other Nonregulated Businesses

Energy Projects and Services

We offer energy projects and services designed primarily to provide energy solutions to large commercial and industrial and governmental customers. These energy products and services include:

- designing, constructing, and operating heating, cooling, and cogeneration facilities,
- energy consulting and power-quality services,
- services to enhance the reliability of individual electric supply systems, and
- customized financing alternatives.

Home Products and Gas Retail Marketing

We offer services to customers in Maryland including:

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

Other

Our other nonregulated businesses include investments that we do not consider to be core operations. These include financial investments and real estate projects. While our intent is to dispose of these assets, market conditions and other events beyond our control may affect the actual sale of these assets. However, a future decline in the fair value of these assets could result in losses.

In the fourth quarter 2005, we sold our interests in our Panamanian distribution facility and the fund that holds interests in two South American energy projects. We discuss this sale in more detail in *Note 2 to the Consolidated Financial Statements.*

Consolidated Capital Requirements

Our total capital requirements for 2005 were $1,032 million. Of this amount, $741 million was used in our nonregulated businesses and $291 million was used in our regulated business. We estimate our total capital requirements will be $1,345 million in 2006.

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

Environmental Matters

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

We continuously monitor federal, state, and local environmental initiatives to determine potential impacts on our financial results. As new laws or regulations are promulgated, we assess their applicability and implement the necessary modifications to our facilities or their operation to maintain on-going compliance. Our capital expenditures were approximately $170 million during the five-year period 2001-2005 to comply with existing environmental standards and regulations. Our estimated environmental capital requirements for the next three years are approximately $40 million in 2006, $200 million in 2007, and $330 million in 2008.

Air Quality

The Clean Air Act created the basic framework for the federal and state regulation of air pollution. The cornerstone of the Act is the requirement that National Ambient Air Quality Standards be established to protect public health and public welfare. In addition, the Act also includes technology-driven emission requirements. Many of these provisions could materially affect our facilities and are described in more detail below.

National Ambient Air Quality Standards (NAAQS)

The NAAQS are federal air quality standards that establish maximum ambient air concentrations for the following specific pollutants: ozone (smog), carbon monoxide, lead, particulates, sulfur dioxides (SO_2), and nitrogen dioxides (NO_2). Our generating facilities are primarily affected by ozone and particulates standards. Ozone is formed when sunlight interacts with emissions of nitrogen oxides (NO_x) and volatile organic compounds (such as from motor vehicle exhaust). Our generating facilities are subject to various permits and programs meant to achieve or preserve attainment of the standards for all these pollutants.

In order for states to achieve compliance with the NAAQS, the Environmental Protection Agency (EPA) adopted the Clean Air Interstate Rule (CAIR) in March 2005 to further reduce ozone and fine particulate pollution by addressing the interstate transport of SO_2 and NO_x emissions from fossil fuel-fired generating facilities located primarily in the Eastern United States. The NO_x reduction requirements will be phased-in starting in 2009 with both annual and ozone season reduction requirements. The phase-in will be complete by 2015. The SO_2 reduction requirements will be phased-in starting in 2010 with the phase-in complete by 2015. According to the EPA, when fully implemented, CAIR will reduce SO_2 emissions in the affected states by over 70 percent and reduce NO_x emissions by over 60 percent from 2003 levels. Although CAIR provides the overall reduction requirements for SO_2 and NO_x, we do not yet know the impact on our facilities as that will be determined by the affected states in which our facilities operate.

Based on the information currently available to us about CAIR, 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 projects, which we expect will be approximately $40 million in 2006, $185 million in 2007, $300 million in 2008 and $200 million from 2009-2010. 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, 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. In addition, CAIR is subject to legal challenges filed by the states and industry and environmental groups. We cannot predict the timing or outcome of these challenges, or their possible effect on our financial results.

In May 2005, the EPA adopted a stricter NAAQS for ozone. States will be required to submit plans to the EPA to meet the new standard by 2007, at which time the standard will take effect. We are unable to determine the impact that complying with the stricter NAAQS for ozone will have on our financial results until the states in which our generating facilities are located adopt plans to meet the new standard. In transitioning to the stricter NAAQS for ozone, the EPA has delayed the requirement that states impose fees on generating facilities located in areas that have not met the NAAQS for ozone. Such fees could have been assessed on certain of our generating facilities located in Maryland and California beginning in 2006, but now will not be assessed prior to 2010.

In June 2005, the EPA finalized its rules relating to regional haze, which address emissions of SO_2, $NO_{x,}$ and particulate matter. However, adoption of CAIR by states is expected to meet the emissions reduction requirements under the regional haze rules. We expect Maryland and Pennsylvania, where we own several generating facilities, will, at a minimum, adopt CAIR. As a result, we believe the adoption of the regional haze rules by the EPA will not have a material effect on our financial results.

Several states in the northeastern U.S., including Maryland, continue to advocate for more stringent and earlier SO_2 and NO_x emissions reductions than those required under CAIR, the Clean Air Mercury Rule (CAMR), or other federally proposed legislative initiatives (such as the Bush Administration's Clear Skies proposal). These states have argued that such additional reductions are necessary to achieve compliance with the NAAQS for ozone and fine particulate matter by 2010.

In January 2006, the Maryland Department of the Environment (MDE) proposed the Clean Power Rule (CPR). In addition, a bill entitled the Healthy Air Act (HAA) was introduced in both houses of the Maryland legislature in January 2006. The CPR and the HAA would require more stringent and earlier reductions of SO_2, NO_x and mercury than required by CAIR and CAMR. The HAA also contains provisions for the reduction of carbon dioxide (CO_2) from coal-fired power plants in Maryland based upon concerns over global climate change. We are currently evaluating the potential impact of the CPR and the HAA on our environmental capital expenditure estimates and our financial results. While we do not know whether the CPR or the HAA will be enacted; if either is enacted, our compliance costs could be material.

Hazardous Air Emissions

The Clean Air Act requires the EPA to evaluate the public health impacts of hazardous air emissions from electric steam generating facilities. In March 2005, the EPA finalized regulations to reduce the emissions of mercury from coal-fired facilities. Under CAMR, the EPA has decided to regulate mercury through a market-based cap and trade program that will reduce nationwide utility emissions of mercury in two phases. The final CAMR does not address emissions of nickel and the EPA has not re-proposed regulating such emissions. The first phase of the program will begin in 2010. Additional mercury reductions will be required in the second phase of the program starting in 2018. According to the EPA, the CAMR will reduce mercury emissions from all affected coal-fired power plants by about 19 percent from 1999 levels in 2010, mostly from controls installed to comply with CAIR. The EPA expects total mercury reductions from all affected coal-fired plants of about 69 percent from 1999 levels by 2018.

The CAMR will affect all coal or waste coal fired boilers at our generating facilities. Although our planned capital expenditures for compliance with CAIR are anticipated to enable us to substantially meet the mercury reduction requirements under the first phase of the cap and trade program, the overall cost of compliance with the CAMR, including complying with the requirements under the second phase of the program, could be material. CAMR is subject to legal challenges filed by the states, industry, and environmental groups. We cannot predict the timing or outcome of these challenges, or their possible effect on our financial results. As discussed on the previous page, regulatory (CPR) and legislative proposals (HAA) in Maryland would require more stringent and earlier mercury reductions than required by CAMR. We are currently evaluating the potential impact of CAMR, CPR, and HAA on our financial results and on our environmental capital expenditure estimates.

New Source Review

The EPA and several states filed lawsuits against a number of coal-fired power plants primarily in Mid-Western and Southern states alleging violations of the Prevention of Significant Deterioration and Non-Attainment provisions of the Clean Air Act's new source review requirements. The EPA requested information relating to modifications made to our Brandon Shores, Crane, and Wagner plants located in Maryland. The EPA also sent similar, but narrower, information requests to two of our newer Pennsylvania waste-coal burning plants in which we have an ownership interest. We have responded to the EPA, and as of the date of this report the EPA has taken no further action.

Based on the level of emissions control that the EPA and states are seeking in these 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.

In August 2003, the EPA's equipment replacement rule was promulgated. The rule establishes an equipment replacement cost threshold for determining when major new source review requirements are triggered. The rule provides that plant owners may spend up to 20% of the replacement value of a generation unit on certain component replacements each year without triggering requirements for new pollution controls. A legal challenge to this rule was filed with the United States Court of Appeals and a stay was issued which delayed its effective date. The EPA has also determined to seek additional comment on certain features of the rule, including the 20% threshold. We cannot predict the timing or outcome of the legal challenge or the EPA comment process, or their possible effect on our financial results.

Global Climate Change

Future initiatives regarding greenhouse gas emissions and global warming continue to be the subject of much debate. As a result of our diverse fuel portfolio, our contribution to greenhouse gases varies by plant type. Fossil fuel-fired power plants are significant sources of CO_2 emissions, a principal greenhouse gas. Our compliance costs with any mandated federal greenhouse gas reductions in the future could be material.

Water Quality

The Clean Water Act established the basic framework for federal and state regulation of water pollution control. The Act requires facilities that discharge waste or storm water into the waters of the United States to obtain permits requiring them to meet effluent limits in order to achieve ambient water quality standards in the receiving waters. Under current provisions of the Clean Water Act, existing discharge permits are renewed every five years, at which time permit effluent limits come under extensive review and can be modified to account for more stringent regulations. In addition, the permits can be modified at any time.

Water Intake Regulations

In July 2004, the EPA published final rules under the Clean Water Act that require cooling water intake structures to reflect the best technology available for minimizing adverse environmental impacts. The final rules require the installation of additional intake screens or other protective measures, as well as extensive site-specific study and monitoring requirements. We currently have six facilities affected by the regulation. The rule allows for a number of compliance options that will be assessed through 2007, following which we will determine whether any action is required and what our most viable options are if any action is required. Until we determine our most viable option under the final rules, we cannot estimate our compliance costs. However, the costs associated with the final rules could be material.

Hazardous and Solid Waste

The Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) established the basic framework for federal and state regulations that can require any individual or entity that may have owned or operated a disposal site, as well as transporters or generators of hazardous substances sent to such site, to share in remediation costs. Except to the extent discussed in *Note 12 to the Consolidated Financial Statements*, compliance with CERCLA requirements is not expected to have a material adverse effect on our financial results.

The Resource Conservation and Recovery Act (RCRA) gives the EPA authority to control hazardous waste from "cradle-to-grave." This includes the generation, transportation, treatment, storage, and disposal of hazardous waste. RCRA also sets forth a framework for the management of non-hazardous wastes. Although RCRA focuses only on active and future facilities and, unlike CERCLA, does not address abandoned or historical sites, there are provisions that require phasing-out land disposal of hazardous waste, more stringent hazardous waste management standards, and a comprehensive underground storage tank program.

Our coal-fired generating facilities produce approximately two and a half million tons of combustion by-products ("ash") each year, including approximately 850,000 tons at our Maryland plants. Of the two and a half million tons, approximately 75% is beneficially re-used in various projects, including as structural fill in surface mine reclamation, and the remainder is placed in landfills. In 2000, the EPA decided not to regulate combustion ash as a hazardous waste under RCRA. Instead, the EPA announced its intention to develop national standards, currently scheduled to be proposed in June 2006, to regulate this material as a non-hazardous waste, and is developing regulations governing the placement of ash in landfills, surface impoundments, and sand/gravel surface mines. The EPA is also developing regulations for ash placement in coal mines, which are expected to be proposed in October 2007. Federal regulation has the potential to result in additional requirements such as groundwater monitoring, liners, and leachate collection and treatment systems for all landfills, surface impoundments, and sand and gravel mines used for ash management. Depending on the scope of any final requirements, our compliance costs could be material.

As a result of these regulatory proposals, the remaining ash placement capacity at our current mine reclamation site and our current ash generation projections, we are exploring our options for the placement of ash, including construction of an ash placement facility. Over the next five years, we estimate that our capital expenditures for this project will be approximately $75 million. Our estimates are subject to significant uncertainties including the timing of any regulatory change, its implementation timetable, and the scope of the final requirements. As a result, we cannot predict our capital spending or the scope and timing of this project with certainty, and the actual expenditures, scope and timing could differ significantly from our estimates.

Employees

Constellation Energy and its subsidiaries had approximately 9,850 employees at December 31, 2005. At the Nine Mile Point facility, approximately 680 employees are represented by the International Brotherhood of Electrical Workers, Local 97. The labor contract with this union expires in June 2006. We expect negotiations for a new contract to begin in May 2006. We expect to execute a new agreement with the union. We believe that our relationship with this union is satisfactory, but there can be no assurances that this will continue to be the case.

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.

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

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 operate 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. In addition, our business depends upon transmission facilities owned and operated by others; if transmission is disrupted or capacity is inadequate or unavailable, our ability to sell and deliver our wholesale power may be limited.

Currently, our power generation facilities purchase a portion of their fuel through short-term contracts or on the spot market. Fuel prices may also be volatile, and the price that can be obtained for power sales may not change at the same rate as changes in fuel costs. Also, our competitive energy businesses expose us to other risks, including credit risk and other risks relating to counterparties' failure to perform, and to the risk of commodity price fluctuations. Fuel price increases and defaults by suppliers and other counterparties may adversely affect our financial results.

Volatility in market prices for fuel and electricity may result from among other things:

- weather conditions,
- seasonality,
- electricity usage,
- illiquid markets,
- transmission or transportation constraints or inefficiencies,
- availability of competitively priced alternative energy sources,
- demand for energy commodities,
- available supplies of natural gas, crude oil and refined products, and coal,
- generating unit performance,
- natural disasters, terrorism, wars, embargoes and other catastrophic events,
- federal and state energy and environmental regulation, legislation and policies,
- geopolitical concerns affecting global supply of oil and natural gas, and
- general economic conditions, including downturns in the United States economy, which impact energy consumption.

In addition to the risks discussed above, risks specifically affecting our success in competitive wholesale markets include the ability to efficiently operate generating assets, maintenance of the qualifying facility status of certain projects, transmission and transportation availability, competition from new sources of generation, and the level of generation capacity. Our inability or failure to effectively hedge our assets or positions against changes in commodity prices, interest rates, counterparty credit risk, or other risk measures could significantly impact our future financial results.

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

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.

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

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

For example, the Environmental Protection Agency (EPA) recently adopted the Clean Air Interstate Rule (CAIR), which requires further reductions of sulfur dioxide and nitrogen oxide emissions from fossil fuel-fired plants located primarily in the Eastern United States, where many of our plants are located, and the Clean Air Mercury Rule (CAMR), which will regulate mercury emissions from coal-fired plants through a cap and trade program. In addition, the State of Maryland is considering requiring additional requirements to further reduce emissions of sulfur dioxide, nitrogen oxide, carbon dioxide, and mercury from generating facilities located in that state. Because CAIR and CAMR are still in the process of being implemented by the affected states and the additional Maryland requirements are in the proposal stage, we do not yet know the precise impact on our financial results. The capital expenditures and compliance costs with new air emission standards could be significantly greater than currently estimated.

The EPA also issued a rule under the Clean Water Act that will require certain of our plants to implement "best technology available" to minimize adverse effects to fish and shellfish from cooling water intake structures at those plants. The capital expenditures and compliance costs with the Clean Water Act intake requirements could be material to our financial results.

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 are exposed to risks relating to the ownership and operation of nuclear power plants.

We own and operate nuclear power plants. Ownership and operation of these plants expose us to risks in addition to those that result from owning and operating non-nuclear power generation facilities. Risks associated specifically with the operation and cost of operation of nuclear plants include changing federal and state environmental requirements relating specifically to nuclear facilities, safety, terrorism, accidents at the nuclear plants, storage and ultimate disposal of spent nuclear fuel, disposal of hazardous materials and waste, monitoring of discharges into the environment, and any required remediation of any site that is identified as contaminated.

Any of these risks could result in substantial liabilities or expenses for us and reduce our earnings or harm our liquidity. In addition, the Nuclear Regulatory Commission (NRC) has the authority to modify, suspend or revoke the operating license for any of our nuclear power facilities if it determines that such action is necessary to ensure the public health and safety. Such action would have a negative impact on our financial results.

In the event of a nuclear accident at one of our nuclear plants, the cost of property damage and other expenses incurred may exceed our insurance coverage available from both private sources and an industry mutual insurance company. In addition, in the event of an accident at one of our or another participating insured party's nuclear plants, we could be assessed retrospective insurance premiums. Uninsured losses or the payment of retrospective insurance premiums could each have a material adverse effect on our financial results.

BGE may not be able to recover costs incurred in satisfying its provider of last resort (POLR) obligations, which may adversely affect our, or BGE's, financial results and liquidity.

Under the electric restructuring the state of Maryland enacted in 1999 and various settlements approved by the Maryland Public Service Commission (Maryland PSC) in 2003 and 2005, BGE is obligated to serve as the POLR for all retail customers in its service territories for various periods ending between 2007 and 2010. POLR obligations are the obligations of energy delivery businesses to provide electricity to customers that do not choose a competitive supplier and, by their nature, are difficult to quantify.

As the POLR supplier, BGE is required to secure load requirements through a wholesale bidding process sufficient to serve those customers in its service territory in the event that customers do not choose alternate suppliers or if a third-party supplier is unable to satisfy its obligations. The settlements provide that BGE be able to recover all of its supply and certain other actual costs of providing POLR service.

However, in early 2006, the Maryland PSC commenced a proceeding, and legislation was introduced in the Maryland General Assembly, to consider methods for requiring BGE to defer recovery of some of its costs of providing residential POLR service. These actions are a result of the anticipated increase in POLR prices expected to take place upon the expiration of the residential rate freeze in June 2006. Any decision by the Maryland PSC, or legislation adopted by the Maryland General Assembly, that would defer recovery of, or would not allow BGE to fully recover its costs could have a material impact on our financial results and liquidity.

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

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

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

Over the past several years, several merchant energy businesses 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. While we have seen recent improvements in liquidity, future reductions in liquidity may restrict our ability to manage our risks, and could impact our financial results.

We may not fully hedge our generation assets, competitive supply 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. 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.

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.

We are exposed to the risk of loss from counterparties' nonperformance. Nonperformance could be failure to provide energy or failure to pay for energy we provide a counterparty. Should counterparties fail to provide energy, we might be forced to enter into alternative arrangements or honor the underlying commitment at then-current market prices, which may result in higher costs to us. If the counterparties fail to pay for energy we provided, then our liquidity and financial results may be negatively impacted.

In connection with our operations, we have, and will continue to, guarantee or indemnify the performance of a portion of the obligations of our subsidiaries. Some of these guarantees and indemnities are for fixed amounts, others have a fixed maximum amount, and others do not specify a maximum amount. We might not be able to satisfy all of these guarantees and indemnification obligations if they were to come due at the same time.

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

The regulatory environment applicable to the electric and gas industries has undergone substantial changes over the past several years 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 gas industries and the manner in which their participants conduct business. We have targeted the deregulated segments of the electric and gas industries created by these initiatives. These changes are ongoing and we cannot predict the future development of deregulation in these markets or the ultimate effect that this changing regulatory environment will have on our business.

Moreover, existing regulations may be revised or reinterpreted, new laws and regulations may be adopted or become applicable to us or our facilities, and future changes in laws and regulations may have a detrimental effect on our business. Certain restructured markets (most notably California) have experienced supply problems and price volatility in the past. These supply problems and volatility have been the subject of a significant amount of publicity, much of which has been critical of the restructuring initiatives. In some of these markets, including California, proposals have been made by governmental agencies and/or other interested parties to re-regulate areas of these markets which have previously been deregulated. Other proposals to re-regulate may be made and legislative or other attention to the electric and gas restructuring process may delay or reverse the deregulation process. If competitive restructuring of the electric and gas markets is reversed, discontinued or delayed, 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 depend on transportation and transmission facilities owned and operated by utilities and other energy companies to deliver the electricity, coal, and natural gas we sell to the wholesale and retail markets, as well as the natural gas and coal we purchase to supply some of our generating facilities. The Federal Energy Regulatory Commission (FERC) requires wholesale electric transmission services to be offered on an open access, non-discriminatory basis. However, sufficient transmission services are not always available. If transportation or transmission is disrupted, or transportation or transmission capacity is inadequate, our ability to sell and deliver products may be hindered. Such disruptions could also hinder our providing electricity or natural gas to our retail electric and gas customers and may materially adversely affect our financial results.

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

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

Our financial results may fluctuate on a seasonal and quarterly basis.

Our business is affected by seasonal weather conditions. Consequently, 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.

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

We rely on access to capital markets as a source of liquidity for capital requirements not satisfied by operating cash flows. If any of our credit ratings were to be downgraded, especially below investment grade, our ability to raise capital on favorable terms, including the commercial paper markets, could be hindered, and our borrowing costs would increase. Additionally, the business prospects of our wholesale and retail competitive supply businesses, which in many cases rely on the creditworthiness of Constellation Energy, would be negatively impacted. Some of the factors that affect credit ratings are cash flows, liquidity, and the amount of debt as a component of total capitalization.

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

We are subject to regulation under environmental laws, the Federal Power Act, the Atomic Energy Act of 1954 and the Energy Policy Act of 2005, and certain sections of Maryland and other state statutes relating to public utilities, and the operation of electric or natural gas facilities. Changing governmental policies and regulatory actions can have a significant impact on us, including those of FERC, the NRC, the Maryland PSC, and the utility commissions of other states in which we have operations. State and Federal regulations can impact, among other things, the following:

- allowed rates of return,
- industry and rate structure,
- operation of nuclear power plants,
- operation and construction of plant facilities,
- operation and construction of transmission facilities,
- acquisition, disposal, depreciation and amortization of assets and facilities,
- transactions between subsidiaries and affiliates,
- recovery of fuel and purchased power costs,
- recovery of storm-related repair costs,
- decommissioning costs,
- return on common equity and equity ratio limits,
- payment of dividends, and
- present or prospective wholesale and retail competition (including but not limited to retail choice and transmission costs).

Certain regulatory commissions also have the authority to disallow recovery of any and all costs that they consider excessive or imprudently incurred. In addition, BGE holds franchise agreements with local municipalities and counties, and must renegotiate expiring agreements. These factors may have a negative impact on our business and financial results.

BGE's Maryland distribution rates are subject to regulation by the Maryland PSC, and such rates are effective until new base rates are approved. In addition, limited categories of costs are recovered through adjustment charges that are periodically reset to reflect current costs. Inability to recover material costs not included in base rates or adjustment clauses, including increases in uncollectible customer accounts that may result from higher gas and/or electric costs, could have an adverse effect on our financial results.

As a result, the regulatory process may restrict our ability to grow earnings in certain parts of our business, can cause delays in or affect business planning and transactions, can increase our costs, and does not provide any assurance as to achievement of earnings levels.

We operate in a changing market environment influenced by various legislative and regulatory initiatives regarding deregulation, regulation or restructuring of the energy industry, including deregulation of the production and sale of electricity. We will need to adapt to these changes, which could restrict our ability to continue to grow our nonregulated businesses. In addition, we may face increasing competitive pressures in our nonregulated businesses.

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

liquidity and financial results.

Our qualified pension obligations have exceeded the fair value of our plan assets since 2001. At December 31, 2005, our qualified pension obligations were $345.1 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 may increase our funding requirements for these obligations, which may adversely affect our liquidity and financial results.

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

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

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

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

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

We are subject to employee workforce factors, including loss or retirement of key executives or other employees, availability of qualified personnel, collective bargaining agreements with union employees, and work stoppage that could affect our financial results.

We may be unable to obtain the approvals required to complete our merger with FPL Group Inc. (FPL Group) or, in order to do so, the combined company may be required to comply with material restrictions or conditions.

On December 19, 2005, we announced the execution of a merger agreement with FPL Group. Before the merger may be completed, shareholder approval will have to be obtained by us and by FPL Group. In addition, various filings must be made with FERC, NRC and various utility regulatory, antitrust and other authorities in the United States. These governmental authorities may impose conditions on the completion, or require changes to the terms, of the merger, including restrictions or conditions on the business, operations, or financial performance of the combined company following completion of the merger. These conditions or changes could have the effect of delaying completion of the merger or imposing additional costs on or limiting the revenues of the combined company following the merger, which could have a material adverse effect on the financial results of the combined company and/or cause either us or FPL Group to abandon the merger.

If we are unable to complete the merger, we still will incur and will remain liable for significant transaction costs, including legal, accounting, financial advisory, filing, printing and other costs relating to the merger whether or not it is completed, which we estimate to be approximately $40 million. Also, depending upon the reasons for not completing the merger, including whether we have received or entered into a competing takeover proposal, we may be required to pay FPL Group a termination fee of up to $425 million. The occurrence of either of these events individually or in combination could have a material adverse affect on our financial results.

If completed, our merger with FPL Group may not achieve its intended results.

We and FPL Group entered into the merger agreement with the expectation that the merger would result in various benefits, including, among other things, cost savings and operating efficiencies primarily relating to the nonregulated businesses. Achieving the anticipated benefits of the merger is subject to a number of uncertainties, including whether the businesses of Constellation Energy and FPL Group are integrated in an efficient and effective manner. Failure to achieve these anticipated benefits could result in increased costs, decreases in the amount of expected revenues generated by the combined company and diversion of management's time and energy and could have an adverse effect on the combined company's business, financial results and prospects.

We will be subject to business uncertainties and contractual restrictions while the merger with FPL Group is pending that could adversely affect our financial results.

Uncertainty about the effect of the merger with FPL Group on employees and customers may have an adverse effect on us. Although we intend to take steps designed to reduce any adverse effects, these uncertainties may impair our ability to attract, retain and motivate key personnel until the merger is completed and for a period of time thereafter, and could cause customers, suppliers and others that deal with us to seek to change existing business relationships.

Employee retention and recruitment may be particularly challenging prior to the completion of the merger, as employees and prospective employees may experience uncertainty about their future roles with the combined company. If, despite our retention and recruiting efforts, key employees depart or fail to accept employment with us because of issues relating to the uncertainty and difficulty of integration or a desire not to remain with the combined company, our financial results could be affected.

The pursuit of the merger and the preparation for the integration of Constellation Energy and FPL Group may place a significant burden on management and internal resources. The diversion of management attention away from day-to-day business concerns and any difficulties encountered in the transition and integration process could affect our financial results.

In addition, the merger agreement restricts us, without FPL Group's consent, from making certain acquisitions and taking other specified actions until the merger occurs or the merger agreement terminates. These restrictions may prevent us from pursuing otherwise attractive business opportunities and making other changes to our business prior to completion of the merger or termination of the merger agreement.

Item 2. Properties

Constellation Energy's corporate offices occupy approximately 106,000 square feet of leased office space in Baltimore, Maryland. The corporate offices for most of our merchant energy business occupy approximately 224,000 square feet of leased office space in another building 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. In January 2004, BGE sold a portion of its headquarters building and is in the process of consolidating its operations into the remainder of the building. 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.

All of BGE's property is subject to the lien of BGE's mortgage securing its mortgage bonds. All of the generation facilities transferred to our subsidiaries by BGE on July 1, 2000, along with the stock we own in certain of our subsidiaries, are subject to the lien of BGE's mortgage.

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.

We also lease office space throughout North America, in the United Kingdom, and in Australia to support our merchant energy business.

The following table describes our generating facilities:

Plant	Location	Installed Capacity (MW)	% Owned	Capacity Owned (MW)	Primary Fuel
			(at December 31, 2005)		
Mid-Atlantic Region					
Calvert Cliffs	Calvert Co., MD	1,735	100.0	1,735	Nuclear
Brandon Shores	Anne Arundel Co., MD	1,286	100.0	1,286	Coal
H. A. Wagner	Anne Arundel Co., MD	1,001	100.0	1,001	Coal/Oil/Gas
C. P. Crane	Baltimore Co., MD	399	100.0	399	Oil/Coal
Keystone	Armstrong and Indiana Cos., PA	1,711	21.0	358 (A)	Coal
Conemaugh	Indiana Co., PA	1,711	10.6	181 (A)	Coal
Perryman	Harford Co., MD	360	100.0	360	Oil/Gas
Big Sandy	Neal, WV	300	100.0	300	Gas
Wolf Hills	Bristol, VA	250	100.0	250	Gas
Riverside	Baltimore Co., MD	249	100.0	249	Oil/Gas
Handsome Lake	Rockland Twp, PA	250	100.0	250	Gas
Notch Cliff	Baltimore Co., MD	128	100.0	128	Gas
Westport	Baltimore City, MD	121	100.0	121	Gas
Philadelphia Road	Baltimore City, MD	64	100.0	64	Oil
Safe Harbor	Safe Harbor, PA	416	66.7	278	Hydro
Total Mid-Atlantic Region		9,981		6,960	
Plants with Power Purchase Agreements					
High Desert	Victorville, CA	830	100.0	830	Gas
Nine Mile Point Unit 1	Scriba, NY	620	100.0	620	Nuclear
Nine Mile Point Unit 2	Scriba, NY	1,148	82.0	941	Nuclear
R.E. Ginna	Ontario, NY	498	100.0	498	Nuclear
University Park	Chicago, IL	300	100.0	300	Gas
Total Plants with Power Purchase Agreements		3,396		3,189	
Competitive Supply					
Rio Nogales	Seguin, TX	800	100.0	800	Gas
Holland Energy	Shelby Co., IL	665	100.0	665	Gas
Total Competitive Supply		1,465		1,465	
Other					
Panther Creek	Nesquehoning, PA	83	50.0	42	Waste Coal
Colver	Colver Township, PA	110	25.0	28	Waste Coal
Sunnyside	Sunnyside, UT	53	50.0	26	Waste Coal
ACE	Trona, CA	102	31.1	32	Coal
Jasmin	Kern Co., CA	33	50.0	17	Coal
POSO	Kern Co., CA	33	50.0	17	Coal
Mammoth Lakes G-1	Mammoth Lakes, CA	6	50.0	3	Geothermal
Mammoth Lakes G-2	Mammoth Lakes, CA	12	50.0	6	Geothermal
Mammoth Lakes G-3	Mammoth Lakes, CA	12	50.0	6	Geothermal
Soda Lake I	Fallon, NV	4	50.0	2	Geothermal
Soda Lake II	Fallon, NV	10	50.0	5	Geothermal
Rocklin	Placer Co., CA	24	50.0	12	Biomass
Fresno	Fresno, CA	24	50.0	12	Biomass
Chinese Station	Jamestown, CA	22	45.0	10	Biomass
Malacha	Muck Valley, CA	32	50.0	16	Hydro
SEGS IV	Kramer Junction, CA	30	12.2	4	Solar
SEGS V	Kramer Junction, CA	30	4.2	1	Solar
SEGS VI	Kramer Junction, CA	30	8.8	3	Solar
Total Other		650		242	
Total Generating Facilities		15,492		11,856	

Plant	Location	Installed Capacity (MW)	% Owned	Capacity Owned (MW)	Primary Fuel

(A) 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.

The following table describes our processing facilities:

Plant	Location	% Owned	Primary Fuel
A/C Fuels	Hazelton, PA	50.0	Coal Processing
Gary PCI	Gary, IN	24.5	Coal Processing
Low Country	Cross, SC	99.0	Synfuel Processing
PC Synfuel VA I	Norton, VA	16.7	Synfuel Processing
PC Synfuel WV I	Chelyan, WV	16.7	Synfuel Processing
PC Synfuel WV II	Mount Storm, WV	16.7	Synfuel Processing
PC Synfuel WV III	Chester, VA	16.7	Synfuel Processing

Item 3. Legal Proceedings

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

Item 4. Submission of Matters to Vote of Security Holders

Not applicable.

Executive Officers of the Registrant

Name	Age	Present Office	Other Offices or Positions Held During Past Five Years
Mayo A. Shattuck III	51	Chairman of the Board of Constellation Energy (since July 2002), President and Chief Executive Officer of Constellation Energy (since November 2001); and Chairman of the Board of BGE (since July 2002)	Global Head of Investment Banking and Global Head of Private Banking Deutsche Banc Alex. Brown.
E. Follin Smith	46	Executive Vice President (since January 2004), Chief Financial Officer (since June 2001) and Chief Administrative Officer (since January 2004) of Constellation Energy; and Senior Vice President and Chief Financial Officer of Baltimore Gas and Electric Company (since January 2002)	Senior Vice President Constellation Energy; and Senior Vice President and Chief Financial Officer Armstrong Holdings, Inc.
Thomas V. Brooks	43	Chairman of Constellation Energy Commodities Group, Inc. (since August 2005); Vice Chairman (since August 2005) and Executive Vice President of Constellation Energy (since January 2004)	President Constellation Energy Commodities Group, Inc.; Executive Vice President Constellation Energy; Vice President of Business Development and Strategy Constellation Energy; and Vice President Goldman Sachs.
Michael J. Wallace	58	President of Constellation Generation Group, LLC (since January 2002); Executive Vice President of Constellation Energy (since January 2004)	Managing Director and Member Barrington Energy Partners.
Thomas F. Brady	56	Executive Vice President, Corporate Strategy and Retail Competitive Supply of Constellation Energy (since January 2004)	Senior Vice President, Corporate Strategy and Development Constellation Energy; and Vice President, Corporate Strategy and Development Constellation Energy.

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Irving B. Yoskowitz	60	Executive Vice President and General Counsel of Constellation Energy (since June 2005)	Senior Counsel Crowell & Moring (law firm); Senior Partner Global Technology Partners, LLC (investment banking and consulting firm); and Senior Advisor Akin Gump Strauss Hauer Feld LLP (law firm).
Felix J. Dawson	38	Co-President and Co-Chief Executive Officer of Constellation Energy Commodities Group, Inc. (since August 2005)	Co-Chief Commercial Officer Constellation Energy Commodities Group, Inc.; Managing Director Constellation Energy Commodities Group, Inc.; Managing Director, Co-Head Origination Constellation Energy Commodities Group, Inc.; and Vice President Goldman Sachs Power, LLC.
George E. Persky	36	Co-President and Co-Chief Executive Officer of Constellation Energy Commodities Group, Inc. (since August 2005)	Co-Chief Commercial Officer Constellation Energy Commodities Group, Inc.; Managing Director Constellation Energy Commodities Group, Inc.; Manager, Business Development and Strategy Constellation Energy; and Associate, Goldman Sachs.
Kenneth W. DeFontes, Jr.	55	President and Chief Executive Officer of Baltimore Gas and Electric Company and Senior Vice President of Constellation Energy (since October 2004)	Vice President, Electric Transmission and Distribution BGE.
Paul J. Allen	54	Senior Vice President, Corporate Affairs of Constellation Energy (since January 2004)	Vice President, Corporate Affairs Constellation Energy; and Senior Vice President and Group Head Ogilvy Public Relations.
John R. Collins	48	Senior Vice President (since January 2004) and Chief Risk Officer of Constellation Energy (since December 2001)	Vice President Constellation Energy; Managing Director Finance Constellation Power Source Holdings, Inc.; and Managing Director and Senior Financial Officer Constellation Energy Commodities Group, Inc.
Beth S. Perlman	45	Senior Vice President (since January 2004) and Chief Information Officer of Constellation Energy (since April 2002)	Vice President, Technology Enron Corporation.
Marc L. Ugol	47	Senior Vice President, Human Resources of Constellation Energy (since January 2004)	Vice President, Human Resources Constellation Energy; and Senior Vice President, Human Resources and Administration Tellabs, Inc.

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

PART II

Item 5. Market for Registrant's Common Equity and Related Shareholder Matters

Stock Trading

Constellation Energy's common stock is traded under the ticker symbol CEG. It is listed on the New York, Chicago, and Pacific stock exchanges. It has unlisted trading privileges on the Boston, Cincinnati, and Philadelphia exchanges.

As of January 31, 2006, there were 43,709 common shareholders of record.

Dividend Policy

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

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

In January 2006, we announced an increase in our quarterly dividend from $0.335 to $0.3775 per share payable April 3, 2006 to holders of record on March 10, 2006. This is equivalent to an annual rate of $1.51 per share.

Quarterly dividends were declared on our common stock during 2005 and 2004 in the amounts set forth below.

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

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

Common Stock Dividends and Price Ranges

	2005			2004		
		Price*			Price*	
	Dividend Declared	High	Low	Dividend Declared	High	Low
First Quarter	$ 0.335	$ 53.55	$ 43.01	$ 0.285	$ 41.47	$ 38.52
Second Quarter	0.335	57.91	50.36	0.285	41.35	35.89
Third Quarter	0.335	62.09	56.50	0.285	41.18	36.76
Fourth Quarter	0.335	62.60	50.40	0.285	44.90	39.90
Total	$ 1.340			$ 1.140		

* Based on New York Stock Exchange Composite Transactions.

Unregistered Sales of Equity Securities and Use of Proceeds

The following table presents shares surrendered by employees to exercise stock options and to satisfy tax withholding obligations on vested restricted stock and stock option exercises.

Period	Total Number of Shares Purchased	Average Price Paid for Shares	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares that May Yet Be Purchased Under the Plans and Programs
October 1 October 31, 2005	889	$ 55.88		
November 1 November 30, 2005	123	51.70		
December 1 December 31, 2005	1,982,414	58.33		
Total	1,983,426	$ 58.33		

Item 6. Selected Financial Data

Constellation Energy Group, Inc. and Subsidiaries

	2005	2004	2003	2002(1)	2001
			(In millions, except per share amounts)		
Summary of Operations					
Total Revenues	**$ 17,132.0**	$ 12,286.4	$ 9,454.1	$ 4,771.6	$ 3,683.0
Total Expenses	**16,073.9**	11,261.2	8,431.0	3,711.5	3,267.3
Income From Operations	**1,058.1**	1,025.2	1,023.1	1,060.1	415.7
Other Income	**62.8**	25.3	20.7	33.8	0.8
Fixed Charges	**310.1**	326.8	336.5	277.3	236.0
Income Before Income Taxes	**810.8**	723.7	707.3	816.6	180.5
Income Taxes	**204.1**	156.9	250.6	301.2	61.3
Income from Continuing Operations and Before Cumulative Effects of Changes in Accounting Principles	**606.7**	566.8	456.7	515.4	119.2
Income (Loss) from Discontinued Operations, Net of Income Taxes	**23.6**	(27.1)	19.0	10.2	(36.8)
Cumulative Effects of Changes in Accounting Principles, Net of Income Taxes	**(7.2)**		(198.4)		8.5
Net Income	**$ 623.1**	$ 539.7	$ 277.3	$ 525.6	$ 90.9
Earnings Per Common Share from Continuing Operations and Before Cumulative Effects of Changes in Accounting Principles Assuming Dilution	**$ 3.38**	$ 3.28	$ 2.74	$ 3.14	$ 0.75
Income (Loss) from Discontinued Operations	**0.13**	(0.16)	0.11	0.06	(0.23)
Cumulative Effects of Changes in Accounting Principles	**(0.04)**		(1.19)		0.05
Earnings Per Common Share Assuming Dilution	**$ 3.47**	$ 3.12	$ 1.66	$ 3.20	$ 0.57
Dividends Declared Per Common Share	**$ 1.34**	$ 1.14	$ 1.04	$ 0.96	$ 0.48
Summary of Financial Condition					
Total Assets	**$ 21,473.9**	$ 17,347.1	$ 15,593.0	$ 14,943.3	$ 14,697.5
Short-Term Borrowings	**$ 0.7**	$	$ 9.6	$ 10.5	$ 975.0
Current Portion of Long-Term Debt	**$ 491.3**	$ 480.4	$ 343.2	$ 426.2	$ 1,406.7
Capitalization					
Long-Term Debt	**$ 4,369.3**	$ 4,813.2	$ 5,039.2	$ 4,613.9	$ 2,712.5

	2005	2004	2003	2002(1)	2001
Minority Interests	**22.4**	90.9	113.4	105.3	101.7
Preference Stock Not Subject to Mandatory Redemption	**190.0**	190.0	190.0	190.0	190.0
Common Shareholders' Equity	**4,915.5**	4,726.9	4,140.5	3,862.3	3,843.6
Total Capitalization	**$ 9,497.2**	$ 9,821.0	$ 9,483.1	$ 8,771.5	$ 6,847.8
Financial Statistics at Year End					
Ratio of Earnings to Fixed Charges	**3.38**	3.02	2.90	3.31	1.39
Book Value Per Share of Common Stock	**$ 27.57**	$ 26.81	$ 24.68	$ 23.44	$ 23.48

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

(1) Total revenues for the year ended December 31, 2002 include $255.5 million of gains recognized on the sale of our outstanding shares of Orion Power Holdings, Inc.

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

Baltimore Gas and Electric Company and Subsidiaries

	2005	2004	2003	2002	2001
			(In millions)		
Summary of Operations					
Total Revenues	**$ 3,009.3**	$ 2,724.7	$ 2,647.6	$ 2,547.3	$ 2,720.7
Total Expenses	**2,612.8**	2,353.3	2,262.6	2,181.0	2,408.9
Income From Operations	**396.5**	371.4	385.0	366.3	311.8
Other Income (Expense)	**5.9**	(6.4)	(5.4)	10.7	0.4
Fixed Charges	**93.5**	96.2	111.2	140.6	154.6
Income Before Income Taxes	**308.9**	268.8	268.4	236.4	157.6
Income Taxes	**119.9**	102.5	105.2	93.3	60.3
Net Income	**189.0**	166.3	163.2	143.1	97.3
Preference Stock Dividends	**13.2**	13.2	13.2	13.2	13.2
Earnings Applicable to Common Stock	**$ 175.8**	$ 153.1	$ 150.0	$ 129.9	$ 84.1
Summary of Financial Condition					
Total Assets	**$ 4,742.1**	$ 4,662.9	$ 4,706.6	$ 4,779.9	$ 4,954.5
Current Portion of Long-Term Debt	**$ 469.6**	$ 165.9	$ 330.6	$ 420.7	$ 666.3
Capitalization					
Long-Term Debt	**$ 1,015.1**	$ 1,359.5	$ 1,343.7	$ 1,499.1	$ 1,821.7
Minority Interest	**18.3**	18.7	18.9	19.4	5.0
Preference Stock Not Subject to Mandatory Redemption	**190.0**	190.0	190.0	190.0	190.0
Common Shareholder's Equity	**1,622.5**	1,566.0	1,487.7	1,461.7	1,131.4
Total Capitalization	**$ 2,845.9**	$ 3,134.2	$ 3,040.3	$ 3,170.2	$ 3,148.1
Financial Statistics at Year End					
Ratio of Earnings to Fixed Charges	**4.22**	3.75	3.36	2.66	1.99
Ratio of Earnings to Fixed Charges and Preferred and Preference Stock Dividends	**3.45**	3.08	2.82	2.31	1.75

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

Introduction and Overview

Constellation Energy Group, Inc. (Constellation Energy) is an energy company that conducts its business through various subsidiaries including a merchant energy business and Baltimore Gas and Electric Company (BGE). We describe our operating segments in *Note 3*.

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

In this discussion and analysis, we will explain the general financial condition and the results of operations for Constellation Energy and BGE including:

- factors which affect our businesses,
- our earnings and costs in the periods presented,
- changes in earnings and costs between periods,
- sources of earnings,
- impact of these factors on our overall financial condition,
- expected future expenditures for capital projects, and
- expected sources of cash for future capital expenditures.

As you read this discussion and analysis, refer to our Consolidated Statements of Income, which present the results of our operations for 2005, 2004, and 2003. We analyze and explain the differences between periods in the specific line items of our Consolidated Statements of Income.

We have organized our discussion and analysis as follows:

- First, we discuss our strategy.
- We then describe the business environment in which we operate including how regulation, weather, and other factors affect our business.
- Next, we discuss our critical accounting policies. These are the accounting policies that are most important to both the portrayal of our financial condition and results of operations and require management's most difficult, subjective or complex judgment.
- We highlight significant events that are important to understanding our results of operations and financial condition.
- We then review our results of operations beginning with an overview of our total company results, followed by a more detailed review of those results by operating segment.
- We review our financial condition addressing our sources and uses of cash, security ratings, capital resources, capital requirements, commitments, and off-balance sheet arrangements.
- We conclude with a discussion of our exposure to various market risks.

Pending Merger with FPL Group, Inc.

In order to further our strategies discussed below, we entered into an Agreement and Plan of Merger with FPL Group, Inc. (FPL Group). We discuss our pending merger with FPL Group in more detail in *Note 15*.

Strategy

We are pursuing a strategy of providing energy and energy related services through our competitive supply activities and BGE, our regulated utility located in Maryland. Our merchant energy business focuses on short-term and long-term purchases and sales of energy, capacity, and related products to various customers, including distribution utilities, municipalities, cooperatives, industrial customers, and commercial customers.

We obtain this energy through both owned and contracted supply resources. Our generation fleet is strategically located in deregulated markets across the country and is diversified by fuel type, including nuclear, coal, gas, oil, and renewable sources. In addition to owning generating facilities, we contract for power from other merchant providers, typically through power purchase agreements. We intend to remain diversified between regulated transmission and distribution and competitive supply. We will use both our owned generation and our contracted generation to support our competitive supply operations.

We are a leading national competitive supplier of energy. In our wholesale and commercial and industrial retail marketing activities we are leveraging our recognized expertise in providing full requirements energy and energy related services to enter markets, capture market share, and organically grow these businesses. Through the application of technology, intellectual capital, process improvement, and increased scale, we are seeking to reduce the cost of delivering full requirements energy and energy related services and managing risk.

We are also responding proactively to customer needs by expanding the variety of products we offer. Our wholesale competitive supply activities include a growing operation that markets physical energy products and risk management and logistics services to generators, distributors, producers of coal, natural gas and fuel oil, and other consumers.

As part of our risk management activities, we trade energy and energy-related commodities and deploy risk capital in the management of our portfolio in order to earn additional returns. These activities are managed through daily value at risk and stop loss limits and liquidity guidelines.

Within our retail competitive supply activities, we are marketing a broader array of products and expanding our markets. Over time, we may consider integrating the sale of electricity and natural gas to provide one energy procurement solution for our customers.

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

To achieve our strategic objectives, we expect to continue to pursue opportunities that expand our access to customers and to support our wholesale marketing and risk management operation with generation assets that have diversified geographic, fuel, and dispatch characteristics. We also expect to grow through buying and selling a greater number of physical energy products and services to large energy customers. We expect to achieve operating efficiencies within our competitive supply operation and our generation fleet by selling more products through our existing sales force, benefiting from efficiencies of scale, adding to the capacity of existing plants, and making our business processes more efficient.

We expect BGE and our other retail energy service businesses to grow through focused and disciplined expansion primarily from new customers. At BGE, we are also focused on enhancing reliability and customer satisfaction.

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

We are constantly reevaluating our strategies and might consider:

- acquiring or developing additional generating facilities and gas properties to support our merchant energy business,
- mergers or acquisitions of utility or non-utility businesses or assets, and
- sale of assets or one or more businesses.

Business Environment

With the evolving regulatory environment surrounding customer choice, increasing competition, and the growth of our merchant energy business, various factors affect our financial results. We discuss some of these factors in more detail in the *Item 1. Business Competition* section. We also discuss these various factors in the *Forward Looking Statements* and *Item 1A. Risk Factors* sections.

Over the last several years, the energy markets have been highly volatile with significant changes in natural gas, power, oil, coal, and emission allowance prices. The volatility of the energy markets impacts our credit portfolio, and we continue to actively manage our credit portfolio to attempt to reduce the impact of a potential counterparty default. We discuss our customer (counterparty) credit and other risks in more detail in the *Market Risk* section.

In addition, the volatility of the energy markets impacts our liquidity and collateral requirements. We discuss our liquidity in the *Financial Condition* section.

Competition

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

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

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

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

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

Regulation by the Maryland PSC

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

Base Rates

Base rates are the rates the Maryland PSC allows BGE to charge its customers for the cost of providing them delivery service, plus a profit. BGE has both electric base rates and gas base rates. Higher electric base rates apply during the summer when the demand for electricity is higher. Gas base rates are not affected by seasonal changes.

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

As a result of the deregulation of electric generation in Maryland, BGE's residential electric base rates are frozen until July 2006. Electric base rates were frozen until July 2004 for commercial and industrial customers. In early 2006, the Maryland PSC commenced a proceeding, and legislation was introduced in the Maryland General Assembly, to consider methods for requiring BGE to defer recovery of some of its costs of providing residential POLR service. These actions are a result of the anticipated increase in POLR prices expected to take place upon the expiration of the residential rate freeze in June 2006. Any decision by the Maryland PSC or legislation adopted by the Maryland General Assembly, that would defer recovery of, or would not allow BGE to fully recover its costs could have a material impact on our, and BGE's, financial results and liquidity. We discuss electric deregulation in *Item 1. Business Electric Regulatory Matters and Competition* section.

In April 2005, BGE filed an application for a $52.7 million annual increase in its gas base rates. The Maryland PSC issued an order in December 2005 granting BGE an annual increase of $35.6 million. Certain parties to the proceeding have sought judicial review and Maryland PSC rehearing of the decision. BGE will not seek review of any aspect of the order. We cannot provide assurance that a court will not reverse any aspect of the order or that it will not remand certain issues to the Maryland PSC.

Electric Commodity and Transmission Charges

BGE electric commodity and transmission charges (standard offer service) are discussed in *Item 1. Business Electric Regulatory Matters and Competition* section.

Gas Commodity Charge

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

Federal Regulation

FERC

The FERC has jurisdiction over various aspects of our business, including transmission and wholesale electricity sales. We believe that FERC's continued commitment to competition in wholesale energy markets should result in improved competitive markets across various regions.

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

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

Recent initiatives at FERC have included a review of its methodology for the granting of market-based rate authority to sellers of electricity. FERC has announced new interim tests that will be used to determine the extent to which companies may have market power in certain regions. Where market power is found to exist, FERC may require companies to implement measures to mitigate the market power in order to maintain market-based rate authority. In addition, FERC is reviewing other aspects of its granting of market-based rate authority, including transmission market power, affiliate abuse, and barriers to entry. We cannot determine the eventual outcome of FERC's efforts in this regard and their impact on our financial results at this time.

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

In addition, FERC has indicated that it will provide transmission customers that are charged the SECA rates with an opportunity to demonstrate that such charges should be shifted to their wholesale power suppliers. We are a recipient of SECA payments, payer of SECA charges, and supplier to whom such charges may be shifted. We are unable to predict the timing or outcome of FERC's SECA rate proceeding. However, as the amounts collected under the SECA rates are subject to refund and the ultimate outcome of the proceeding establishing SECA rates is uncertain, the result of this proceeding may have a material effect on our financial results.

In May 2005, FERC issued an order accepting BGE's joint application to have network transmission rates established through a formula that tracks costs instead of through fixed rates. The formula approach became effective June 1, 2005, and the implementation of these rates did not have a material effect on our, or BGE's, financial results. The use of this formula approach is subject to refund based on the outcome of a hearing before an administrative law judge. The hearing process has been suspended while the various parties discuss a possible settlement. We cannot predict the outcome of this proceeding or whether FERC will ultimately affirm either a settlement or the judge's decision.

Other market changes are also being considered, including potential revisions to PJM's capacity market and rate design. Such changes will be subject to FERC's review and approval. We cannot predict the outcome of these proceedings or the possible effect on our, or BGE's, financial results at this time.

Federal Energy Legislation

The Energy Policy Act of 2005 (EPACT 2005) was signed by the President on August 8, 2005. The legislation encourages investments in energy production and delivery infrastructure, including further development of competitive wholesale energy markets, and promotes the use of a diverse mix of fuels and renewable technologies to generate electricity, including federal support and tax incentives for clean coal, nuclear, and renewable power generation. Effective February 2006, the legislation repealed the Public Utility Holding Company Act of 1935 (PUHCA 1935).

In addition, there are a number of FERC rulemaking proceedings that relate to the implementation of EPACT 2005 including proceedings relating to FERC's new responsibilities following the repeal of PUHCA 1935, its revised merger authority, its new authority over electric grid reliability, and its new authority with respect to addressing electric and gas market manipulation. While FERC has moved expeditiously to implement its new authority under EPACT 2005, at this time we are unable to predict the ultimate impact of these rules or the possible effect on our business or financial results given that these rules may be subject to further revision or clarification as a result of requests for rehearing or court appeals but they could have a material impact on our financial results.

There are also rulemakings required from other federal agencies, the outcome of which could affect our financial results, but we cannot at this time predict such outcome or the actual effect on our financial results.

Weather

Merchant Energy Business

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

BGE

Weather affects the demand for electricity and gas for our regulated businesses. Very hot summers and very cold winters increase demand. Mild weather reduces demand. Weather affects residential sales more than commercial and industrial sales, which are mostly affected by business needs for electricity and gas. The Maryland PSC allows BGE to record a monthly adjustment to our regulated gas business revenues to eliminate the effect of abnormal weather patterns. We discuss this further in the *Regulated Gas Business Weather Normalization* section.

Other Factors

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

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

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

- weather conditions,

market liquidity,

capability and reliability of the physical electricity and gas systems,

local transportation systems, and

the nature and extent of electricity deregulation.

Our merchant energy business contracts for the delivery of coal to our coal-fired generation facilities. 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. In the second, third, and fourth quarters of 2004, we experienced delays in deliveries from one of the rail companies that supplies coal to our generating facilities. In response, we procured coal using an alternative delivery method to meet our contractual load obligations. We discuss the impact of these delays on our financial results in the *Mid-Atlantic Region* section. The majority of the coal that was not delivered during 2004 was delivered during 2005.

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

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

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

Environmental Matters and Legal Proceedings

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

Accounting Standards Adopted and Issued

We discuss recently adopted and issued accounting standards in *Note 1*.

Critical Accounting Policies

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

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

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

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

Accounting for Derivatives

Our merchant energy business originates and acquires contracts for energy, other energy-related commodities, and related derivatives. We record merchant energy business revenues using two methods of accounting: accrual accounting and mark-to-market accounting. The accounting requirements for derivatives are governed by Statement of Financial Accounting Standard (SFAS) No. 133, *Accounting for Derivative Instruments and Hedging Activities,* as amended, and applying those requirements involves the exercise of judgment in evaluating these provisions, as well as related implementation guidance and applying those requirements to complex contracts in a variety of commodities and markets.

We record revenues and fuel and purchased energy expenses from the sale or purchase of energy, energy-related products, and energy services under the accrual method of accounting in the period when we deliver or receive energy commodities, products, and services, or settle contracts. We use accrual accounting for our merchant energy and other nonregulated business transactions, including the generation or purchase and sale of electricity, gas, and coal as part of our physical delivery activities and for power, gas, and coal sales contracts that are not subject to mark-to-market accounting. Contracts that are eligible for accrual accounting include non-derivative transactions and derivatives that qualify for and are designated as normal purchases and normal sales of commodities that will be physically delivered.

The use of accrual accounting requires us to analyze contracts to determine whether they are non-derivatives or, if they are derivatives, whether they meet the requirements for designation as normal purchases and normal sales. For those contracts that do not meet these criteria, we may also analyze whether they qualify for hedge accounting, including performing an evaluation of historical market price information to determine whether such contracts are expected to be highly effective in offsetting changes in cash flows from the risk being hedged. We record the fair value of derivatives for which we have elected hedge accounting in "Risk management assets and liabilities."

We use the mark-to-market method of accounting for derivative contracts for which we are not permitted to use accrual accounting or hedge accounting. These mark-to-market activities include derivative contracts for energy and other energy-related commodities. Under the mark-to-market method of accounting, we record the fair value of these derivatives as mark-to-market energy assets and liabilities at the time of contract execution. We record the changes in mark-to-market energy assets and liabilities in our Consolidated Statements of Income.

Mark-to-market energy assets and liabilities consist of a combination of energy and energy-related derivative contracts. While some of these contracts represent commodities or instruments for which prices are available from external sources, other commodities and certain contracts are not actively traded and are valued using modeling techniques to determine expected future market prices, contract quantities, or both. The market prices and quantities used to determine fair value reflect management's best estimate considering various factors. However, future market prices and actual quantities will vary from those used in recording mark-to-market energy assets and liabilities, and it is possible that such variations could be material.

We record valuation adjustments to reflect uncertainties associated with certain estimates inherent in the determination of the fair value of mark-to-market energy assets and liabilities. The effect of these uncertainties is not incorporated in market price information or other market-based estimates used to determine fair value of our mark-to-market energy contracts. To the extent possible, we utilize market-based data together with quantitative methods for both measuring the uncertainties for which we record valuation adjustments and determining the level of such adjustments and changes in those levels.

We describe on the next page the main types of valuation adjustments we record and the process for establishing each. Generally, increases in valuation adjustments reduce our earnings, and decreases in valuation adjustments increase our earnings. However, all or a portion of the effect on earnings of changes in valuation adjustments may be offset by changes in the value of the underlying positions.

Close-out adjustment represents the estimated cost to close out or sell to a third-party open mark-to-market positions. This valuation adjustment has the effect of valuing "long" positions (the purchase of a commodity) at the bid price and "short" positions (the sale of a commodity) at the offer price. We compute this adjustment using a market-based estimate of the bid/offer spread for each commodity and option price and the absolute quantity of our net open positions for each year. The level of total close-out valuation adjustments increases as we have larger unhedged positions, bid-offer spreads increase, or market information is not available, and it decreases as we reduce our unhedged positions, bid-offer spreads decrease, or market information becomes available. To the extent that we are not able to obtain observable market information for similar contracts, the close-out adjustment is equivalent to the initial contract margin, thereby resulting in no gain or loss at inception. In the absence of observable market information, there is a presumption that the transaction price is equal to the market value of the contract, and therefore we do not recognize a gain or loss at inception. We recognize such gains or losses in earnings as we realize cash flows under the contract or when observable market data becomes available.

Credit-spread adjustment for risk management purposes, we compute the value of our mark-to-market energy assets and liabilities using a risk-free discount rate. In order to compute fair value for financial reporting purposes, we adjust the value of our mark-to-market energy assets to reflect the credit-worthiness of each counterparty based upon either published credit ratings, or equivalent internal credit ratings and associated default probability percentages. We compute this adjustment by applying a default probability percentage to our outstanding credit exposure, net of collateral, for each counterparty. The level of this adjustment increases as our credit exposure to counterparties increases, the maturity terms of our transactions increase, or the credit ratings of our counterparties deteriorate, and it decreases when our credit exposure to counterparties decreases, the maturity terms of our transactions decrease, or the credit ratings of our counterparties improve.

Market prices for energy and energy-related commodities vary based upon a number of factors, and changes in market prices affect both the recorded fair value of our mark-to-market energy contracts and the level of future revenues and costs associated with accrual-basis activities. Changes in the value of our mark-to-market energy contracts will affect our earnings in the period of the change, while changes in forward market prices related to accrual-basis revenues and costs will affect our earnings in future periods to the extent those prices are realized. We cannot predict whether, or to what extent, the factors affecting market prices may change, but those changes could be material and could affect us either favorably or unfavorably. We discuss our market risk in more detail in the *Market Risk* section.

The impact of derivative contracts on our revenues and costs is affected by many factors, including:

- our ability to designate and qualify derivative contracts for normal purchase and sale accounting or hedge accounting under SFAS No. 133,
- potential volatility in earnings from ineffectiveness associated with derivatives subject to hedge accounting,
- potential volatility in earnings from derivative contracts that serve as economic hedges but do not meet the accounting requirements to qualify for normal purchase and normal sale accounting or hedge accounting,
- our ability to enter into new mark-to-market derivative origination transactions, and
- sufficient liquidity and transparency in the energy markets to permit us to record gains at inception of new derivative contracts because fair value is evidenced by quoted market prices, current market transactions, or other observable market information.

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

Long-Lived Assets

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

- a significant decrease in the market price of a long-lived asset,
- a significant adverse change in the manner an asset is being used or its physical condition,

- an adverse action by a regulator or legislation or in the business climate,
- an accumulation of costs significantly in excess of the amount originally expected for the construction or acquisition of an asset,
- a current-period loss combined with a history of losses or the projection of future losses, or
- a change in our intent about an asset from an intent to hold to a greater than 50% likelihood that an asset will be sold or disposed of before the end of its previously estimated useful life.

For long-lived assets that are expected to be held and used, SFAS No. 144 provides that an impairment loss shall only be recognized if the carrying amount of an asset is not recoverable and exceeds its fair value. The carrying amount of an asset is not recoverable under SFAS No. 144 if the carrying amount exceeds the sum of the undiscounted future cash flows expected to result from the use and eventual disposition of the asset. Therefore, when we believe an impairment condition may have occurred, we are required to estimate the undiscounted future cash flows associated with a long-lived asset or group of long-lived assets. This necessarily requires us to estimate uncertain future cash flows.

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

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

For long-lived assets that can be classified as assets held for sale under SFAS No. 144, an impairment loss is recognized to the extent their carrying amount exceeds their fair value less costs to sell.

If we determine that the undiscounted cash flows from an asset to be held and used are less than the carrying amount of the asset, or if we have classified an asset as held for sale, we must estimate fair value to determine the amount of any impairment loss. The estimation of fair value under SFAS No. 144, whether in conjunction with an asset to be held and used or with an asset held for sale, also involves judgment. We consider quoted market prices in active markets to the extent they are available. In the absence of such information, we may consider prices of similar assets, consult with brokers, or employ other valuation techniques. Often, we will discount the estimated future cash flows associated with the asset using a single interest rate that is commensurate with the risk involved with such an investment or employ an expected present value method that probability-weights a range of possible outcomes. The use of these methods involves the same inherent uncertainty of future cash flows as discussed above with respect to undiscounted cash flows. Actual future market prices and project costs could vary from those used in our estimates, and the impact of such variations could be material.

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

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

Gas Properties

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

Debt and Equity Securities

Our investments in debt and equity securities, primarily our nuclear decommissioning trust fund assets, are subject to impairment evaluations under FASB Staff Position SFAS 115-1 and SFAS 124-1 (FSP 115-1 and 124-1), *The Meaning of Other-Than-Temporary Impairment and Its Application to Certain Investments.* FSP 115-1 and 124-1 requires us to determine whether a decline in fair value of an investment below the amortized cost basis is other than temporary. If we determine that the decline in fair value is judged to be other than temporary, the cost basis of the investment must be written down to fair value as a new cost basis.

Goodwill

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

Asset Retirement Obligations

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

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

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

Significant Events

Pending Merger with FPL Group, Inc.

On December 18, 2005, Constellation Energy entered into an Agreement and Plan of Merger with FPL Group, Inc. We discuss the details of this pending merger in *Note 15.*

Prior to the merger, which is subject to shareholder and various regulatory approvals, Constellation Energy and FPL Group will continue to operate as separate companies. The discussion and analysis of our results of operations and financial condition beginning on the next page relates solely to Constellation Energy.

Commodity Prices

During 2005, the energy markets were affected by higher commodity prices caused by a tight supply and demand balance, the impact of hot weather, and hurricane-related supply disruptions in the Gulf Coast. These events contributed to the following changes in our financial statements:

- total mark-to-market assets increased $1,501.4 million and total mark-to-market liabilities increased $1,386.3 million since December 31, 2004,
- total risk management assets increased $1,092.6 million and total risk management liabilities increased $742.5 million since December 31, 2004,
- customer deposits and collateral increased $235.1 million since December 31, 2004,
- accumulated other comprehensive income decreased $314.0 million since December 31, 2004,
- total revenues increased $4,845.6 million during 2005 compared to 2004, and
- total fuel and purchased energy expenses increased $4,546.8 million during 2005 compared to the same period of 2004.

We discuss the impact of higher commodity prices on our financial condition and results of operations in more detail in the following sections:

- *Merchant Energy Results*,

Financial Condition,

Contractual Payment Obligations and Committed Amounts, and

Market Risk.

Discontinued Operations

In June 2005, we sold our Oleander generating facility and in October 2005, we sold Constellation Power International Investments, Ltd., which held our other nonregulated international investments. Our other nonregulated international investments included our interests in a Panamanian electric distribution facility and a fund that holds interests in two South American energy projects.

We discuss the sale of the Oleander generating facility and our other nonregulated international investments in more detail in the *Note 2*.

Business Combination and Asset Acquisition

In April 2005, we acquired Cogenex Corporation and in June 2005, we acquired working interests in gas producing fields in Texas and Alabama.

We discuss these transactions in more detail in *Note 15*.

Dividend Increase

In January 2006, we announced an increase in our quarterly dividend to $0.3775 per share on our common stock. This is equivalent to an annual rate of $1.51 per share. Previously, our quarterly dividend on our common stock was $0.335 per share, equivalent to an annual rate of $1.34 per share.

Results of Operations

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

Overview

Results

	2005	2004	2003
		(In millions, after-tax)	
Merchant energy	**$ 430.2**	$ 426.4	$ 301.1
Regulated electric	**149.4**	131.1	107.5
Regulated gas	**26.7**	22.2	43.0
Other nonregulated	**0.4**	(12.9)	5.1
Income from continuing operations and before cumulative effects of changes in accounting principles	**606.7**	566.8	456.7
Income (loss) from discontinued operations	**23.6**	(27.1)	19.0
Cumulative effects of changes in accounting principles	**(7.2)**		(198.4)
Net Income	**$ 623.1**	$ 539.7	$ 277.3
Other Items Included in Operations:			
Non-qualifying hedges	**$ (24.9)**	$ 0.2	$ (28.7)
Merger-related transaction costs	**(15.6)**		
Workforce reduction costs	**(2.6)**	(5.9)	(1.3)
Recognition of 2003 synthetic fuel tax credits		35.9	
Total Other Items	**$ (43.1)**	$ 30.2	$ (30.0)

2005

Our total net income for 2005 increased $83.4 million, or $0.35 per share, compared to the same period of 2004 mostly because of the following:

We had higher earnings of approximately $58 million at our wholesale marketing and risk management operation. This increase is primarily due to the realization of higher gross margin, which included the termination or restructuring of several energy contracts and higher mark-to-market results in earnings. We discuss these terminations, restructurings, and mark-to-market results in more detail in the *Competitive Supply* section. This increase in earnings was partially offset by higher load-serving costs resulting from extreme weather and volatile commodity prices and higher operating expenses.

We recorded higher income from discontinued operations of $50.7 million after-tax. In 2005, we recorded in "Income (loss) from discontinued operations" earnings of $23.6 million related to the sale of our Oleander generating facility and our other nonregulated international investments. In 2004, we recorded in "Income (loss) from discontinued operations" a loss of $49.1 million after tax related to the sale of our Hawaiian geothermal facility which had a negative impact in that period. The loss was offset by the reclassification of earnings of $22.0 million after-tax from our Oleander and international operations to "Income (loss) from discontinued operations." We discuss the sale of these operations in more detail in *Note 2.*

We had higher earnings of $32.7 million after-tax primarily due to higher interest and investment income due to a higher cash balance, and higher decommissioning trust asset earnings, and lower interest expense resulting from the maturity of $300.0 million in long-term debt in 2005 and the favorable impact of floating-rate swaps.

We had higher earnings of $29.1 million after-tax at our Nine Mile Point and Ginna facilities primarily due to productivity improvements and cost saving initiatives partially offset by inflationary cost increases and costs associated with the planned refueling outage at Ginna.

We had higher earnings of $22.8 million after-tax at our regulated businesses primarily due to favorable weather during 2005 compared to 2004.

We had higher earnings of approximately $17 million after-tax due to the absence of coal delivery issues that were experienced in 2004 that had a negative impact in that period. We discuss the coal delivery issues in more detail in the *Business Environment Other Factors* section.

We had higher earnings from our other nonregulated businesses of $13.3 million after-tax, including higher gains from the continued liquidation of our non-core investments and the results of Cogenex, which was acquired in April 2005. We discuss the acquisition of Cogenex in more detail in *Note 15*.

We had higher earnings at our South Carolina synthetic fuel facility of $7.6 million after-tax due to a higher level of production in 2005 compared to 2004.

These increases were partially offset by the following:

Our merchant energy business recognized $35.9 million of 2003 synthetic fuel tax credits in 2004 which had a positive impact in that period.

We had lower earnings at our retail competitive supply operation of $25.1 million after-tax primarily due to higher costs to serve our load obligations in Texas and the absence of bankruptcy settlements that had a favorable impact in 2004.

We had lower earnings of $25.1 million after-tax related to losses associated with certain economic hedges that do not qualify for cash-flow hedge accounting treatment. We discuss these economic hedges in more detail in the *Mark-to-Market* section.

We had lower earnings of $15.6 million after-tax due to external costs associated with the execution of our merger agreement with FPL Group.

We had lower earnings of $20.0 million after-tax due to lower CTC revenues at our merchant energy business.

We had lower earnings of $8.5 million after-tax related to the impact of expensing stock options during the fourth quarter of 2005.

We had lower earnings of $7.2 million after-tax due to the cumulative effect of adopting FIN 47 and SFAS No. 123 Revised (SFAS No. 123R), *Share-Based Payment*. We discuss the adoption of these standards in detail in *Note 1*.

Earnings per share was impacted by additional dilution, including the issuance of 6.0 million shares of common stock on July 1, 2004.

2004

Our total net income for 2004 increased $262.4 million, or $1.46 per share, compared to the same period of 2003 mostly because of the following:

In 2003, we recorded a $266.1 million after-tax loss for the cumulative effect of adopting Emerging Issues Task Force (EITF) Issue 02-3, *Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities*. This was partially offset by a $67.7 million after-tax gain for the cumulative effect of adopting SFAS No. 143. These items had a combined negative impact during 2003.

Our merchant energy business had higher earnings of $78.4 million at our South Carolina synthetic fuel facility primarily due to the recognition of $35.9 million in tax credits associated with 2003 production and tax credits associated with 2004 production.

We had higher earnings from our regulated electric business mostly because of the absence of $19.4 million of after-tax incremental operations and maintenance expenses due to distribution service restoration efforts associated with Hurricane Isabel in 2003.

We had higher earnings from our nuclear generating assets due to the June 2004 acquisition of Ginna, which contributed $28.1 million after-tax, and higher generation at our Calvert Cliffs nuclear power plant, partially offset by lower generation by and lower power prices for the output of our Nine Mile Point facility in 2004 compared to 2003.

We had higher earnings from our merchant energy business mostly due to the realization of wholesale contracts originated in prior periods, portfolio management, and favorable settlements at our retail electric operation of $16.9 million pre-tax.

We had higher earnings due to lower after-tax losses of $28.9 million associated with certain economic hedges that do not qualify for cash-flow hedge accounting treatment. We discuss these economic hedges in more detail in the *Mark-to-Market* section.

We had higher earnings of $20.9 million after-tax in 2004 due to a full year of operations at the High Desert facility.

These increases were partially offset by the following:

We recorded a $49.1 million after-tax, loss from discontinued operations on the sale of our Hawaiian geothermal facility.

We had higher Sarbanes-Oxley 404 implementation costs of approximately $15 million pre-tax, higher enterprise information systems expenditures of approximately $8 million pre-tax, and higher compensation, benefit, and other inflationary cost increases.

We had lower earnings from our regulated gas business mostly because of $13.6 million after-tax of higher operations and maintenance expenses in 2004 and the absence of a $4.7 million after-tax market-based rate gas recovery, which had a favorable effect in 2003.

We recognized a gain of $16.4 million after-tax related to non-core asset sales in 2003 that had a favorable impact in that period.

Earnings per share was impacted by additional dilution resulting from the issuance of 6.0 million shares of common stock on July 1, 2004.

Merchant Energy Business

Background

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

Our merchant energy business focuses on delivery of physical, customer-oriented products to producers and consumers, manages the risk and optimizes the value of our owned generation assets, and uses our portfolio management and trading capabilities both to manage risk and to deploy risk capital to generate additional returns.

We record merchant energy revenues and expenses in our financial results in different periods depending upon which portion of our business they affect. We discuss our revenue recognition policies in the *Critical Accounting Policies* section and in *Note 1*. We summarize our revenue and expense recognition policies as follows:

We record revenues as they are earned and fuel and purchased energy expenses as they are incurred for contracts and activities subject to accrual accounting, including certain load-serving activities.

Prior to the settlement of the forecasted transaction being hedged, we record changes in the fair value of contracts designated as cash-flow hedges in other comprehensive income to the extent that the hedges are effective. We record the effective portion of the changes in fair value of hedges in earnings in the period the settlement of the hedged transaction occurs. We record the ineffective portion of the changes in fair value of hedges, if any, in earnings in the period in which the change occurs.

We record changes in the fair value of contracts that are subject to mark-to-market accounting in revenues or fuel and purchased energy expenses in the period in which the change occurs.

Mark-to-market accounting requires us to make estimates and assumptions using judgment in determining the fair value of certain contracts and in recording revenues from those contracts. We discuss the effects of mark-to-market accounting on our results in the *Competitive Supply Mark-to-Market* section. We discuss mark-to-market accounting and the accounting policies for the merchant energy business further in the *Critical Accounting Policies* section and in *Note 1*.

Our wholesale marketing and risk management operation actively uses energy and energy-related commodities in order to manage our portfolio of energy purchases and sales to customers through structured transactions. As part of our risk management activities we trade energy and energy-related commodities and deploy risk capital in the management of our portfolio in order to earn additional returns. These activities are managed through daily value at risk and stop loss limits and liquidity guidelines, and may have a material impact on our financial results. We discuss the impact of our trading activities and value at risk in more detail in the *Competitive Supply Mark-to-Market* and *Market Risk* sections.

Results

	2005	2004	2003
		(In millions)	
Revenues	**$ 14,786.1**	$ 10,347.5	$ 7,587.5
Fuel and purchased energy expenses	**(12,308.9)**	(8,124.8)	(5,702.2)
Operating expenses	**(1,364.3)**	(1,172.8)	(932.8)
Merger-related transaction costs	**(11.2)**		
Workforce reduction costs	**(4.4)**	(9.7)	(1.2)
Depreciation, depletion, and amortization	**(269.6)**	(239.2)	(214.6)
Accretion of asset retirement obligations	**(62.1)**	(53.2)	(42.7)
Taxes other than income taxes	**(112.2)**	(88.5)	(85.9)
Income from Operations	**$ 653.4**	$ 659.3	$ 608.1
Income from continuing operations and before cumulative effects of changes in accounting principles (after-tax)	**$ 430.2**	$ 426.4	$ 301.1
Income (loss) from discontinued operations (after-tax)	**3.0**	(36.5)	11.9
Cumulative effects of changes in accounting principles (after-tax)	**(7.4)**		(198.4)
Net Income	**$ 425.8**	$ 389.9	$ 114.6
Other Items Included in Operations (after-tax)			
Non-qualifying hedges	**$ (24.9)**	$ 0.2	$ (28.7)
Merger-related transaction costs	**(10.4)**		
Workforce reduction costs	**(2.6)**	(5.9)	(0.7)
Recognition of 2003 synthetic fuel tax credits		35.9	
Total Other Items	**$ (37.9)**	$ 30.2	$ (29.4)

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

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

Revenues and Fuel and Purchased Energy Expenses

Our merchant energy business manages the revenues we realize from the sale of energy to our customers and our costs of procuring fuel and energy. The difference between revenues and fuel and purchased energy expenses is the gross margin of our merchant energy business, and this measure is a useful tool for assessing the profitability of our merchant energy business. Accordingly, we believe it is appropriate to discuss the operating results of our merchant energy business by analyzing the changes in gross margin between periods. In managing our portfolio, we may terminate, restructure, or acquire contracts. Such transactions are within the normal course of managing our portfolio and may materially impact the timing of our recognition of revenues, fuel and purchased energy expenses, and cash flows.

We analyze our merchant energy gross margin in the following categories because of the risk profile of each category, differences in the revenue sources, and the nature of fuel and purchased energy expenses. With the exception of a portion of our competitive supply activities that we are required to account for using the mark-to-market method of accounting, all of these activities are accounted for on an accrual basis.

Mid-Atlantic Region our fossil, nuclear, and hydroelectric generating facilities and load-serving activities in the PJM Interconnection (PJM) region. This also includes active portfolio management of the generating assets and other physical and financial contractual arrangements, as well as other PJM competitive supply activities.

Plants with Power Purchase Agreements our generating facilities outside the Mid-Atlantic Region with long-term power purchase agreements, including the Nine Mile Point, Ginna, University Park, and High Desert generating facilities.

Wholesale Competitive Supply our marketing and risk management operation that provides energy products and services (including portfolio management and trading activities) outside the Mid-Atlantic Region primarily to distribution utilities, power generators, and other wholesale customers. We also provide global coal and upstream and downstream natural gas services.

Retail Competitive Supply our operation that provides electric and gas energy products and services to commercial, industrial and governmental customers.

Other our investments in qualifying facilities and domestic power projects and our generation operations and maintenance services.

We provide a summary of our revenues, fuel and purchased energy expenses, and gross margin as follows:

		2005			2004			2003	
					(Dollar amounts in millions)				
Revenues:									
Mid-Atlantic Region	$	**2,283.9**		$	1,925.6		$	1,696.2	
Plants with Power Purchase Agreements		**829.6**			714.5			574.6	
Competitive Supply									
Retail		**6,942.3**			4,280.0			2,567.7	
Wholesale		**4,672.3**			3,353.8			2,703.9	
Other		**58.0**			73.6			45.1	
Total	$	**14,786.1**		$	10,347.5		$	7,587.5	
Fuel and purchased energy expenses:									
Mid-Atlantic Region	$	**(1,436.5)**		$	(946.9)		$	(711.6)	
Plants with Power Purchase Agreements		**(79.6)**			(53.1)			(48.0)	
Competitive Supply									
Retail		**(6,668.2)**			(4,011.4)			(2,389.5)	
Wholesale		**(4,124.6)**			(3,113.4)			(2,553.1)	
Other									
Total	$	**(12,308.9)**		$	(8,124.8)		$	(5,702.2)	
Gross margin:			**% of Total**			**% of Total**			**% of Total**
Mid-Atlantic Region	$	**847.4**	**34%**	$	978.7	44%	$	984.6	52%
Plants with Power Purchase Agreements		**750.0**	**30**		661.4	30		526.6	28
Competitive Supply									
Retail		**274.1**	**11**		268.6	12		178.2	9
Wholesale		**547.7**	**22**		240.4	11		150.8	8
Other		**58.0**	**3**		73.6	3		45.1	3

		2005			2004			2003	
Total	**$**	**2,477.2**	**100%**	$	2,222.7	100%	$	1,885.3	100%

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

<u>*Mid-Atlantic Region*</u>

		2005		2004		2003
				(In millions)		
Revenues	**$**	**2,283.9**	$	1,925.6	$	1,696.2
Fuel and purchased energy expenses		**(1,436.5)**		(946.9)		(711.6)
Gross margin	**$**	**847.4**	$	978.7	$	984.6

The decrease in Mid-Atlantic Region gross margin in 2005 compared to 2004 is primarily due to rising commodity prices and hotter than normal weather during the third quarter of 2005, which resulted in higher load-serving costs. In addition, CTC revenues were $33.1 million lower during 2005 compared to the same period of 2004. These decreases in gross margin were partially offset by the absence of coal delivery issues that we experienced in 2004 that had a negative impact in that period. We discuss the coal delivery issues in the *Business Environment Other Factors* section.

CTC revenues will continue to decrease as residential, commercial, and industrial customers complete their CTC obligation. CTC revenues will be completely phased-out for residential customers by June 30, 2006 and CTC revenues for commercial and industrial customers will begin to be phased-out after June 30, 2006. We discuss the change in CTC revenue over time in more detail in *Item 1. Business*.

The slight decrease in Mid-Atlantic Region gross margin in 2004 compared to 2003 is primarily due to lower fossil plant availability resulting in lower gross margin of $17.0 million and higher coal costs primarily due to purchasing coal from alternative suppliers in 2004 at higher prices than in 2003 as a result of delays in deliveries. These decreases were partially offset by an increase in margin of $7.1 million related to new load-serving obligations, offset in part by lower volumes served to BGE resulting from small commercial customers leaving BGE's standard offer service due to the end of fixed-price service in June 2004.

Plants with Power Purchase Agreements

	2005	2004	2003
		(In millions)	
Revenues	**$ 829.6**	$ 714.5	$ 574.6
Fuel and purchased energy expenses	**(79.6)**	(53.1)	(48.0)
Gross margin	**$ 750.0**	$ 661.4	$ 526.6

The increase in gross margin from our Plants with Power Purchase Agreements in 2005 compared to 2004 was primarily due to:

- higher gross margin of $71.5 million from Ginna, which was acquired in June 2004. This increase in gross margin at Ginna includes an increase in revenues of $76.9 million. We discuss this acquisition in more detail in *Note 15,* and
- higher gross margin of $39.0 million at our Nine Mile Point facility that benefited from higher generation primarily due to fewer refueling outage days, the absence of an unplanned outage that occurred in January 2004, and higher prices on the portion of our output sold into the wholesale market.

These increases in gross margin were partially offset by $21.9 million primarily related to changes in commodity prices that had a negative impact on realized hedging activities related to the portion of these facilities sold into the wholesale market.

The increase in gross margin from our Plants with Power Purchase Agreements in 2004 compared to 2003 is primarily due to:

- gross margin of $112.4 million from Ginna. The increase in gross margin includes higher revenues of $119.1 million, and
- higher gross margin of $45.9 million from the High Desert facility that contributed a full year of gross margin in 2004 compared to eight months in 2003.

These increases in gross margin were partially offset by lower gross margin of $21.0 million at our Nine Mile Point facility primarily due to lower revenues from reduced contract prices for the output in 2004 compared to 2003 and lower generation.

Competitive Supply

Retail

	2005	2004	2003
		(In millions)	
Accrual revenues	**$ 6,944.2**	$ 4,281.0	$ 2,567.7
Mark-to-market results recorded in earnings	**18.3**	(1.0)	
Fuel and purchased energy expenses	**(6,688.4)**	(4,011.4)	(2,389.5)
Gross margin	**$ 274.1**	$ 268.6	$ 178.2

The slight increase in gross margin from our retail competitive supply activities in 2005 compared to 2004 is primarily due to serving approximately 20 million more megawatt hours in 2005 compared to 2004 mostly due to the growth of this operation and the positive impact of certain contracts that were recorded as mark-to-market. These increases were substantially offset by:

a combination of higher market prices for electricity, price volatility, and increased customer usage primarily in Texas, which increased our cost to serve our load-serving obligations.

the expiration of higher margin contracts, and

the absence of favorable bankruptcy settlements, which had a positive impact in 2004. We discuss the favorable bankruptcy settlements below.

The increase in gross margin from our retail competitive supply activities in 2004 compared to 2003 is primarily due to higher electric gross margin of $66.1 million mostly due to:

serving approximately 16 million more megawatt hours partially offset by lower realized margins due to increased wholesale power costs in 2004 compared to 2003,

a bankruptcy settlement from PG&E of $10.3 million in 2004, and a favorable settlement of a pre-acquisition liability of $6.6 million also related to a bankruptcy proceeding in 2004, and

lower contract amortization, which reduced margin by $9.2 million, relating to the fair value of contracts acquired.

In addition, we had higher gas gross margin contribution of $17.1 million from Blackhawk Energy Services and Kaztex Energy Management, which were acquired in October 2003. We discuss our acquisitions in more detail in *Note 15.*

Wholesale

	2005	**2004**	**2003**
		(In millions)	
Accrual revenues	**$ 4,281.8**	$ 3,253.7	$ 2,667.7
Fuel and purchased energy expenses	**(4,124.6)**	(3,113.4)	(2,553.1)
Wholesale accrual activities	**157.2**	140.3	114.6
Mark-to-market results recorded in earnings	**390.5**	100.1	36.2
Gross margin	**$ 547.7**	$ 240.4	$ 150.8

We analyze our wholesale accrual and mark-to-market competitive supply activities separately on the next page.

Wholesale Accrual Activities

Our wholesale marketing and risk management operation's accrual gross margin was $16.9 million higher in 2005 compared to 2004 primarily due to newly originated and realized business in power, gas, and coal in 2005, including several contract terminations and restructurings. During 2005, we terminated or restructured several in-the-money contracts in exchange for upfront cash payments and a reduction or cancellation of future performance obligations. The termination or restructuring of two contracts allowed us to lower our exposure to performance risk under these contracts, and resulted in the realization of $77.0 million of pre-tax earnings in 2005 that would have been recognized over the life of these contracts. These increases were partially offset by lower gross margins of approximately $60 million mostly due to the absence of several favorable items, including settlements, power prices, and contracts that had a positive impact in 2004.

The increase in gross margin from our wholesale accrual activities in 2004 compared to 2003 is primarily due to approximately $50 million in the New England region due to higher realized contract margins in 2004 compared to 2003 and higher volumes served. This increase was partially offset by higher transportation costs for our gas trading portfolio of approximately $16 million. The transportation costs associated with this portfolio are accounted for on an accrual basis, while our gas trading portfolio is recorded as mark-to-market. In addition, we incurred higher operating costs of $5.0 million related to our South Carolina synthetic fuel facility.

Mark-to-Market

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

As a result of the nature of our operations and the use of mark-to-market accounting for certain activities, mark-to-market earnings will fluctuate. We cannot predict these fluctuations, but the impact on our earnings could be material. We discuss our market risk in more detail in the *Market Risk* section. The primary factors that cause fluctuations in our mark-to-market results recorded in earnings are:

- the number, size, and profitability of new transactions including terminations or restructuring of existing contracts,
- the number and size of our open derivative positions, and
- changes in the level and volatility of forward commodity prices and interest rates.

Mark-to-market results recorded in earnings were as follows:

	2005	2004	2003
		(In millions)	
Unrealized mark-to-market results recorded in earnings			
Origination gains	**$ 61.6**	$ 19.7	$ 62.3
Risk management and trading			
Unrealized changes in fair value	**347.2**	79.4	(26.1)
Changes in valuation techniques			
Reclassification of settled contracts to realized	**(257.7)**	(85.4)	(123.5)
Total risk management and trading	**89.5**	(6.0)	(149.6)
Total unrealized mark-to-market*	**151.1**	13.7	(87.3)
Realized mark-to-market	**257.7**	85.4	123.5
Total mark-to-market results recorded in earnings	**$ 408.8**	$ 99.1	$ 36.2

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

Origination gains arise primarily from contracts that our wholesale marketing and risk management operation structures to meet the risk management needs of our customers. Transactions that result in origination gains may be unique and provide the potential for individually significant gains from a single transaction.

Origination gains represent the initial fair value recognized on these structured transactions. The recognition of origination gains is dependent on the existence of observable market data that validates the initial fair value of the contract. Origination gains arose primarily from:

6 transactions completed in 2005, one of which contributed approximately $35 million pre-tax,

7 transactions completed in 2004, of which no transaction contributed in excess of $10 million pre-tax, and

14 transactions completed in 2003, of which one transaction contributed approximately $10 million pre-tax.

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

Risk management and trading represents both realized and unrealized gains and losses from changes in the value of our portfolio, including the recognition of gains associated with decreases in the close-out adjustment when we are able to obtain sufficient market price information. We discuss the changes in mark-to-market results recorded in earnings on the next page. We show the relationship between our mark-to-market results recorded in earnings and the change in our net mark-to-market energy asset later on the next page.

Mark-to-market results recorded in earnings increased $309.7 million in 2005 compared to 2004 due to:

- approximately $260 million primarily related to a higher level of risk management and trading activities. Increases in our gas and coal activities, higher commodity price volatility, and greater market liquidity resulted in more opportunities to deploy risk capital and to earn additional returns in 2005 compared to 2004. These items resulted in an increased number of transactions that were entered into and realized during 2005 and a higher level of open positions that resulted in increased gains in 2005 compared to 2004. During 2005, slightly more than half of the mark-to-market results were derived from power, approximately one-third from gas, and the remainder from other transactions.

- $41.9 million related to a higher level of origination gains as discussed on the previous page, and

- $49.9 million related to the decrease in the close-out adjustment during 2005 compared to the prior year for transactions that we have now observed sufficient market price information and/or we realized cash flows since the transactions' inception.

These increases in mark-to-market results recorded in earnings were partially offset by the impact of $41.5 million of higher mark-to-market losses on certain economic hedges that did not qualify for cash-flow hedge accounting treatment. We discuss these economic hedges in more detail below.

Mark-to-market results recorded in earnings increased $62.9 million in 2004 compared to 2003 mostly because of the impact of lower mark-to-market losses on economic hedges that do not qualify for hedge accounting treatment as discussed in more detail below and lower losses from risk management and trading activities primarily due to favorable changes in regional power prices, and price volatility. These increases were partially offset by a lower level of origination gains in 2004 compared to 2003. The lower level of origination gains is primarily due to higher individually significant gains on contracts in 2003 that had a positive impact in that period.

Changing forward prices result in shifting value between accrual contracts and the associated mark-to-market positions of certain contracts in New England that contain fuel adjustment clauses and gas transportation contract hedges, producing a timing difference in the recognition of earnings on these transactions. These mark-to-market hedges are economically effective; however, they do not qualify for cash-flow hedge accounting under SFAS No. 133. As a result, we recorded $41.2 million of pre-tax losses in 2005, $0.3 million of pre-tax gains in 2004, and pre-tax losses of $47.4 million in 2003. These mark-to-market gains and losses will be offset as we realize the related accrual load-serving positions in cash.

Mark-to-Market Energy Assets and Liabilities

Our mark-to-market energy assets and liabilities are comprised of derivative contracts. While some of our mark-to-market contracts represent commodities or instruments for which prices are available from external sources, other commodities and certain contracts are not actively traded and are valued using other pricing sources and modeling techniques to determine expected future market prices, contract quantities, or both. We discuss our modeling techniques later in this section.

Mark-to-market energy assets and liabilities consisted of the following:

At December 31,	**2005**	**2004**
	(In millions)	
Current Assets	**$ 1,339.2**	$ 567.3
Noncurrent Assets	**1,089.3**	359.8
Total Assets	**2,428.5**	927.1
Current Liabilities	**1,348.7**	559.7
Noncurrent Liabilities	**912.3**	315.0
Total Liabilities	**2,261.0**	874.7
Net mark-to-market energy asset	**$ 167.5**	$ 52.4

The following are the primary sources of the change in net mark-to-market energy asset during 2005 and 2004:

	2005		2004	
		(In millions)		
Fair value beginning of year		**$ 52.4**		$ 18.8
Changes in fair value recorded in earnings				
Origination gains	**$ 61.6**		$ 19.7	
Unrealized changes in fair value	**347.2**		79.4	
Changes in valuation techniques				
Reclassification of settled contracts to realized	**(257.7)**		(85.4)	
Total changes in fair value recorded in earnings		**151.1**		13.7
Contracts acquired		**17.4**		
Changes in value of exchange-listed futures and options		**(119.9)**		(15.8)
Net change in premiums on options		**79.7**		29.4
Other changes in fair value		**(13.2)**		6.3
Fair value at end of year		**$ 167.5**		$ 52.4

Changes in the net mark-to-market energy asset that affected earnings were as follows:

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

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

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

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

The net mark-to-market energy asset also changed due to the following items recorded in accounts other than in our Consolidated Statements of Income:

Contracts acquired represents the initial fair value of acquired derivative contracts recorded in "Mark-to-market energy assets."

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

Net changes in premiums on options reflects the accounting for premiums on options purchased as an increase in the net mark-to-market energy asset and premiums on options sold as a decrease in the net mark-to-market energy asset.

The settlement terms of our net mark-to-market energy asset and sources of fair value as of December 31, 2005 are as follows:

	Settlement Term							
	2006	**2007**	**2008**	**2009**	**2010**	**2011**	**Thereafter**	**Fair Value**
				(In millions)				
Prices provided by external sources (1)	$ (12.6)	$ 63.5	$ 81.8	$ (2.7)	$ (2.1)	$	$	$ 127.9
Prices based on models	3.1	4.7	10.2	(0.6)	17.5	1.4	3.3	39.6
Total net mark-to-market energy asset	$ (9.5)	$ 68.2	$ 92.0	$ (3.3)	$ 15.4	$ 1.4	$ 3.3	$ 167.5

(1) Includes contracts actively quoted and contracts valued from other external sources.

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

Consistent with our risk management practices, we have presented the information in the table above based upon the ability to obtain reliable prices for components of the risks in our contracts from external sources rather than on a contract-by-contract basis. Thus, the portion of long-term contracts that is valued using external price sources is presented under the caption "prices provided by external sources." This is consistent with how we manage our risk, and we believe it provides the best indication of the basis for the valuation of our portfolio. Since we manage our risk on a portfolio basis rather than contract-by-contract, it is not practicable to determine separately the portion of long-term contracts that is included in each valuation category. We describe the commodities, products, and delivery periods included in each valuation category in detail below.

The amounts for which fair value is determined using prices provided by external sources represent the portion of forward, swap, and option contracts for which price quotations are available through brokers or over-the-counter transactions. The term for which such price information is available varies by commodity, region, and product. The fair values included in this category are the following portions of our contracts:

- forward purchases and sales of electricity during peak and off-peak hours for delivery terms primarily through 2008, but up to 2010, depending upon the region,
- options for the purchase and sale of electricity during peak hours for delivery terms through 2008, depending upon the region,
- forward purchases and sales of electric capacity for delivery terms primarily through 2007, but up to 2008, depending on the region,
- forward purchases and sales of natural gas, coal, and oil for delivery terms through 2009, and
- options for the purchase and sale of natural gas, coal, and oil for delivery terms through 2008.

The remainder of the net mark-to-market energy asset is valued using models. The portion of contracts for which such techniques are used includes standard products for which external prices are not available and customized products that are valued using modeling techniques to determine expected future market prices, contract quantities, or both.

Modeling techniques include estimating the present value of cash flows based upon underlying contractual terms and incorporate, where appropriate, option pricing models and statistical and simulation procedures. Inputs to the models include:

- observable market prices,
- estimated market prices in the absence of quoted market prices,
- the risk-free market discount rate,
- volatility factors,
- estimated correlation of energy commodity prices, and
- expected generation profiles of specific regions.

Additionally, we incorporate counterparty-specific credit quality and factors for market price and volatility uncertainty and other risks in our valuation. The inputs and factors used to determine fair value reflect management's best estimates.

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

Consistent with our risk management practices, the amounts shown in the table on the previous page as being valued using prices from external sources include the portion of long-term contracts for which we can obtain reliable prices from external sources. The remaining portions of these long-term contracts are shown in the table as being valued using models. In order to realize the entire value of a long-term contract in a single transaction, we would need to sell or assign the entire contract. If we were to sell or assign any of our long-term contracts in their entirety, we may not realize the entire value reflected in the table. However, based upon the nature of the wholesale marketing and risk management operation, we expect to realize the value of these contracts, as well as any contracts we may enter into in the future to manage our risk, over time as the contracts and related hedges settle in accordance with their terms. We do not expect to realize the value of these contracts and related hedges by selling or assigning the contracts themselves in total.

The fair values in the table represent expected future cash flows based on the level of forward prices and volatility factors as of December 31, 2005 and could change significantly as a result of future changes in these factors. Additionally, because the depth and liquidity of the power markets vary substantially between regions and time periods, the prices used to determine fair value could be affected significantly by the volume of transactions executed.

Management uses its best estimates to determine the fair value of commodity and derivative contracts it holds and sells. These estimates consider various factors including closing exchange and over-the-counter price quotations, time value, volatility factors, and credit exposure. However, future market prices and actual quantities will vary from those used in recording mark-to-market energy assets and liabilities, and it is possible that such variations could be material.

Risk Management Assets and Liabilities

We record derivatives that qualify for designation as hedges under SFAS No. 133 in "Risk management assets and liabilities" in our Consolidated Balance Sheets. Our risk management assets and liabilities consisted of the following:

At December 31,	**2005**	**2004**
	(In millions)	
Current Assets	**$ 1,244.3**	$ 471.5
Noncurrent Assets	**626.0**	306.2
Total Assets	**1,870.3**	777.7

At December 31,		**2005**		2004
Current Liabilities		**483.5**		304.3
Noncurrent Liabilities		**1,035.5**		472.2
Total Liabilities		**1,519.0**		776.5
Net risk management asset	**$**	**351.3**	$	1.2

The significant increases in our gross risk management assets and liabilities were due primarily to higher commodity prices during 2005. These price increases resulted in larger positions with individual counterparties which must be recorded gross in our balance sheet unless a legal right of offset exists. The significant increase in our net risk management asset was due primarily to a contract that was previously designated as a cash-flow hedge that we elected to de-designate and to which the normal purchase and normal sales election was applied. At the point of de-designation, the fair value of the contract that was previously recorded in "Risk management liabilities" was reclassified to "Unamortized energy contract liabilities." These increases in our net risk management asset were partially offset by the assumption of below-market power sale agreements in connection with a customer contract restructuring. We discuss the de-designation of the cash-flow hedge in more detail on the next page. We discuss the customer contract restructuring transaction in more detail in *Note 4*.

Unamortized Energy Contract Assets and Liabilities

Unamortized energy contract assets and liabilities represent the remaining unamortized balance of nonderivative energy contracts that we acquired or derivatives designated as normal purchases and normal sales that we had previously recorded as "Mark-to-market energy assets and liabilities" or "Risk management assets and liabilities." Our unamortized energy contract assets and liabilities consisted of the following:

At December 31,	**2005**	**2004**
	(In millions)	
Current Assets	**$ 55.6**	$ 37.2
Noncurrent Assets	**141.2**	80.1
Total Assets	**$ 196.8**	$ 117.3
Current Liabilities	**$ 489.5**	$ 67.2
Noncurrent Liabilities	**1,118.7**	86.2
Total Liabilities	**$ 1,608.2**	$ 153.4

During 2005, we acquired several pre-existing nonderivative contracts that had been originated by other parties in prior periods when market prices were lower than current levels. Upon acquisition, we received approximately $530 million in cash and other consideration and recorded a liability in "Unamortized energy contracts." In addition, during 2005, we designated as normal purchases and normal sales contracts that we had previously recorded as cash-flow hedges in "Risk management liabilities." This change in designation resulted in a reclassification of $888.5 million from "Risk management liabilities" to "Unamortized energy contracts." Since the original forecasted transaction is still probable of occurring, the amount recorded in "Accumulated other comprehensive income" upon de-designation of the hedged position will remain and be amortized along with the unamortized energy contract liability. The de-designation and reclassification had no impact on our earnings.

<u>Other</u>

	2005	**2004**	**2003**
		(In millions)	
Revenues	**$ 58.0**	$ 73.6	$ 45.1

Our merchant energy business holds up to a 50% voting interest in 24 operating domestic energy projects that consist of electric generation, fuel processing, or fuel handling facilities. Of these 24 projects, 17 are "qualifying facilities" that receive certain exemptions based on the facilities' energy source or the use of a cogeneration process. Earnings from our investments were $3.6 million in 2005, $18.0 million in 2004, and $2.1 million in 2003.

Other revenues decreased $15.6 million in 2005 compared to 2004 mostly due to an increased incentive fee and a deferred contingent transaction fee received from our synthetic fuel facilities located in Virginia and West Virginia that had a favorable impact in 2004.

The increase in revenues in 2004 compared to 2003 is primarily due to higher equity in earnings related to our minority investment in a facility that produces synthetic fuel from coal. This increase included $13.1 million of revenues related to an increased incentive fee and a deferred contingent transaction fee.

At December 31, 2005, our investment in qualifying facilities and domestic power projects consisted of the following:

Book Value at December 31,	**2005**	**2004**
	(In millions)	
Project Type		
Coal	**$ 127.8**	$ 128.7
Hydroelectric	**55.9**	55.8

Book Value at December 31,	2005	2004
Geothermal	**43.7**	46.3
Biomass	**48.0**	50.2
Fuel Processing	**23.8**	22.5
Solar	**7.0**	10.4
Total	**$ 306.2**	$ 313.9

We believe the current market conditions for our equity-method investments that own geothermal, coal, hydroelectric, and fuel processing projects provide sufficient positive cash flows to recover our investments. We continuously monitor issues that potentially could impact future profitability of these investments, including environmental and legislative initiatives. We discuss certain risks and uncertainties in more detail in our *Forward Looking Statements* and *Item 1A. Risk Factors* sections. However, should future events cause these investments to become uneconomic, our investments in these projects could become impaired under the provisions of APB No. 18.

The ability to recover our costs in our equity-method investments that own biomass and solar projects is partially dependent upon subsidies from the State of California. Under the California Public Utility Act, subsidies currently exist in that the California Public Utilities Commission (CPUC) requires load-serving entities to identify a separate rate component to be collected from customers to fund the development of renewable resources technologies, including solar, biomass, and wind facilities. In addition, legislation in California requires that each load-serving entity increase its total procurement of eligible renewable energy resources by at least one percent per year so that 20% of its retail sales are procured from eligible renewable energy resources by 2017. The CPUC accelerated the deadline for compliance to 2010. The legislation also requires the California Energy Commission to award supplemental energy payments to load-serving entities to cover above-market costs of renewable energy.

Given the need for electric power and the desire for renewable resource technologies, we believe California will continue to subsidize the use of renewable energy to make these projects economical to operate. However, should the California legislation fail to adequately support the renewable energy initiatives, our equity-method investments in these types of projects could become impaired under the provisions of APB No. 18, and any losses recognized could be material. If our strategy were to change from an intent to hold to an intent to sell for any of our equity-method investments in qualifying facilities or power projects, we would need to adjust their book value to fair value, and that adjustment could be material. If we were to sell these investments in the current market, we may have losses that could be material.

Operating Expenses

Our merchant energy business operating expenses increased $191.5 million in 2005 compared to 2004 mostly due to the following:

- an increase of $101.8 million at our wholesale marketing and risk management operation due to an increase in compensation and benefit costs including our expanding gas and coal operations,
- an increase of $81.5 million from Ginna, which was acquired in June 2004,
- an increase of $26.5 million at our retail operation primarily related to a $10.8 million increase in uncollectible expenses and a $8.7 million increase in aggregator fees,
- an increase of $13.9 million at our gas-fired generating facilities primarily due to increased corporate overhead expenses, and
- an increase of $13.0 million at Calvert Cliffs primarily due to an increase in corporate overhead expenses, partially offset by fewer employees and a shorter refueling outage in 2005.

These increases in expense were partially offset by lower operating expenses of $56.5 million at Nine Mile Point primarily due to lower refueling outage expenses and a lower number of employees and contractors.

Our merchant energy business operating expenses increased $240.0 million in 2004 compared to 2003 mostly due to the following:

- an increase of $94.3 million primarily related to higher compensation, benefit, and other inflationary costs, higher Sarbanes-Oxley 404 implementation costs of approximately $10 million, and higher spending on enterprise-wide information technology infrastructure costs of approximately $5 million,
- an increase at our competitive supply operations totaling $90.1 million mostly because of higher compensation and benefit expense, including an increased number of employees to support the growth of these operations,
- an increase in expenses due to the June 2004 acquisition of Ginna totaling $43.1 million, and
- an increase of $10.1 million at our Nine Mile Point nuclear facility primarily due to refueling outage and reliability spending.

Merger-Related Transaction Costs

We discuss our pending merger with FPL Group and related costs as discussed in more detail in *Note 15*.

Workforce Reduction Costs

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

Depreciation, Depletion, and Amortization Expense

Merchant energy depreciation, depletion, and amortization expenses increased $30.4 million in 2005 compared to 2004 mostly due to:

- $10.2 million related to our South Carolina synthetic fuel facility,

- $8.8 million related to Ginna, which was acquired in June 2004, and
- $6.0 million increase related to our 2005 investments in gas producing facilities.

Merchant energy depreciation and amortization expense increased $24.6 million in 2004 compared to 2003 mostly due to:

- $10.3 million related to Ginna,
- $6.9 million related to our High Desert facility, which commenced operations in 2003, and
- $5.1 million related to our South Carolina synthetic fuel facility, which was acquired in May 2003.

Accretion of Asset Retirement Obligations

The increase in accretion expense of $8.9 million in 2005 compared to 2004 and $10.5 million in 2004 compared to 2003 is primarily due to Ginna which was acquired in June 2004 and the impact of normal compounding.

Taxes Other Than Income Taxes

Merchant energy taxes other than income taxes increased $23.7 million in 2005 compared to 2004 mostly due to $19.6 million related to higher gross receipts taxes at our retail electric operation and $4.0 million related to property taxes for Ginna.

Regulated Electric Business

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

Results

	2005	2004	2003
		(In millions)	
Revenues	**$ 2,036.5**	$ 1,967.7	$ 1,921.6
Electricity purchased for resale expenses	**(1,068.9)**	(1,034.0)	(1,023.5)
Operations and maintenance expenses	**(318.4)**	(304.2)	(305.1)
Merger-related transaction costs	**(4.0)**		
Workforce reduction costs			(0.6)
Depreciation and amortization	**(185.8)**	(194.2)	(181.7)
Taxes other than income taxes	**(135.3)**	(132.8)	(130.2)
Income from Operations	**$ 324.1**	$ 302.5	$ 280.5
Net Income	**$ 149.4**	$ 131.1	$ 107.5
Other Items Included in Operations (after-tax)			
Merger-related transaction costs	**$ (3.7)**		
Workforce reduction costs			(0.4)
Total Other Items	**$ (3.7)**	$	$ (0.4)

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

Net income from the regulated electric business increased $18.3 million in 2005 compared to 2004 mostly because of the following:

- increased revenues less electricity purchased for resale expenses of $20.7 million after-tax,
- decreased depreciation and amortization expense of $5.1 million after-tax, and
- increased other income primarily due to gains on the sales of land of $3.6 million after-tax.

These favorable results were partially offset by the following:

- increased operations and maintenance expenses of $8.7 million after-tax mostly due to higher compensation and benefit costs and the impact of inflation on other costs, and
- merger-related transaction costs of $3.7 million after-tax.

Net income from the regulated electric business increased $23.6 million in 2004 compared to 2003 mostly because of the following:

- increased revenues less electricity purchased for resale expenses of $21.5 million after-tax,
- the absence of $19.4 million after-tax of incremental distribution service restoration expenses associated with Hurricane Isabel in 2003, and

lower interest expense of $10.0 million after-tax.

These favorable results were partially offset by the following:

excluding the costs associated with Hurricane Isabel, we had increased operations and maintenance expenses of $18.9 million after-tax mostly due to higher compensation and benefit costs, and the impact of inflation on other costs, higher uncollectible expenses, Sarbanes-Oxley 404 implementation costs, and increased spending on electric system reliability, and

increased depreciation and amortization expense of $7.6 million after-tax.

Electric Revenues

The changes in electric revenues in 2005 and 2004 compared to the respective prior year were caused by:

		2005		2004
		(In millions)		
Distribution volumes	**$**	**21.3**	$	15.8
Standard offer service		**38.8**		26.6
Total change in electric revenues from electric system sales		**60.1**		42.4
Other		**8.7**		3.7
Total change in electric revenues	**$**	**68.8**	$	46.1

<u>*Distribution Volumes*</u>

Distribution volumes are the amount of electricity that BGE delivers to customers in its service territory. The percentage changes in our electric system distribution volumes, by type of customer, in 2005 and 2004 compared to the respective prior year were:

	2005	2004
Residential	**3.4%**	4.4%
Commercial	**5.1**	0.9
Industrial	**(6.4)**	(8.0)

In 2005, we distributed more electricity to residential customers compared to 2004 mostly due to warmer summer weather and an increased number of customers. We distributed more electricity to commercial customers mostly due to increased usage per customer, an increased number of customers, and warmer summer weather. We distributed less electricity to industrial customers mostly due to decreased usage per customer.

In 2004, we distributed more electricity to residential customers compared to 2003 mostly due to increased usage per customer, an increased number of customers, and warmer summer weather. We distributed about the same amount of electricity to commercial customers. We distributed less electricity to industrial customers mostly due to lower usage by industrial customers.

<u>*Standard Offer Service*</u>

BGE provides standard offer service for customers that do not select an alternative supplier as discussed in *Item 1. Business Electric Regulatory Matters and Competition* section.

Standard offer service revenues increased in 2005 compared to 2004 mostly because of increased standard offer service volumes to residential customers and increased standard offer service rates for all customers partially offset by lower standard offer service volumes associated with those commercial and industrial customers that elected alternative suppliers beginning July 1, 2004.

Standard offer service revenues increased in 2004 compared to 2003 mostly because of increased standard offer service volumes to residential customers, partially offset by lower revenues associated with commercial and industrial customers that elected an alternative supplier beginning July 1, 2004.

Electricity Purchased for Resale Expenses

BGE's actual costs of electricity purchased for resale expenses increased $34.9 million in 2005 compared to 2004 mostly because of increased standard offer service volumes to residential customers and higher costs to serve all standard offer service customers, partially offset by lower electricity purchased for resale expenses associated with commercial and industrial customers that elected alternative suppliers beginning July 1, 2004.

BGE's actual costs of electricity purchased for resale expenses increased $10.5 million in 2004 compared to 2003 mostly because of increased standard offer service volumes to residential customers and higher costs to serve all standard offer service customers, partially offset by lower electricity purchased for resale expenses associated with commercial and industrial customers that elected an alternative supplier beginning July 1, 2004.

Electric Operations and Maintenance Expenses

Regulated electric operations and maintenance expenses increased $14.2 million in 2005 compared to 2004 mostly due to higher compensation and benefit costs and the impact of inflation on other costs.

Regulated electric operations and maintenance expenses were about the same in 2004 compared to 2003. Hurricane Isabel caused $32.1 million of incremental distribution service restoration expenses in 2003. Other operations and maintenance expenses increased $31.2 million in 2004 compared to 2003. This increase was mostly due to:

- an increase in compensation and benefit cost, and the impact of inflation on other costs,
- a $9.0 million increase in uncollectible expenses,
- approximately $4 million related to Sarbanes-Oxley 404 implementation costs, and
- approximately $4 million in spending on electric systems reliability.

Merger-Related Transaction Costs

We discuss our pending merger with FPL Group and related costs in more detail in *Note 15*.

Workforce Reduction Costs

BGE's electric business recognized expenses associated with our workforce reduction efforts as discussed in *Note 2*.

Electric Depreciation and Amortization Expense

Regulated electric depreciation and amortization expense decreased $8.4 million in 2005 compared to 2004 mostly because of the absence of $12.6 million of accelerated amortization expense associated with certain information technology assets replaced in 2004, partially offset by $4.2 million related to additional property placed in service.

Regulated electric depreciation and amortization expense increased $12.5 million in 2004 compared to 2003 mostly because of $7.6 million related to accelerated amortization expense associated with the replacement of information technology assets and $4.9 million related to additional property placed in service.

Regulated Gas Business

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

Results

	2005	2004	2003
		(In millions)	
Revenues	**$ 972.8**	$ 757.0	$ 726.0
Gas purchased for resale expenses	**(687.5)**	(484.3)	(445.8)
Operations and maintenance expenses	**(131.8)**	(123.6)	(101.1)
Merger-related transaction costs	**(1.4)**		
Workforce reduction costs			(0.1)
Depreciation and amortization	**(46.6)**	(48.1)	(46.6)
Taxes other than income taxes	**(33.1)**	(32.1)	(27.9)
Income from Operations	**$ 72.4**	$ 68.9	$ 104.5
Net Income	**$ 26.7**	$ 22.2	$ 43.0
Other Items Included in Operations (after-tax)			
Merger-related transaction costs	**$ (1.3)**	$	$
Workforce reduction costs			(0.1)
Total Other Items	**$ (1.3)**	$	$ (0.1)

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

Net income from our regulated gas business was about the same in 2005 compared to 2004.

Net income from our regulated gas business decreased $20.8 million in 2004 compared to 2003 mostly because of:

- increased operations and maintenance expenses of $13.6 million after-tax mostly due to increased compensation, benefit, and other inflationary costs, higher uncollectible expenses, and Sarbanes-Oxley 404 implementation costs,
- the absence of a $4.7 million after-tax recovery of a previously disallowed regulatory asset following an order issued by the Maryland PSC that had a positive impact in 2003, and
- the absence of $2.2 million after-tax of property tax refund claims by the State of Maryland resulting from a reclassification of gas distribution pipeline from real property to personal property that had a positive impact in 2003.

Gas Revenues

The changes in gas revenues in 2005 and 2004 compared to the respective prior year were caused by:

	2005	2004
	(In millions)	
Distribution volumes	**$ 3.9**	$ (7.2)
Base rates	**2.6**	(0.1)

		2005		2004
Weather normalization		**2.5**		5.4
Gas cost adjustments		**129.1**		40.5
Total change in gas revenues from gas system sales		**138.1**		38.6
Off-system sales		**77.5**		(7.6)
Other		**0.2**		
Total change in gas revenues	**$**	**215.8**	$	31.0

Distribution Volumes

The percentage changes in our distribution volumes, by type of customer, in 2005 and 2004 compared to the respective prior year were:

	2005	2004
Residential	**(1.3)%**	(5.1)%
Commercial	**(9.0)**	10.1
Industrial	**33.6**	(22.3)

In 2005, we distributed less gas to residential and commercial customers compared to 2004 mostly due to decreased usage per customer partially offset by colder winter weather and an increased number of customers. We distributed more gas to industrial customers mostly due to increased usage per customer.

In 2004, we distributed less gas to residential customers compared to 2003 mostly due to milder winter weather and lower usage per customer. We distributed more gas to commercial customers mostly due to increased usage and an increased number of customers. We distributed less gas to industrial customers mostly due to lower usage per customer.

Base Rates

In April 2005, BGE filed an application for a $52.7 million annual increase in its gas base rates. The Maryland PSC issued an order in December 2005 granting BGE an annual increase of $35.6 million. Certain parties to the proceeding have sought judicial review and Maryland PSC rehearing of the decision. BGE will not seek review of any aspect of the order. We cannot provide assurance that a court will not reverse any aspect of the order or that it will not remand certain issues to the Maryland PSC.

Weather Normalization

The Maryland PSC allows us to record a monthly adjustment to our gas distribution revenues to eliminate the effect of abnormal weather patterns on our gas distribution volumes. This means our monthly gas distribution revenues are based on weather that is considered "normal" for the month and, therefore, are not affected by actual weather conditions.

Gas Cost Adjustments

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

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

Gas cost adjustment revenues increased in 2005 compared to 2004 because we sold more gas at higher prices.

Gas cost adjustment revenues increased in 2004 compared to 2003 because we sold gas at a higher price partially offset by less gas sold.

Off-System Sales

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

Revenues from off-system gas sales increased in 2005 compared to 2004 because we sold more gas at higher prices.

Revenues from off-system gas sales decreased in 2004 compared to 2003 mostly because of less gas sold.

Gas Purchased For Resale Expenses

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

Gas purchased for resale expenses increased in 2005 compared to 2004 because we purchased more gas at higher prices.

Gas purchased for resale expenses increased in 2004 as compared to 2003 mostly because of higher gas prices partially offset by less gas sold.

Gas Operations and Maintenance Expenses

Regulated gas operations and maintenance expenses increased $8.2 million in 2005 compared to 2004 mostly due to higher compensation and benefit costs and the impact of inflation on other costs.

Regulated gas operations and maintenance expenses increased $22.5 million in 2004 compared to 2003 mostly because of:

- an increase in compensation and benefit cost, and the impact of inflation on other costs,
- a $5.4 million increase in uncollectible expenses, and
- approximately $1 million related to Sarbanes-Oxley 404 implementation costs.

Merger-Related Transaction Costs

We discuss our pending merger with FPL Group and related costs in more detail in *Note 15*.

Workforce Reduction Costs

BGE's gas business recognized expenses associated with our workforce reduction efforts as discussed in *Note 2*.

Other Nonregulated Businesses

Results

	2005	2004	2003
		(In millions)	
Revenues	$ **207.0**	$ 201.1	$ 399.6
Operating expenses	**(156.2)**	(180.0)	(355.1)
Merger-related transaction costs	**(0.4)**		
Workforce reduction costs			(0.2)
Depreciation and amortization	**(40.2)**	(24.2)	(11.0)
Taxes other than income taxes	**(2.0)**	(2.4)	(3.3)
Income from Operations	$ **8.2**	$ (5.5)	$ 30.0
Income from continuing operations and before cumulative effects of changes in accounting principles (after-tax)	$ **0.4**	$ (12.9)	$ 5.1
Income from discontinued operations (after-tax)	**20.6**	9.4	7.1
Cumulative effects of changes in accounting principles (after-tax)	**0.2**		
Net Income (Loss)	$ **21.2**	$ (3.5)	$ 12.2
Other Items Included In Operations (after-tax)			
Merger-related transaction costs	$ **(0.2)**		
Workforce reduction costs			(0.1)
Total Other Items	$ **(0.2)**	$	$ (0.1)

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

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

Net income from our other nonregulated businesses increased $24.7 million in 2005 compared to 2004 primarily due to:

- a $16.1 million after-tax gain on sale of Constellation Power International Investments, Ltd., which held our other nonregulated international investments, in October 2005,
- a $13.2 million after-tax increase in net income from the continued liquidation of our financial investments.

These increases were partially offset by $4.9 million lower net income from our other nonregulated international investments due to their sale in October 2005. We discuss the sale of our other nonregulated international investments in more detail in *Note 2*.

Net income from our other nonregulated businesses decreased $15.7 million during 2004 compared to 2003 mostly because of a $16.4 million after-tax net gain on sales of investments and other assets in 2003 that had a positive impact in that period.

In 2001, we decided to sell certain non-core assets and accelerate the exit strategies on other assets that we continued to hold and own. While our intent is to dispose of these remaining non-core assets, market conditions and other events beyond our control may affect the actual sale of these assets. In addition, a future decline in the fair value of these assets could result in losses that could have a material impact on our financial results.

Consolidated Nonoperating Income and Expenses

Other Income

Other income increased $37.5 million in 2005 compared to 2004 primarily because of higher interest and investment income due to a higher cash balance and higher decommissioning trust asset earnings and gains on the sales of land at BGE.

Other income increased $4.6 million during 2004 as compared to 2003 mostly because of higher earnings from consolidated investments where our ownership is less than 100%, which resulted in increased minority interest expense.

Total other income at BGE increased $12.3 million in 2005 compared to 2004 primarily due to approximately $7 million of gains on the sales of land.

Fixed Charges

Total fixed charges decreased $16.7 million in 2005 compared to 2004 mostly because of the benefit of lower interest rates due to interest rate swaps entered into during the third quarter of 2004 and a lower level of debt outstanding. We discuss the interest rate swaps in more detail in *Note 13*.

Total fixed charges decreased $9.7 million during 2004 as compared to 2003 mostly because of a lower level of debt outstanding and the benefit of lower interest rates due to interest rate swaps entered into during the third quarter of 2004.

Total fixed charges for BGE decreased $2.7 million in 2005 compared to 2004 mostly because of a lower level of debt outstanding.

Total fixed charges for BGE decreased $15.0 million during 2004 compared to 2003 mostly because of a lower level of debt outstanding.

Income Taxes

The differences in income taxes result from a combination of the changes in income and the impact of the recognition of tax credits on the effective tax rate. We include an analysis of the changes in the effective tax rate in *Note 10*.

The Internal Revenue Code provides for a phase-out of synthetic fuel tax credits if average annual wellhead oil prices increase above certain levels. Each year, we are required to compare average annual wellhead oil prices per barrel as published by the Internal Revenue Service (IRS) (reference price) to a Gross National Product inflation adjusted oil price for the year, also published by the IRS. The reference price is determined based on wellhead prices for all domestic oil production as published by the Energy Information Administration. For the twelve months ended December 31, 2005, we estimate that the reference price averaged approximately $6 per barrel lower than the NYMEX price for light, sweet crude oil. For 2006, we estimate the credit reduction would begin if the reference price exceeds approximately $54 per barrel and would be fully phased out if the reference price exceeds approximately $68 per barrel.

If oil prices remain at high levels, a portion of our synthetic fuel tax credits could be phased-out in 2006 and 2007. Market forwards and volatilities as of mid-February 2006 would indicate a 25-35% tax credit phase-out (approximately $35-$50 million) in 2006.

We actively monitor and manage our exposure to synthetic fuel tax credit phase-out as part of our ongoing hedging activities. In addition, we may reduce synthetic fuel production depending on our expectation of the level of tax credit phase-out. The objective of these activities is to reduce the potential losses we could incur if the reference price in a year exceeds a level triggering a phase-out of synthetic fuel tax credits.

While we believe the production and sale of synthetic fuel from all of our synthetic fuel facilities meet the conditions to qualify for tax credits under the IRC, we cannot predict the timing or outcome of any future challenge by the IRS, legislative or regulatory action, oil prices, the effectiveness of our hedging program, or the ultimate impact of such events on the synthetic fuel tax credits that we have claimed to date or expect to claim in the future, but the impact could be material to our financial results.

Pension Expense

Our actual return on our qualified pension plan assets was 7.4% for the year ended December 31, 2005. In 2005, we assumed an expected return on pension plan assets of 9.0% for the purpose of computing annual net periodic pension expense in accordance with SFAS No. 87, *Employers' Accounting for Pensions*. Differences between actual and expected returns are deferred along with other actuarial gains and losses and reflected in future net periodic pension expense in accordance with SFAS No. 87. Expected and actual returns on pension assets also are affected by plan contributions. Effective in 2006, we have reduced our assumed expected return on pension plan assets from 9.0% to 8.75% based on a fundamental analysis utilizing expected long-term returns applied to our targeted asset allocation.

Effective December 31, 2005, we also changed the mortality table we are utilizing to determine our benefit obligation and annual expense to reflect more current life expectancy experience.

The combined impact of these changes will increase 2006 and subsequent year pension and postretirement benefit expense by approximately $14 million.

We expect to contribute $52 million to our pension plans in 2006, even though there is no required IRS minimum contribution for 2006.

At December 31, 2005, we recorded an after-tax charge to equity of $77.1 million as a result of increasing our additional minimum pension liability. We discuss our pension plans in more detail in *Note 7*.

Financial Condition

Cash Flows

The following table summarizes our 2005 cash flows by business segment, as well as our consolidated cash flows for 2005, 2004, and 2003.

	2005 Segment Cash Flows			Consolidated Cash Flows		
	Merchant	Regulated	Other	2005	2004	2003
			(In millions)			
Operating Activities						
Net income	$ 425.8	$ 176.1	$ 21.2	$ 623.1	$ 539.7	$ 277.3
Non-cash adjustments to net income	475.8	220.9	55.0	751.7	916.4	944.2
Changes in working capital	(686.7)	(64.0)	(24.6)	(775.3)	(319.6)	(50.0)
Pension and postemployment benefits*				23.6	(3.0)	(69.4)
Other	(13.8)	(33.8)	51.7	4.1	(46.7)	(44.3)
Net cash provided by operating activities	201.1	299.2	103.3	627.2	1,086.8	1,057.8
Investing activities						
Investments in property, plant and equipment	(464.7)	(269.3)	(26.0)	(760.0)	(703.6)	(635.7)
Contract and portfolio acquisitions	(336.2)			(336.2)		
Asset acquisitions and business combinations, net of cash acquired	(216.3)		(20.9)	(237.2)	(457.3)	(546.6)
Investment in nuclear decommissioning trust fund securities	(370.8)			(370.8)	(424.2)	(176.0)
Proceeds from nuclear decommissioning trust funds securities	353.2			353.2	402.2	162.8
Net proceeds from sale of discontinued operations	217.6		71.8	289.4	72.7	
Sale of investments and other assets	0.4	11.0	3.0	14.4	36.1	148.8
Issuances of loans receivable	(82.8)			(82.8)		
Other investments	(36.8)	(10.4)	3.2	(44.0)	(78.6)	(113.6)
Net cash (used in) provided by investing activities	(936.4)	(268.7)	31.1	(1,174.0)	(1,152.7)	(1,160.3)
Cash flows from operating activities less cash flows from investing activities	$ (735.3)	$ 30.5	$ 134.4	(546.8)	(65.9)	(102.5)
Financing Activities						
Net (repayment) issuance of debt*				(339.6)	(152.8)	274.9
Proceeds from issuance of common stock*				96.9	293.9	95.4
Common stock dividends paid*				(228.8)	(189.7)	(169.2)
Proceeds from contract and portfolio acquisitions				1,026.9	117.5	
Other*				98.1	(18.0)	7.7
Net cash provided by financing activities				653.5	50.9	208.8
Net increase (decrease) in cash and cash equivalents				$ 106.7	$ (15.0)	$ 106.3

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

Cash Flows from Operating Activities

Cash provided by operating activities was $627.2 million in 2005 compared to $1,086.8 million in 2004. Net income was higher by $83.4 million in 2005 compared to 2004. Non-cash adjustments to net income were $164.7 million lower in 2005 compared to 2004. The decrease in non-cash adjustments to net income was primarily due to the reclassification of $72.6 million of proceeds from derivative power sales contracts as financing activities under SFAS No. 149, *Amendment of FASB Statement No. 133 on Derivative and Hedging Activities* and $63.9 million related to the impact of discontinued operations.

Changes in working capital had a negative impact of $775.3 million on cash flow from operations in 2005 compared to a negative impact of $319.6 million in 2004. The decrease of $455.7 million was due to a $598 million unfavorable change in working capital primarily related to our accounts receivable, accounts payable, and fuel stocks mostly due to higher commodity prices, increased value of emissions credits, and business growth. This was partially offset by an increase of $142 million of net cash collateral received, which was also due to higher commodity prices.

Cash provided by operating activities was $1,086.8 million in 2004 compared to $1,057.8 million in 2003. Non-cash adjustments to net income were $27.8 million lower in 2004 compared to 2003. The decrease in non-cash adjustments to net income was primarily due to the cumulative effects of changes in accounting principles of $198.4 million as a result of the adoption of SFAS No. 143 and EITF 02-3 in 2003, which had the effect of reducing net income in 2003 but were non-cash transactions. This decrease in non-cash adjustments to net income was offset in part by the following increases in non-cash adjustments in 2004:

- higher depreciation and amortization and accretion of asset retirement obligations of $61 million,
- the loss on sale of discontinued operations of $50 million,

a decrease in the net gain on sales of investments and other assets of $27 million primarily due to the sale of financial and real estate investments in 2003. We adjust net income to exclude these gains and reflect the proceeds from these sales in the investing activities sections, and

an increase in deferred income taxes of $14 million.

Changes in working capital had a negative impact of $319.6 million on cash flow from operations in 2004 compared to a negative impact of $50.0 million in 2003. The $269.6 million decrease in cash due to working capital changes was primarily due to the following uses of cash in 2004 compared to 2003:

a decline in working capital related to accrued taxes of approximately $254 million in 2004 compared to 2003 due to higher income tax payments in 2004 compared to refunds of taxes in 2003 and due to the timing of income tax accruals in 2004 compared to 2003,

a $48 million unfavorable change in working capital relating to our accounts receivable and accounts payable primarily due to increased volumes associated with our merchant energy business and the termination of an accounts receivable securitization program in 2004, and

an unfavorable change of approximately $61 million relating to fuel stocks during 2004 primarily due to higher gas and coal prices, which affected inventory levels at BGE and our merchant energy business.

These items were partially offset by a source of cash of approximately $90 million in 2004 compared to 2003 primarily due to other favorable working capital changes as a result of higher accrued expenses in 2004 compared to 2003.

Cash Flows from Investing Activities

Cash used in investing activities was $1,174.0 million in 2005 compared to $1,152.7 million in 2004. The slight increase in cash used in investing activities was mostly due to $336.2 million of cash paid for contract and portfolio acquisitions and $82.8 million in issuances of loans receivable related primarily to a customer contract restructuring. We discuss contract and portfolio acquisitions in more detail below, and the customer contract restructuring is discussed in more detail in *Note 4.* These increases in cash used in 2005 compared to 2004 were partially offset by less cash paid for asset acquisitions and business combinations of $220.1 million in 2005 compared to 2004 and an increase in cash proceeds from the sale of discontinued operations of $216.7 million, primarily due to the sale of Oleander and our other nonregulated international investments in 2005 as discussed in more detail in *Note 2*.

Cash used in investing activities in 2004 was about the same as in 2003 primarily due to the decrease in cash used for acquisitions and proceeds from the sale of discontinued operations in 2004, substantially offsetting increased spending on property, plant and equipment and a decrease in cash proceeds from the sale of investments and other assets in 2004 compared to 2003.

Cash Flows from Financing Activities

Cash provided by financing activities was $653.5 million in 2005 compared to $50.9 million in 2004. The increase in 2005 compared to 2004 was mostly due to an increase in proceeds from contract and portfolio acquisitions of $909.4 million. We discuss proceeds from contract and portfolio acquisitions in more detail below. This increase in cash provided by financing activities was partially offset by a reduction in proceeds from issuances of common stock, an increase in cash used for repayments of debt, and higher dividend payments in 2005 compared to 2004.

Cash provided by financing activities decreased $157.9 million in 2004 compared to 2003 mostly due to lower issuance of net debt in 2004 compared to 2003, partially offset by higher proceeds from common stock issuances.

Contract and Portfolio Acquisitions

During 2004 and 2005, our merchant energy business acquired several pre-existing energy purchase and sale agreements, which generated significant cash flows at the inception of the contracts. These agreements had contract prices that differed from market prices at closing, which resulted in cash payments from the counterparty at the acquisition of the contract. We received $117.5 million in 2004 and $690.7 million in 2005 for various contract and portfolio acquisitions. We reflect the underlying contracts on a gross basis as assets or liabilities in our Consolidated Balance Sheets depending on whether they were at above- or below-market prices at closing; therefore, we have also reflected them on a gross basis in cash flows from investing and financing activities in our Consolidated Statements of Cash Flows as follows:

Year ended December 31,	2005	2004
	(In millions)	
Financing activities proceeds from contract and portfolio acquisitions	**$ 1,026.9**	$ 117.5
Investing activities contract and portfolio acquisitions	**(336.2)**	
Cash flows from contract and portfolio acquisitions	**$ 690.7**	$ 117.5

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

We discuss certain of these contract and portfolio acquisitions in more detail in *Note 4* and *Note 5*.

Security Ratings

Independent credit-rating agencies rate Constellation Energy's and BGE's fixed-income securities. The ratings indicate the agencies' assessment of each company's ability to pay interest, distributions, dividends, and principal on these securities. These ratings affect how much it will cost each company to sell these securities. The better the rating, the lower the cost of the securities to each company when they sell them.

The factors that credit rating agencies consider in establishing Constellation Energy's and BGE's credit ratings include, but are not limited to, cash flows, liquidity, business risk profile, and the amount of debt as a component of total capitalization. At the date of this report, our credit ratings were as follows:

	Standard & Poors Rating Group	Moody's Investors Service	Fitch-Ratings
Constellation Energy			
Commercial Paper	A-2	P-2	F-2
Senior Unsecured Debt	BBB	Baa1	A-
BGE			
Commercial Paper	A-2	P-1	F-1
Mortgage Bonds	A	A1	A+
Senior Unsecured Debt	BBB+	A2	A
Trust Preferred Securities	BBB-	A3	A-
Preference Stock	BBB-	Baa1	A-

In December 2005, in conjunction with the announcement of the pending merger between Constellation Energy and FPL Group, Standard & Poors Rating Group and Moody's Investors Service reviewed our ratings and took the following actions:

- Moody's Investor Service revised Constellation Energy's rating outlook to positive from stable and maintained BGE's stable rating outlook, and
- Standard & Poor's Ratings Services placed the ratings on Constellation Energy and our subsidiaries on creditwatch with positive implications.

Fitch-Ratings outlook for Constellation Energy and BGE remains stable. We discuss the pending merger in more detail in *Note 15*.

Available Sources of Funding

We continuously monitor our liquidity requirements and believe that our credit facilities and access to the capital markets provide sufficient liquidity to meet our business requirements. We discuss our available sources of funding in more detail below.

Constellation Energy

In addition to our cash balance, we have a commercial paper program under which we can issue short-term notes to fund our subsidiaries. At December 31, 2005, we had approximately $3.6 billion of credit under several facilities. These facilities include:

- a $200 million 364-day bilateral line of credit that expires in December 2006,
- a $1.5 billion five-year revolving credit facility that expires in March 2010,
- a $1.1 billion five-year revolving credit facility that expires in November 2010, and
- a $750 million five-year revolving credit facility that expires in November 2010.

We enter into these facilities to ensure adequate liquidity to support our operations. Currently, we use the facilities to issue letters of credit primarily for our merchant energy business. Additionally, we can borrow directly from the banks or use the facilities to allow the issuance of commercial paper with the exception of the $200 million bilateral facility, which only supports letters of credit. We had $290.0 million of commercial paper outstanding at February 28, 2006.

These revolving credit facilities allow the issuance of letters of credit up to approximately $3.6 billion. At December 31, 2005, letters of credit that totaled $2.5 billion were issued under all of our facilities, which results in approximately $1.1 billion of unused credit facilities.

We expect to fund future acquisitions with an overall goal of maintaining a strong investment grade credit profile.

BGE

BGE maintains $200.0 million in annual committed credit facilities, expiring May 2006 through November 2006. BGE can borrow directly from the banks or use the facilities to allow commercial paper to be issued. As of December 31, 2005, BGE had no outstanding commercial paper, which results in $200.0 million in unused credit facilities.

Other Nonregulated Businesses

If we can get a reasonable value for our remaining real estate projects and other investments, additional cash may be obtained by selling them. Our ability to sell or liquidate assets will depend on market conditions, and we cannot give assurances that these sales or liquidations could be made.

Capital Resources

Our actual consolidated capital requirements for the years 2003 through 2005, along with the estimated annual amount for 2006, are shown in the table on the next page.

We will continue to have cash requirements for:

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

Capital requirements for 2006 and 2007 include estimates of spending for existing and anticipated projects. We continuously review and modify those estimates. Actual requirements may vary from the estimates included in the table on the next page because of a number of factors including:

- regulation, legislation, and competition,
- BGE load requirements,
- environmental protection standards,
- the type and number of projects selected for construction or acquisition,

the effect of market conditions on those projects,

the cost and availability of capital,

the availability of cash from operations, and

business decisions to invest in capital projects.

Our estimates are also subject to additional factors. Please see the *Forward Looking Statements* section.

	2003	2004	2005	2006
		(In millions)		
Nonregulated Capital Requirements:				
Merchant energy (excludes acquisitions)				
Generation plants	$ 175	$ 182	$ 182	$ 195
Nuclear fuel	59	133	130	140
Environmental controls	12		1	40
Portfolio acquisitions/investments	51	11	231	395
Technology/other	122	129	165	185
Total merchant energy capital requirements	419	455	709	955
Other nonregulated capital requirements	53	42	32	20
Total nonregulated capital requirements	472	497	741	975
Regulated Capital Requirements:				
Regulated electric	236	209	241	275
Regulated gas	53	56	50	95
Total regulated capital requirements	289	265	291	370
Total capital requirements	$ 761	$ 762	$ 1,032	$ 1,345

The table above does not include amounts related to pre-acquisition capital requirements but does include post-acquisition capital requirements. We discuss our acquisitions in more detail in Note 15.

As of the date of this report, we have not completed our 2007 capital budgeting process, but expect our 2007 capital requirements to be approximately $1,330 million.

Our environmental controls capital requirements are affected by new rules or regulations that require modifications to our facilities. Based on information currently available to us regarding recently issued regulations, we will install additional air emission control equipment at our coal-fired generating facilities in Maryland and at co-owned coal-fired generating facilities in Pennsylvania. We estimate another $400-$500 million of capital spending from 2008-2010. We discuss environmental matters in more detail in *Item 1. Business Environmental Matters*.

Capital Requirements

Merchant Energy Business

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

improvements to generating plants,

nuclear fuel costs,

upstream gas investments,

portfolio acquisitions and other investments,

costs of complying with the Environmental Protection Agency (EPA), Maryland, and Pennsylvania nitrogen oxides (NO_x) and sulfur dioxide (SO_2) emissions regulations, and

enhancements to our information technology infrastructure.

Regulated Electric and Gas

Regulated electric and gas construction expenditures primarily include new business construction needs and improvements to existing facilities, including projects to improve reliability. Capital requirements for 2003 in the table above include $32.0 million in costs incurred as a result of Hurricane Isabel to restore the electric distribution system.

Funding for Capital Requirements

Merchant Energy Business

Funding for the expansion of our merchant energy business is expected from internally generated funds. We also have available sources from commercial paper issuances, issuances of long-term debt and equity, leases, and other financing activities.

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

We expect to fund acquisitions with a mixture of debt and equity with an overall goal of maintaining a strong investment grade credit profile.

Regulated Electric and Gas

Funding for regulated electric and gas capital expenditures is expected from internally generated funds. During 2006, we expect our regulated business to generate sufficient cash flows from operations to meet BGE's operating requirements. If necessary, additional funding may be obtained from commercial paper issuances, available capacity under credit facilities, the issuance of long-term debt, trust preferred securities, or preference stock, and/or from time to time equity contributions from Constellation Energy. BGE also participates in a cash pool administered by Constellation Energy as discussed in *Note 16*.

Other Nonregulated Businesses

Funding for our other nonregulated businesses is expected from internally generated funds, commercial paper issuances, issuances of long-term debt of Constellation Energy, sales of securities and assets, and/or from time to time equity contributions from Constellation Energy.

Our ability to sell or liquidate securities and non-core assets will depend on market conditions, and we cannot give assurances that these sales or liquidations could be made. We discuss our remaining non-core assets and market conditions in the *Results of Operations Other Nonregulated Businesses* section.

Contractual Payment Obligations and Committed Amounts

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

Our total contractual payment obligations as of December 31, 2005, increased $2.1 billion compared to 2004 primarily due to an increase in fuel and transportation obligations. The increase in fuel and transportation obligations was mostly due to increased gas prices due to supply and demand imbalances and hurricane-related disruptions in the Gulf Coast and new contracts related to gas and nuclear fuel procurement. We detail our contractual payment obligations as of December 31, 2005 in the following table:

	Payments				
	2006	2007-2008	2009-2010	Thereafter	Total
			(In millions)		
Contractual Payment Obligations					
Long-term debt:[1]					
Nonregulated					
Principal	$ 21.7	$ 627.4	$ 501.4	$ 2,256.1	$ 3,406.6
Interest	213.7	358.8	309.4	1,647.6	2,529.5
Total	235.4	986.2	810.8	3,903.7	5,936.1
BGE					
Principal	444.6	416.8	11.5	589.1	1,462.0
Interest	83.9	97.5	71.2	775.1	1,027.7
Total	528.5	514.3	82.7	1,364.2	2,489.7
BGE preference stock				190.0	190.0
Operating leases[2]	159.6	262.6	93.8	325.5	841.5
Purchase obligations:[3]					
Purchased capacity and energy[4]	697.6	891.5	308.5	162.7	2,060.3
Fuel and transportation	2,360.3	1,054.6	436.2	575.5	4,426.6
Other	140.3	137.7	46.5	145.6	470.1
Other noncurrent liabilities:					
Postretirement and postemployment benefits[5]	33.2	76.7	83.9	188.8	382.6
Total contractual payment obligations	$ 4,154.9	$ 3,923.6	$ 1,862.4	$ 6,856.0	$ 16,796.9

1 *Amounts in long-term debt reflect the original maturity date. Investors may require us to repay $282.3 million early through put options and remarketing features. Interest on variable rate debt is included based on the December 31, 2005 forward curve for interest rates.*

2 *Our operating lease commitments include future payment obligations under certain power purchase agreements as discussed further in Note 11.*

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

4 *Our contractual obligations for purchased capacity and energy are shown on a gross basis for certain transactions, including both the fixed payment portions of tolling contracts and estimated variable payments under unit-contingent power purchase agreements. We have recorded $3.0 million of liabilities related to purchased capacity and energy obligations at December 31, 2005 in our Consolidated Balance Sheets.*

5 *Amounts related to postretirement and postemployment benefits are for unfunded plans and reflect present value amounts consistent with the determination of the related liabilities recorded in our Consolidated Balance Sheets as discussed in Note 7.*

The table below presents our contingent obligations. Our contingent obligations increased $4.4 billion during 2005, primarily due to the issuance of additional letters of credit and guarantees by the parent company for subsidiary obligations to third parties in support of the growth of our merchant energy business. These amounts do not represent incremental consolidated Constellation Energy obligations; rather, they primarily represent parental guarantees of certain subsidiary obligations to third parties. Our calculation of the fair value of subsidiary obligations covered by the $8,268.5 million of parent company guarantees was $2,830.5 million at December 31, 2005. Accordingly, if the parent company was required to fund subsidiary obligations, the total amount based on December 31, 2005 market prices is $2,830.5 million.

	Expiration				
	2006	2007-2008	2009-2010	Thereafter	Total
	(In millions)				
Contingent Obligations					
Letters of credit	$ 2,477.5	$ 8.6	$	$	$ 2,486.1
Guarantees competitive supply[1]	5,514.1	546.1	251.6	1,956.7	8,268.5
Other guarantees, net[2]	5.6	13.3	1.8	1,237.0	1,257.7
Total contingent obligations	$ 7,997.2	$ 568.0	$ 253.4	$ 3,193.7	$ 12,012.3

1 *While the face amount of these guarantees is $8,268.5 million, we would not expect to fund the full amount. In the event the parent were required to fulfill subsidiary obligations, our calculation of the fair value of obligations covered by these guarantees was $2,830.5 million at December 31, 2005.*

2 *Other guarantees in the above table are shown net of liabilities of $25.0 million recorded at December 31, 2005 in our Consolidated Balance Sheets.*

Pending Merger with FPL Group, Inc.

In connection with the merger agreement with FPL Group, there are certain contingencies relating to termination fees. We discuss these contingencies in *Note 15*. In addition, as a result of the change in control provisions in our long-term incentive plans, we will be required to pay cash of approximately $130 million (based on estimated fair value of outstanding awards at December 31, 2005) to settle certain stock-based compensation awards if we complete our pending merger with FPL Group. We discuss our long-term incentive plans in more detail in *Note 14*.

Liquidity Provisions

In many cases, customers of our merchant energy business rely on the creditworthiness of Constellation Energy. A decline below investment grade by Constellation Energy would negatively impact the business prospects of that operation.

We regularly review our liquidity needs to ensure that we have adequate facilities available to meet collateral requirements. This includes having liquidity available to meet margin requirements for our wholesale marketing and risk management operation and our retail competitive supply activities.

We have certain agreements that contain provisions that would require additional collateral upon credit rating decreases in the senior unsecured debt of Constellation Energy. Decreases in Constellation Energy's credit ratings would not trigger an early payment on any of our credit facilities.

Under counterparty contracts related to our wholesale marketing and risk management operation, we are obligated to post collateral if Constellation Energy's senior unsecured credit ratings declined below established contractual levels. Based on contractual provisions at December 31, 2005, we estimate that if Constellation Energy's senior unsecured debt were downgraded we would have the following additional collateral obligations:

Credit Ratings Downgraded to	Incremental Obligations	Cumulative Obligations
	(In millions)	
BBB-/Baa3	$ 361	$ 361
Below investment grade	1,286	1,647

Based on market conditions and contractual obligations at the time of a downgrade, we could be required to post collateral in an amount that could exceed the amounts specified above, which could be material. We assess the risk of being downgraded to below investment grade as remote. However, we actively monitor our collateral obligations and liquidity. We discuss our credit facilities in the *Available Sources of Funding* section.

The credit facilities of Constellation Energy and BGE have limited material adverse change clauses that only consider a material change in financial condition and are not directly affected by decreases in credit ratings. If these clauses are invoked, the lending institutions can decline to make new advances or issue new letters of credit, but cannot accelerate the payment of existing amounts outstanding. The long-term debt indentures of Constellation Energy and BGE do not contain material adverse change clauses or financial covenants.

Certain credit facilities of Constellation Energy contain a provision requiring Constellation Energy to maintain a ratio of debt to capitalization equal to or less than 65%. At December 31, 2005, the debt to capitalization ratios as defined in the credit agreements were no greater than 59%. Certain credit agreements of BGE contain provisions requiring BGE to maintain a ratio of debt to capitalization equal to or less than 65%. At December 31, 2005, the debt to capitalization ratio for BGE as defined in these credit agreements was 45%. At December 31, 2005, no amount was outstanding under these agreements.

Failure by Constellation Energy, or BGE, to comply with these provisions could result in the acceleration of the maturity of the debt outstanding under these facilities. The credit facilities of Constellation Energy contain usual and customary cross-default provisions that apply to defaults on debt by Constellation Energy and certain subsidiaries over a specified threshold. Certain BGE credit facilities also contain usual and customary cross-default provisions that apply to defaults on debt by BGE over a specified threshold. The indentures pursuant to which BGE has issued and outstanding mortgage bonds and subordinated debentures provide that a default under any debt instrument issued under the relevant indenture may cause a default of all debt outstanding under such indenture.

Constellation Energy also provides credit support to Calvert Cliffs, Nine Mile Point, and Ginna to ensure these plants have funds to meet expenses and obligations to safely operate and maintain the plants.

As discussed in the *Regulation by the Maryland PSC* section, the Maryland PSC and the Maryland General Assembly are considering proposals to defer recovery of costs to be incurred by BGE to provide residential POLR service beginning July 2006. Any decision to defer or limit recovery of such costs could have a material impact on our, or BGE's, liquidity.

We discuss our short-term credit facilities in *Note 8*, long-term debt in *Note 9*, lease requirements in *Note 11*, and commitments and guarantees in *Note 12*.

Off-Balance Sheet Arrangements

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

We use these arrangements when they enable us to obtain financing or execute commercial transactions on favorable terms. As of December 31, 2005, we have no material off-balance sheet arrangements including:

- guarantees with third-parties that are subject to the initial recognition and measurement requirements of FASB Interpretation No. 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness to Others*,
- retained interests in assets transferred to unconsolidated entities,

derivative instruments indexed to our common stock, and classified as equity, or

variable interests in unconsolidated entities that provide financing, liquidity, market risk or credit risk support, or engage in leasing, hedging or research and development services.

We discuss our guarantees in *Note 12* and our significant variable interests in *Note 4*.

Market Risk

We are exposed to various risks, including, but not limited to, energy commodity price and volatility risk, credit risk, interest rate risk, equity price risk, foreign exchange risk, and operations risk. Our risk management program is based on established policies and procedures to manage these key business risks with a strong focus on the physical nature of our business. This program is predicated on a strong risk management culture combined with an effective system of internal controls.

The Audit Committee of the Board of Directors periodically reviews compliance with our risk parameters, limits and trading guidelines and our Board of Directors has established a value at risk limit. We have a Risk Management Division that is responsible for monitoring the key business risks, enforcing compliance with risk management policies and risk limits, as well as managing credit risk. The Risk Management Division reports to the Chief Risk Officer (CRO) who provides regular risk management updates to the Audit Committee and the Board of Directors.

We have a Risk Management Committee (RMC) that is responsible for establishing risk management policies, reviewing procedures for the identification, assessment, measurement and management of risks, and the monitoring and reporting of risk exposures. The RMC meets on a regular basis and is chaired by the Vice Chairman of Constellation Energy & Chairman of Constellation Energy Commodities Group, and consists of our Chief Executive Officer, our Chief Financial Officer and Chief Administrative Officer, our Executive Vice President of Corporate Strategy and Retail Competitive Supply, the Co-Presidents & Chief Executive Officers of Constellation Energy Commodities Group, the President of Constellation Generation Group and the Chief Risk Officer. In addition, the CRO coordinates with the risk management committees at the major operating subsidiaries that meet regularly to identify, assess, and quantify material risk issues and to develop strategies to manage these risks.

Interest Rate Risk

We are exposed to changes in interest rates as a result of financing through our issuance of variable-rate and fixed-rate debt and certain related interest rate swaps. We may use derivative instruments to manage our interest rate risks.

In July 2004, to optimize the mix of fixed and floating-rate debt, we entered into interest rate swaps relating to $450 million of our long-term debt. These fair value hedges effectively convert our current fixed-rate debt to a floating-rate instrument tied to the three month London Inter-Bank Offered Rate. Including the $450 million in interest rate swaps, approximately 14% of our long-term debt is floating-rate.

The following table provides information about our debt obligations that are sensitive to interest rate changes:

Principal Payments and Interest Rate Detail by Contractual Maturity Date

	2006	2007	2008	2009	2010	Thereafter	Total	Fair value at December 31, 2005
				(Dollars in millions)				
Long-term debt								
Variable-rate debt	$ 97.4	$	$	$	$	$ 601.9	$ 699.3	$ 699.3
Average interest rate	4.41%	%	%	%	%	5.76%	5.57%	
Fixed-rate debt	$ 368.9(A)	$ 743.3	$ 300.9	$ 512.9	$	$ 2,243.3	$ 4,169.3	$ 4,379.3
Average interest rate	5.41%	6.47%	6.30%	6.13%	%	6.38%	6.37%	

(A)
Amount excludes $282.3 million of long-term debt that contains certain put options under which lenders could potentially require us to repay the debt prior to maturity of which $25.0 million is classified as current portion of long-term debt in our Consolidated Balance Sheets and in our Consolidated Statements of Capitalization.

Commodity Risk

We are exposed to the impact of market fluctuations in the price and transportation costs of electricity, natural gas, coal, and other commodities. These risks arise from our ownership and operation of power plants, the load-serving activities of BGE and our competitive supply operations, and our origination and risk management activities. We discuss these risks separately for our merchant energy and our regulated businesses below.

Merchant Energy Business

Our merchant energy business is exposed to various risks in the competitive marketplace that may materially impact its financial results and affect our earnings. These risks include changes in commodity prices, imbalances in supply and demand, and operations risk.

<u>*Commodity Prices*</u>

Commodity price risk arises from:

- the potential for changes in the price of, and transportation costs for, electricity, natural gas, coal, and other commodities,
- the volatility of commodity prices, and
- changes in interest rates and foreign exchange rates.

A number of factors associated with the structure and operation of the energy markets significantly influence the level and volatility of prices for energy commodities and related derivative products. We use such commodities and contracts in our merchant energy business, and if we do not properly hedge the associated financial exposure, this commodity price volatility could affect our earnings. These factors include:

- seasonal, daily, and hourly changes in demand,
- extreme peak demands due to weather conditions,
- available supply resources,
- transportation availability and reliability within and between regions,
- location of our generating facilities relative to the location of our load-serving obligations,
- procedures used to maintain the integrity of the physical electricity system during extreme conditions,
- changes in the nature and extent of federal and state regulations, and
- geopolitical concerns affecting global supply of oil and natural gas.

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

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

Additionally, we have fuel requirements that are subject to future changes in coal, natural gas, and oil prices. Our power generation facilities purchase fuel under contracts or in the spot market. Fuel prices may be volatile and the price that can be obtained from power sales may not change at the same rate or in the same direction as changes in fuel costs. This could have a material adverse impact on our financial results.

Supply and Demand Risk

We are exposed to the risk that available sources of supply may differ from the amount of power demanded by our customers under fixed-price load-serving contracts. During periods of high demand, our power supplies may be insufficient to serve our customers' needs and could require us to purchase additional energy at higher prices. Alternatively, during periods of low demand, our power supplies may exceed our customers' needs and could result in us selling that excess energy at lower prices. Either of those circumstances could have a negative impact on our financial results.

We are also exposed to variations in the prices and required volumes of natural gas and coal we burn at our power plants to generate electricity. During periods of high demand on our generation assets, our fuel supplies may be insufficient and could require us to procure additional fuel at higher prices. Alternatively, during periods of low demand on our generation assets, our fuel supplies may exceed our needs, and could result in us selling the excess fuels at lower prices. Either of these circumstances will have a negative impact on our financial results.

Operations Risk

Operations risk is the risk that a generating plant will not be available to produce energy and the risks related to physical delivery of energy to meet our customers' needs. If one or more of our generating facilities is not able to produce electricity when required due to operational factors, we may have to forego sales opportunities or fulfill fixed-price sales commitments through the operation of other more costly generating facilities or through the purchase of energy in the wholesale market at higher prices. We purchase power from generating facilities we do not own. If one or more of those generating facilities were unable to produce electricity due to operational factors, we may be forced to purchase electricity in the wholesale market at higher prices. This could have a material adverse impact on our financial results.

Our nuclear plants produce electricity at a relatively low marginal cost. The Nine Mile Point and Ginna facilities each sells 90% of output under unit-contingent power purchase agreements (we have no obligation to provide power if the units are not available) to the previous owners. However, if an unplanned outage were to occur at Calvert Cliffs during periods when demand was high, we may have to purchase replacement power at potentially higher prices to meet our obligations, which could have a material adverse impact on our financial results.

Risk Management

As part of our overall portfolio, we manage the commodity price risk of our competitive supply activities and our electric generation facilities, including power sales, fuel and energy purchases, emission credits, interest rate and foreign currency risks, weather risk, and the market risk of outages. In order to manage these risks, we may enter into fixed-price derivative or non-derivative contracts to hedge the variability in future cash flows from forecasted sales and purchases of energy, including:

- forward contracts, which commit us to purchase or sell energy commodities in the future;
- futures contracts, which are exchange-traded standardized commitments to purchase or sell a commodity or financial instrument, or to make a cash settlement, at a specific price and future date;
- swap agreements, which require payments to or from counterparties based upon the differential between two prices for a predetermined contractual (notional) quantity; and
- option contracts, which convey the right to buy or sell a commodity, financial instrument, or index at a predetermined price.

The objectives for entering into such hedges include:

- fixing the price for a portion of anticipated future electricity sales at a level that provides an acceptable return on our electric generation operations,
- fixing the price of a portion of anticipated fuel purchases for the operation of our power plants,
- fixing the price for a portion of anticipated energy purchases to supply our load-serving customers, and
- managing our exposure to interest rate risk and foreign currency exchange risks.

The portion of forecasted transactions hedged may vary based upon management's assessment of market, weather, operational, and other factors.

While some of the contracts we use to manage risk represent commodities or instruments for which prices are available from external sources, other commodities and certain contracts are not actively traded and are valued using other pricing sources and modeling techniques to determine expected future market prices, contract quantities, or both. We use our best estimates to determine the fair value of commodity and derivative contracts we hold and sell. These estimates consider various factors including closing exchange and over-the-counter price quotations, time value, volatility factors, and credit exposure. However, it is likely that future market prices could vary from those used in recording mark-to-market energy assets and liabilities, and such variations could be material.

We measure the sensitivity of our wholesale marketing and risk management mark-to-market energy contracts to potential changes in market prices using value at risk. Value at risk is a statistical model that attempts to predict risk of loss based on historical market price volatility. We calculate value at risk using a historical variance/covariance technique that models option positions using a linear approximation of their value. Additionally, we estimate variances and correlation using historical commodity price changes over the most recent rolling three-month period. Our value at risk calculation includes all wholesale marketing and risk management mark-to-market energy assets and liabilities, including contracts for energy commodities and derivatives that result in physical settlement and contracts that require cash settlement.

The value at risk calculation does not include market risks associated with activities that are subject to accrual accounting, primarily our generating facilities and our competitive supply load-serving activities. We manage these risks by monitoring our fuel and energy purchase requirements and our estimated contract sales volumes compared to associated supply arrangements. We also engage in hedging activities to manage these risks. We describe those risks and our hedging activities earlier in this section.

The value at risk amounts below represent the potential pre-tax loss in the fair value of our wholesale marketing and risk management mark-to-market energy assets and liabilities over one and ten-day holding periods.

Total Wholesale Value at Risk

For the year ended December 31,	**2005**	**2004**
	(In millions)	
99% Confidence Level, One-Day Holding Period		
Year end	**$ 10.0**	$ 4.4
Average	**6.1**	3.7
High	**14.5**	7.8
Low	**2.4**	2.5
95% Confidence Level, One-Day Holding Period		
Year end	**$ 7.6**	$ 3.4
Average	**4.7**	2.8
High	**11.0**	5.9
Low	**1.8**	1.9
95% Confidence Level, Ten-Day Holding Period		
Year end	**$ 24.1**	$ 10.7
Average	**14.7**	9.0
High	**34.9**	18.7
Low	**5.8**	6.1

Based on a 99% confidence interval, we would expect a one-day change in the fair value of the portfolio greater than or equal to the daily value at risk approximately once in every 100 days. In 2005, we experienced one instance where the actual daily mark-to-market change in portfolio value exceeded the predicted value at risk. On average, we expect to experience a change in value to our portfolio greater than our value at risk approximately three times in a calendar year. However, published market studies conclude that exceeding daily value at risk less than seven times in a one-year period is considered consistent with a 99% confidence interval.

The table above is the value at risk associated with our wholesale marketing and risk management operation's mark-to-market energy assets and liabilities, including both trading and non-trading activities. We experienced higher value at risk for the year ended December 31, 2005 compared to the year ended December 31, 2004, primarily due to higher commodity prices.

The following table details our value at risk for the trading portion of our wholesale marketing and risk management mark-to-market energy assets and liabilities over a one-day holding period at a 99% confidence level for 2005 and 2004:

Wholesale Trading Value at Risk

For the year ended December 31,	**2005**	**2004**
	(In millions)	
Average	**$ 5.5**	$ 2.6
High	**13.3**	6.9

We experienced higher value at risk for the year ended December 31, 2005 compared to the year ended December 31, 2004, for the trading portion of our wholesale trading portfolio due to increased commodity prices, volatility, and trading activity. Our trading positions can be used to manage the commodity price risk of our competitive supply activities and our generation facilities. We also engage in trading activities for profit. These activities are managed through daily value at risk and stop loss limits and liquidity guidelines.

Due to the inherent limitations of statistical measures such as value at risk and the seasonality of changes in market prices, the value at risk calculation may not reflect the full extent of our commodity price risk exposure. Additionally, actual changes in the value of options may differ from the value at risk calculated using a linear approximation inherent in our calculation method. As a result, actual changes in the fair value of mark-to-market energy assets and liabilities could differ from the calculated value at risk, and such changes could have a material impact on our financial results.

Regulated Electric Business

BGE's residential base rates are frozen for a six-year period ending June 30, 2006, and its commercial and industrial base rates were frozen for a four-year period that ended June 30, 2004. The commodity and transmission components of rates are frozen for different time periods depending on the customer type and service options selected by customers.

Our wholesale marketing and risk management operation provides BGE 100% of the energy and capacity to meet its residential standard offer service obligations through June 30, 2006. Bidding to supply BGE's standard offer service to commercial and industrial customers, and to residential customers beyond June 30, 2006, will occur from time to time through a competitive bidding process approved by the Maryland PSC. Our wholesale marketing and risk management operation is supplying a portion of BGE's standard offer service obligation to commercial and industrial customers. We discuss standard offer service and the impact on base rates in more detail in *Item 1. Business Electric Business* section.

BGE may receive performance assurance collateral from suppliers to mitigate suppliers' credit risks in certain circumstances. Performance assurance collateral is designed to protect BGE's potential exposure over the term of the supply contracts and will fluctuate to reflect changes in market prices. In addition to the collateral provisions, there are supplier "step-up" provisions, where other suppliers can step in if the early termination of a Full-Requirements Service Agreement with a supplier should occur, as well as specific mechanisms for BGE to otherwise replace defaulted supplier contracts. All costs incurred by BGE to replace the supply contract are to be recovered from the defaulting supplier or from customers through rates. Finally, BGE's exposure to uncollectible expense or credit risk from customers for the commodity portion of the bill is covered by the administrative fee included in Provider of Last Resort rates.

Regulated Gas Business

Our regulated gas business may enter into gas futures, options, and swaps to hedge its price risk under our market-based rate incentive mechanism and our off-system gas sales program. We discuss this further in *Note 13*. At December 31, 2005 and 2004, our exposure to commodity price risk for our regulated gas business was not material.

Credit Risk

We are exposed to credit risk, primarily through our merchant energy business. Credit risk is the loss that may result from counterparties' nonperformance. We evaluate the credit risk of our wholesale marketing and risk management operation and our retail competitive supply activities separately as discussed below.

Wholesale Credit Risk

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

As of December 31, 2005 and 2004, the credit portfolio of our wholesale marketing and risk management operation had the following public credit ratings:

At December 31,	**2005**	**2004**
Rating		
Investment Grade[1]	**53%**	62%
Non-Investment Grade	**7**	15
Not Rated	**40**	23

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

Our exposure to unrated counterparties was $1.4 billion at December 31, 2005 compared to $328 million at December 31, 2004. This increase was mostly due to the growth in our merchant energy business, particularly with natural gas and international coal customers that do not have public credit ratings. Although not rated, a majority of these counterparties are considered investment grade equivalent based on our internal credit ratings. We utilize internal credit ratings to evaluate the creditworthiness of our wholesale customers, including those companies that do not have public credit ratings. Based on internal credit ratings, approximately $916 million or 68% of the exposure to unrated counterparties was rated investment grade equivalent at December 31, 2005 and approximately $173 million or 53% was rated investment grade equivalent at December 31, 2004. The following table provides the breakdown of the credit quality of our wholesale credit portfolio based on our internal credit ratings.

At December 31,	**2005**	**2004**
Investment Grade Equivalent	**80%**	74%
Non-Investment Grade	**20**	26

A portion of our total wholesale credit risk is related to transactions that are recorded in our Consolidated Balance Sheets. These transactions primarily consist of open positions from our wholesale marketing and risk management operation that are accounted for using mark-to-market accounting, as well as amounts owed by wholesale counterparties for transactions that settled but have not yet been paid. The following table highlights the credit quality and exposures related to these activities:

Rating	Total Exposure Before Credit Collateral	Credit Collateral	Net Exposure	Number of Counterparties Greater than 10% of Net Exposure	Net Exposure of Counterparties Greater than 10% of Net Exposure
			(Dollars in millions)		
Investment grade	$ 1,465	$ 197	$ 1,268	1	$ 247
Split rating	39	15	24		
Non-investment grade	242	79	163		
Internally rated investment grade	616	4	612		
Internally rated non-investment grade	209	13	196		
Total	$ 2,571	$ 308	$ 2,263	1	$ 247

Our net exposure to investment grade counterparties and internally rated investment grade counterparties increased $977 million compared to December 31, 2004 primarily as a result of higher commodity prices.

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

Additionally, 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 mark-to-market contracts, the amount owed for settled transactions, and additional payments, if any, that we would have to make to settle unrealized losses on accrual contracts.

Retail Credit Risk

We are exposed to retail credit risk through our competitive electricity and natural gas supply activities which serve commercial and industrial companies. Retail credit risk results when customers default on their contractual obligations. This risk represents the loss that may be incurred due to the nonpayment of a customer's accounts receivable balance, as well as the loss from the resale of energy previously committed to serve the customer.

Retail credit risk is managed through established credit policies, monitoring customer exposures, and the use of credit mitigation measures such as letters of credit or prepayment arrangements.

Our retail credit portfolio is well diversified with no significant company or industry concentrations. During 2005, we did not experience a material change in the credit quality of our retail credit portfolio compared to 2004. Retail credit quality is dependent on the economy and the ability of our customers to manage through unfavorable economic cycles and other market changes. If the business environment were to be negatively affected by changes in economic or other market conditions, our retail credit risk may be adversely impacted.

Foreign Currency Risk

Our merchant energy business is exposed to the impact of foreign exchange rate fluctuations. This foreign currency risk arises from our activities in countries where we transact in currencies other than the U.S. dollar. In 2005, our exposure to foreign currency risk was not material. However, we expect our foreign currency exposure to grow due to our Canadian presence and international coal operations. We manage our exposure to foreign currency exchange rate risk using a comprehensive foreign currency hedging program. While we cannot predict currency fluctuations, the impact of foreign currency exchange rate risk could be material.

Equity Price Risk

We are exposed to price fluctuations in equity markets primarily through our pension plan assets, our nuclear decommissioning trust funds, and trust assets securing certain executive benefits. We are required by the NRC to maintain externally funded trusts for the costs of decommissioning our nuclear power plants. We discuss our nuclear decommissioning trust funds in more detail in *Note 1*.

A hypothetical 10% decrease in equity prices would result in an approximate $115 million reduction in the fair value of our financial investments that are classified as trading or available-for-sale securities. In 2005, our actual return on pension plan assets was $76 million due to advances in the markets in which plan assets are invested. We describe our financial investments in more detail in *Note 4*, and our pension plans in *Note 7*.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

The information required by this item with respect to market risk is set forth in *Item 7* of Part II of this Form 10-K under the heading *Market Risk*.

Item 8. Financial Statements and Supplementary Data

REPORT OF MANAGEMENT

Financial Statements

The management of Constellation Energy Group, Inc. and Baltimore Gas and Electric Company (the "Companies") is responsible for the information and representations in the Companies' financial statements. The Companies prepare the financial statements in accordance with accounting principles generally accepted in the United States of America based upon available facts and circumstances and management's best estimates and judgments of known conditions.

PricewaterhouseCoopers LLP, an independent registered public accounting firm, has audited the financial statements and expressed their opinion on them. They performed their audit in accordance with the standards of the Public Company Accounting Oversight Board (United States).

The Audit Committee of the Board of Directors, which consists of three independent Directors, meets periodically with management, internal auditors, and PricewaterhouseCoopers LLP to review the activities of each in discharging their responsibilities. The internal audit staff and PricewaterhouseCoopers LLP have free access to the Audit Committee.

Management's Report on Internal Control Over Financial Reporting

The management of Constellation Energy Group, Inc. ("Constellation Energy"), under the direction of its principal executive officer and principal financial officer, is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Exchange Act Rule 13a-15(f).

Constellation Energy's system of internal control over financial reporting is designed to provide reasonable assurance to Constellation Energy's management and Board of Directors regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles in the United States of America.

The management of Constellation Energy conducted an evaluation of the effectiveness of Constellation Energy's internal control over financial reporting using the framework in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). As noted in the COSO framework, an internal control system, no matter how well conceived and operated, can provide only reasonable-not absolute-assurance to management and the Board of Directors regarding achievement of an entity's financial reporting objectives. Based upon the evaluation under this framework, management concluded that Constellation Energy's internal control over financial reporting was effective as of December 31, 2005.

PricewaterhouseCoopers LLP, an independent registered public accounting firm, has audited management's assessment of the effectiveness of Constellation Energy's internal control over financial reporting at December 31, 2005, as stated in their report set forth below.

As discussed in *Item 9A. Controls and Procedures*, the management of Baltimore Gas & Electric Company ("BGE") has not assessed the effectiveness of BGE's internal control over financial reporting on a standalone basis because it is not yet required to do so by applicable federal securities laws and regulations.

Mayo A. Shattuck III	E. Follin Smith
Chairman of the Board, President and Chief Executive Officer	*Executive Vice-President, Chief Financial Officer, and Chief Administrative Officer*

REPORTS OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of Constellation Energy Group, Inc.

We have completed integrated audits of Constellation Energy Group, Inc. and Subsidiaries' 2005 and 2004 consolidated financial statements and of its internal control over financial reporting as of December 31, 2005, and an audit of its 2003 consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions on Constellation Energy Group Inc.'s 2005, 2004, and 2003 consolidated financial statements and on its internal control over financial reporting as of December 31, 2005, based on our audits, are presented below.

Consolidated financial statements and financial statement schedule

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a) 1 present fairly, in all material respects, the financial position of Constellation Energy Group, Inc. and Subsidiaries (the Company) at December 31, 2005 and 2004, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2005 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a) 2 presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in *Note 1* to the consolidated financial statements, in 2005 the Company changed its method of accounting for conditional asset retirement obligations and the accounting for stock based compensation. As discussed in *Note 1* to the consolidated financial statements, in 2003 the Company changed its method of accounting for asset retirement obligations and the accounting for certain energy contracts.

We have also previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets and statements of capitalization of Constellation Energy Group, Inc. and Subsidiaries as of December 31, 2003, 2002 and 2001, and the related consolidated statements of income, cash flows, and common shareholders' equity and comprehensive income for the years ended December 31, 2002 and 2001 (none of which are presented herein); and we expressed unqualified opinions on those consolidated financial statements. In our opinion, the information set forth in the Summary of Operations and Summary of Financial Condition of Constellation Energy Group, Inc. and Subsidiaries included in the Selected Financial Data for each of the five years in the period ended December 31, 2005, is fairly stated, in all material respects, in relation to the consolidated financial statements from which it has been derived.

Internal control over financial reporting

Also, in our opinion, management's assessment, included in Management's Report on Internal Control Over Financial Reporting appearing under Item 8, that the Company maintained effective internal control over financial reporting as of December 31, 2005, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2005, based on criteria established in *Internal Control Integrated Framework* issued by the COSO. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PricewaterhouseCoopers LLP
Baltimore, Maryland
March 1, 2006

To Board of Directors and Shareholder of Baltimore Gas and Electric Company

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a) 1 present fairly, in all material respects, the financial position of Baltimore Gas and Electric Company and Subsidiaries (the Company) at December 31, 2005 and 2004, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2005 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a) 2 presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits.

We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in *Note 1* to the consolidated financial statements, in 2003 the Company changed its method of accounting for asset retirement obligations.

We have also previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Baltimore Gas and Electric Company and Subsidiaries as of December 31, 2003, 2002 and 2001, and the related consolidated statements of income, cash flows, and comprehensive income for the years ended December 31, 2002 and 2001 (none of which are presented herein); and we expressed unqualified opinions on those consolidated financial statements. In our opinion, the information set forth in the Summary of Operations and Summary of Financial Condition of Baltimore Gas and Electric Company and Subsidiaries included in the Selected Financial Data for each of the five years in the period ended December 31, 2005, is fairly stated, in all material respects, in relation to the consolidated financial statements from which it has been derived.

PricewaterhouseCoopers LLP
Baltimore, Maryland
March 1, 2006

CONSOLIDATED STATEMENTS OF INCOME

Constellation Energy Group, Inc. and Subsidiaries

Year Ended December 31,	**2005**	2004	2003
	(In millions, except per share amounts)		
Revenues			
Nonregulated revenues	**$ 14,133.8**	$ 9,563.7	$ 6,819.9
Regulated electric revenues	**2,036.5**	1,967.6	1,921.5
Regulated gas revenues	**961.7**	755.1	712.7
Total revenues	**17,132.0**	12,286.4	9,454.1
Expenses			
Fuel and purchased energy expenses	**13,246.7**	8,699.9	6,142.3
Operating expenses	**1,918.9**	1,736.8	1,542.7
Merger-related transaction costs	**17.0**		
Workforce reduction costs	**4.4**	9.7	2.1
Depreciation, depletion, and amortization	**542.2**	505.7	453.9
Accretion of asset retirement obligations	**62.1**	53.2	42.7
Taxes other than income taxes	**282.6**	255.9	247.3
Total expenses	**16,073.9**	11,261.2	8,431.0
Income from Operations	**1,058.1**	1,025.2	1,023.1
Other Income	**62.8**	25.3	20.7
Fixed Charges			
Interest expense	**306.9**	324.4	336.6
Interest capitalized and allowance for borrowed funds used during construction	**(10.0)**	(10.8)	(13.3)
BGE preference stock dividends	**13.2**	13.2	13.2
Total fixed charges	**310.1**	326.8	336.5
Income from Continuing Operations Before Income Taxes	**810.8**	723.7	707.3
Income Tax Expense	**204.1**	156.9	250.6
Income from Continuing Operations and Before Cumulative Effects of Changes in Accounting Principles	**606.7**	566.8	456.7
Income (loss) from discontinued operations, net of income taxes of $21.4, $(11.2), $18.9, respectively	**23.6**	(27.1)	19.0
Cumulative effects of changes in accounting principles, net of income taxes of $(4.7) and $(119.5), respectively	**(7.2)**		(198.4)
Net Income	**$ 623.1**	$ 539.7	$ 277.3
Earnings Applicable to Common Stock	**$ 623.1**	$ 539.7	$ 277.3
Average Shares of Common Stock Outstanding Basic	**177.5**	172.1	166.3
Average Shares of Common Stock Outstanding Diluted	**179.7**	173.1	166.7

Year Ended December 31,	2005	2004	2003
Earnings Per Common Share from Continuing Operations and Before Cumulative Effects of Changes in Accounting Principles Basic	**$ 3.42**	$ 3.30	$ 2.75
Income (loss) from discontinued operations	**0.13**	(0.16)	0.11
Cumulative effects of changes in accounting principles	**(0.04)**		(1.19)
Earnings Per Common Share Basic	**$ 3.51**	$ 3.14	$ 1.67
Earnings Per Common Share from Continuing Operations and Before Cumulative Effects of Changes in Accounting Principles Diluted	**$ 3.38**	$ 3.28	$ 2.74
Income (loss) from discontinued operations	**0.13**	(0.16)	0.11
Cumulative effects of changes in accounting principles	**(0.04)**		(1.19)
Earnings Per Common Share Diluted	**$ 3.47**	$ 3.12	$ 1.66
Dividends Declared Per Common Share	**$ 1.34**	$ 1.14	$ 1.04

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

CONSOLIDATED BALANCE SHEETS

Constellation Energy Group, Inc. and Subsidiaries

At December 31,	**2005**	2004
	(In millions)	
Assets		
Current Assets		
Cash and cash equivalents	**$ 813.0**	$ 706.3
Accounts receivable (net of allowance for uncollectibles of **$47.4** and $43.1, respectively)	**2,727.9**	1,979.3
Fuel stocks	**489.5**	298.3
Materials and supplies	**197.0**	203.8
Mark-to-market energy assets	**1,339.2**	567.3
Risk management assets	**1,244.3**	471.5
Unamortized energy contract assets	**55.6**	37.2
Other	**555.3**	225.7
Total current assets	**7,421.8**	4,489.4
Investments and Other Assets		
Nuclear decommissioning trust funds	**1,110.7**	1,033.7
Investments in qualifying facilities and power projects	**306.2**	318.4
Regulatory assets (net)	**154.3**	195.4
Goodwill	**147.1**	144.8
Mark-to-market energy assets	**1,089.3**	359.8
Risk management assets	**626.0**	306.2
Unamortized energy contract assets	**141.2**	80.1
Other	**410.6**	332.7
Total investments and other assets	**3,985.4**	2,771.1
Property, Plant and Equipment		
Nonregulated property, plant and equipment	**8,580.8**	8,638.4
Regulated property, plant and equipment		
Plant in service	**5,423.8**	5,324.4
Construction work in progress	**93.9**	83.1
Plant held for future use	**2.8**	5.2
Total regulated property, plant and equipment	**5,520.5**	5,412.7
Nuclear fuel (net of amortization)	**302.0**	264.3
Accumulated depreciation	**(4,336.6)**	(4,228.8)
Net property, plant and equipment	**10,066.7**	10,086.6
Total Assets	**$ 21,473.9**	$ 17,347.1

See Notes to Consolidated Financial Statements.

At December 31,	**2005**	**2004**
Certain prior-year amounts have been reclassified to conform with the current year's presentation.		

CONSOLIDATED BALANCE SHEETS

Constellation Energy Group, Inc. and Subsidiaries

At December 31,	**2005**	2004
	(In millions)	
Liabilities and Equity		
Current Liabilities		
Short-term borrowings	**$ 0.7**	$
Current portion of long-term debt	**491.3**	480.4
Accounts payable and accrued liabilities	**1,667.9**	1,424.9
Customer deposits and collateral	**458.9**	223.8
Mark-to-market energy liabilities	**1,348.7**	559.7
Risk management liabilities	**483.5**	304.3
Unamortized energy contract liabilities	**489.5**	67.2
Deferred income taxes	**151.4**	95.0
Accrued expenses and other	**780.4**	507.1
Total current liabilities	**5,872.3**	3,662.4
Deferred Credits and Other Liabilities		
Deferred income taxes	**1,180.8**	1,303.3
Asset retirement obligations	**908.0**	825.0
Mark-to-market energy liabilities	**912.3**	315.0
Risk management liabilities	**1,035.5**	472.2
Unamortized energy contract liabilities	**1,118.7**	86.2
Postretirement and postemployment benefits	**382.6**	375.3
Net pension liability	**401.4**	269.7
Deferred investment tax credits	**64.1**	71.2
Other	**101.0**	145.8
Total deferred credits and other liabilities	**6,104.4**	3,863.7
Capitalization (See Consolidated Statements of Capitalization)		
Long-term debt	**4,369.3**	4,813.2
Minority interests	**22.4**	90.9
BGE preference stock not subject to mandatory redemption	**190.0**	190.0
Common shareholders' equity	**4,915.5**	4,726.9
Total capitalization	**9,497.2**	9,821.0
Commitments, Guarantees, and Contingencies (see Note 12)		
Total Liabilities and Equity	**$ 21,473.9**	$ 17,347.1

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

CONSOLIDATED STATEMENTS OF CASH FLOWS

Constellation Energy Group, Inc. and Subsidiaries

Year Ended December 31,	2005	2004	2003
		(In millions)	
Cash Flows From Operating Activities			
Net income	$ **623.1**	$ 539.7	$ 277.3
Adjustments to reconcile to net cash provided by operating activities			
(Gain) loss on sales of discontinued operations	**(13.8)**	50.1	
Cumulative effects of changes in accounting principles	**7.2**		198.4
Depreciation, depletion, and amortization	**603.0**	646.8	596.4
Accretion of asset retirement obligations	**62.1**	53.2	42.7
Deferred income taxes	**136.9**	123.4	109.2
Investment tax credit adjustments	**(7.1)**	(7.2)	(7.3)
Deferred fuel costs	**(11.9)**	6.0	(10.1)
Pension and postemployment benefits	**23.6**	(3.0)	(69.4)
Workforce reduction costs	**4.4**	9.7	2.1
Merger-related transaction costs	**17.0**		
Other non-cash (income) expense included in earnings	**(12.2)**	4.9	(25.6)
Equity in earnings of affiliates less than dividends received	**38.7**	29.5	38.4
Proceeds from derivative power sales contracts classified as financing activities under SFAS No. 149	**(72.6)**		
Changes in			
Accounts receivable	**(961.2)**	(397.4)	(282.6)
Mark-to-market energy assets and liabilities	**(88.4)**	(27.2)	14.9
Risk management assets and liabilities	**(27.5)**	(39.7)	(92.9)
Materials, supplies, and fuel stocks	**(250.3)**	(112.1)	(51.5)
Other current assets	**(277.1)**	5.3	28.8
Accounts payable and accrued liabilities	**282.8**	260.2	193.5
Other current liabilities	**546.4**	(8.7)	139.8
Other	**4.1**	(46.7)	(44.3)
Net cash provided by operating activities	**627.2**	1,086.8	1,057.8
Cash Flows From Investing Activities			
Investments in property, plant and equipment	**(760.0)**	(703.6)	(635.7)
Contract and portfolio acquisitions	**(336.2)**		
Asset acquisitions and business combinations, net of cash acquired	**(237.2)**	(457.3)	(546.6)
Investments in nuclear decommissioning trust fund securities	**(370.8)**	(424.2)	(176.0)
Proceeds from nuclear decommissioning trust fund securities	**353.2**	402.2	162.8
Net proceeds from sale of discontinued operations	**289.4**	72.7	
Issuances of loans receivable	**(82.8)**		
Sale of investments and other assets	**14.4**	36.1	148.8
Other investments	**(44.0)**	(78.6)	(113.6)
Net cash used in investing activities	**(1,174.0)**	(1,152.7)	(1,160.3)
Cash Flows From Financing Activities			
Net issuance (maturity) of short-term borrowings	**10.7**	(9.6)	(0.9)
Proceeds from issuance of			
Common stock	**96.9**	293.9	95.4
Long-term debt	**12.0**	100.0	983.3
Repayment of long-term debt	**(362.3)**	(243.2)	(707.5)

Year Ended December 31,	**2005**	**2004**	**2003**
Common stock dividends paid	**(228.8)**	(189.7)	(169.2)
Proceeds from contract and portfolio acquisitions	**1,026.9**	117.5	
Proceeds from derivative power sales contracts classified as financing activities under SFAS No. 149	**72.6**		
Other	**25.5**	(18.0)	7.7
Net cash provided by financing activities	**653.5**	50.9	208.8
Net Increase (Decrease) in Cash and Cash Equivalents	**106.7**	(15.0)	106.3
Cash and Cash Equivalents at Beginning of Year	**706.3**	721.3	615.0
Cash and Cash Equivalents at End of Year	**$ 813.0**	$ 706.3	$ 721.3
Other Cash Flow Information:			
Cash paid during the year for:			
Interest (net of amounts capitalized)	**$ 301.3**	$ 327.9	$ 335.7
Income taxes	**$ 115.3**	$ 203.9	$ 35.4

See Notes to Consolidated Financial Statements.

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

CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDERS' EQUITY AND COMPREHENSIVE INCOME

Constellation Energy Group, Inc. and Subsidiaries

	Common Stock			Accumulated Other	
Year Ended December 31, 2005, 2004, and 2003	**Shares**	**Amount**	**Retained Earnings**	**Comprehensive Loss**	**Total Amount**
	(Dollar amounts in millions, number of shares in thousands)				
Balance at December 31, 2002	164,843	$ 2,078.9	$ 1,977.6	$ (194.2)	$ 3,862.3
Comprehensive Income					
Net income			277.3		277.3
Other comprehensive income					
Reclassification of net gain on sales of securities from OCI to net income, net of taxes of $0.2				(0.4)	(0.4)
Reclassification of net gains on hedging instruments from OCI to net income, net of taxes of $10.7				(16.4)	(16.4)
Net unrealized gain on securities, net of taxes of $24.4				37.3	37.3
Net unrealized gain on hedging instruments, net of taxes of $15.8				39.9	39.9
Minimum pension liability, net of taxes of $8.2				12.6	12.6
Total Comprehensive Income			277.3	73.0	350.3
Common stock dividend declared ($1.04 per share)			(172.8)		(172.8)
Common stock issued	2,976	100.9			100.9
Other			(0.2)		(0.2)
Balance at December 31, 2003	167,819	2,179.8	2,081.9	(121.2)	4,140.5
Comprehensive Income					
Net income			539.7		539.7
Other comprehensive income					
Reclassification of net loss on securities from OCI to net income, net of taxes of $1.4				2.2	2.2
Reclassification of net gains on hedging instruments from OCI to net income, net of taxes of $169.0				(270.8)	(270.8)
Net unrealized gain on securities, net of taxes of $22.2				33.7	33.7
Net unrealized gain on hedging instruments, net of taxes of $124.7				196.8	196.8
Net unrealized gain on foreign currency translation				0.4	0.4
Minimum pension liability, net of taxes of $27.9				(42.6)	(42.6)
Total Comprehensive Income			539.7	(80.3)	459.4
Common stock dividend declared ($1.14 per share)			(196.3)		(196.3)

				Accumulated Other Comprehensive Loss	
Common stock issued	8,514	322.7			322.7
Other			0.6		0.6
Balance at December 31, 2004	176,333	2,502.5	2,425.9	(201.5)	4,726.9
Comprehensive Income					
Net income			**623.1**		**623.1**
Other comprehensive income					
Reclassification of net gains on securities from OCI to net income, net of taxes of $1.2				**(1.8)**	**(1.8)**
Reclassification of net gains on hedging instruments from OCI to net income, net of taxes of $492.2				**(794.6)**	**(794.6)**
Net unrealized gain on securities, net of taxes of $15.7				**23.8**	**23.8**
Net unrealized gain on hedging instruments, net of taxes of $335.9				**534.7**	**534.7**
Net unrealized gain on foreign currency translation				**1.0**	**1.0**
Minimum pension liability, net of taxes of $50.4				**(77.1)**	**(77.1)**
Total Comprehensive Income			**623.1**	**(314.0)**	**309.1**
Common stock dividend declared ($1.34 per share)			**(238.4)**		**(238.4)**
Common stock issued	**1,968**	**118.3**			**118.3**
Other			**(0.4)**		**(0.4)**
Balance at December 31, 2005	**178,301**	**$ 2,620.8**	**$ 2,810.2**	**$ (515.5)**	**$ 4,915.5**

See Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CAPITALIZATION

Constellation Energy Group, Inc. and Subsidiaries

At December 31,

	2005	2004
	(In millions)	
Long-Term Debt		
Long-term debt of Constellation Energy		
$7^{7}/_{8}$% Notes, due April 1, 2005	**$**	$ 300.0
6.35% Fixed-Rate Notes, due April 1, 2007	**600.0**	600.0
6.125% Fixed-Rate Notes, due September 1, 2009	**500.0**	500.0
7.00% Fixed-Rate Notes, due April 1, 2012	**700.0**	700.0
4.55% Fixed-Rate Notes, due June 15, 2015	**550.0**	550.0
7.60% Fixed-Rate Notes, due April 1, 2032	**700.0**	700.0
Fair Value of Interest Rate Swaps	**(0.9)**	13.3
Total long-term debt of Constellation Energy	**3,049.1**	3,363.3
Long-term debt of nonregulated businesses		
Tax-exempt debt transferred from BGE effective July 1, 2000		
Pollution control loan, due July 1, 2011	**36.0**	36.0
Port facilities loan, due June 1, 2013	**48.0**	48.0
Pollution control loan, due July 1, 2014	**20.0**	20.0
5.55% Pollution control revenue refunding loan, due July 15, 2014	**47.0**	47.0
Economic development loan, due December 1, 2018	**35.0**	35.0
6.00% Pollution control revenue refunding loan, due April 1, 2024	**75.0**	75.0
Floating-rate pollution control loan, due June 1, 2027	**8.8**	8.8
District Cooling facilities loan, due December 1, 2031	**25.0**	25.0
Loans under revolving credit agreements		100.1
4.875% Inflation protection loan due February 15, 2012	**12.0**	
5.00% Mortgage note, due July 5, 2010	**12.8**	
4.25% Mortgage note, due March 15, 2009	**1.9**	2.3
South Carolina synthetic fuel facility loan, due January 15, 2008	**36.0**	40.0
Total long-term debt of nonregulated businesses	**357.5**	437.2
First Refunding Mortgage Bonds of BGE		
Remarketed floating-rate series, due September 1, 2006	**97.4**	99.3
$7^{1}/_{2}$% Series, due January 15, 2007	**122.0**	122.5
$6^{5}/_{8}$% Series, due March 15, 2008	**123.4**	124.5
Total First Refunding Mortgage Bonds of BGE	**342.8**	346.3
Other long-term debt of BGE		
5.25% Notes, due December 15, 2006	**300.0**	300.0
5.20% Notes, due June 15, 2033	**200.0**	200.0
Medium-term notes, Series B	**12.0**	12.1
Medium-term notes, Series D	**10.0**	48.0
Medium-term notes, Series E	**199.5**	199.5
Medium-term notes, Series G	**140.0**	140.0
Total other long-term debt of BGE	**861.5**	899.6
6.20% deferrable interest subordinated debentures due October 15, 2043 to BGE wholly owned BGE Capital Trust II relating to trust preferred securities	**257.7**	257.7

At December 31,

	2005	2004
Unamortized discount and premium	**(8.0)**	(10.5)
Current portion of long-term debt	**(491.3)**	(480.4)
Total long-term debt	**$ 4,369.3**	$ 4,813.2

See Notes to Consolidated Financial Statements.

continued on next page

CONSOLIDATED STATEMENTS OF CAPITALIZATION

Constellation Energy Group, Inc. and Subsidiaries

At December 31,	**2005**	**2004**
	(In millions)	
Minority Interests	**$ 22.4**	$ 90.9
BGE Preference Stock		
Cumulative preference stock not subject to mandatory redemption, 6,500,000 shares authorized 7.125%, 1993 Series, 400,000 shares outstanding, callable at $102.85 per share until June 30, 2006, and at lesser amounts thereafter	**40.0**	40.0
6.97%, 1993 Series, 500,000 shares outstanding, callable at $102.79 per share until September 30, 2006, and at lesser amounts thereafter	**50.0**	50.0
6.70%, 1993 Series, 400,000 shares outstanding, callable at $102.68 per share until December 31, 2006, and at lesser amounts thereafter	**40.0**	40.0
6.99%, 1995 Series, 600,000 shares outstanding, callable at $103.50 per share until September 30, 2006, and at lesser amounts thereafter	**60.0**	60.0
Total preference stock not subject to mandatory redemption	**190.0**	190.0
Common Shareholders' Equity		
Common stock without par value, 250,000,000 shares authorized; 178,300,844 and 176,333,121 shares issued and outstanding at December 31, 2005 and 2004, respectively. (At December 31, 2005, 3,695,418 shares were reserved for the long-term incentive plans, 7,918,412 shares were reserved for the Shareholder Investment Plan, 1,520,000 shares were reserved for the continuous offering programs, and 2,007,860 shares were reserved for the employee savings plan.)	**2,620.8**	2,502.5
Retained earnings	**2,810.2**	2,425.9
Accumulated other comprehensive loss	**(515.5)**	(201.5)
Total common shareholders' equity	**4,915.5**	4,726.9
Total Capitalization	**$ 9,497.2**	$ 9,821.0

See Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF INCOME

Baltimore Gas and Electric Company and Subsidiaries

Year Ended December 31,	2005	2004	2003
		(In millions)	
Revenues			
Electric revenues	**$ 2,036.5**	$ 1,967.7	$ 1,921.6
Gas revenues	**972.8**	757.0	726.0
Total revenues	**3,009.3**	2,724.7	2,647.6
Expenses			
Operating Expenses			
Electricity purchased for resale	**1,068.9**	1,034.0	1,023.5
Gas purchased for resale	**687.5**	484.3	445.8
Operations and maintenance	**450.2**	427.8	406.2
Merger-related transaction costs	**5.4**		
Workforce reduction costs			0.7
Depreciation and amortization	**232.4**	242.3	228.3
Taxes other than income taxes	**168.4**	164.9	158.1
Total expenses	**2,612.8**	2,353.3	2,262.6
Income from Operations	**396.5**	371.4	385.0
Other Income (Expense)	**5.9**	(6.4)	(5.4)
Fixed Charges			
Interest expense	**95.6**	97.3	112.8
Allowance for borrowed funds used during construction	**(2.1)**	(1.1)	(1.6)
Total fixed charges	**93.5**	96.2	111.2
Income Before Income Taxes	**308.9**	268.8	268.4
Income Taxes			
Current	**122.6**	69.4	48.5
Deferred	**(0.9)**	34.9	58.5
Investment tax credit adjustments	**(1.8)**	(1.8)	(1.8)
Total income taxes	**119.9**	102.5	105.2
Net Income	**189.0**	166.3	163.2
Preference Stock Dividends	**13.2**	13.2	13.2
Earnings Applicable to Common Stock	**$ 175.8**	$ 153.1	$ 150.0

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Baltimore Gas and Electric Company and Subsidiaries

Year Ended December 31,	2005	2004	2003
		(In millions)	
Net Income	**$ 175.8**	$ 153.1	$ 150.0
Other comprehensive income			

Year Ended December 31,	2005	2004	2003
Reclassification of net gains on hedging instruments from OCI to net income, net of taxes of $0.0		(0.1)	
Unrealized gain on hedging instruments, net of taxes of $0.4			0.8
Comprehensive Income	**$ 175.8**	$ 153.0	$ 150.8

See Notes to Consolidated Financial Statements

CONSOLIDATED BALANCE SHEETS

Baltimore Gas and Electric Company and Subsidiaries

At December 31,

	2005	2004
	(In millions)	
Assets		
Current Assets		
Cash and cash equivalents	**$ 15.1**	$ 8.2
Accounts receivable (net of allowance for uncollectibles of **$13.0** and $13.0, respectively)	**480.5**	381.8
Investment in cash pool, affiliated company		127.9
Accounts receivable, affiliated companies	**1.8**	1.0
Fuel stocks	**102.7**	86.5
Materials and supplies	**40.1**	34.6
Prepaid taxes other than income taxes	**45.7**	44.5
Other	**6.5**	7.2
Total current assets	**692.4**	691.7
Investments and Other Assets		
Regulatory assets (net)	**154.3**	195.4
Receivable, affiliated company	**154.7**	150.4
Other	**144.0**	134.2
Total investments and other assets	**453.0**	480.0
Utility Plant		
Plant in service		
Electric	**3,891.1**	3,759.3
Gas	**1,116.7**	1,086.7
Common	**416.0**	478.4
Total plant in service	**5,423.8**	5,324.4
Accumulated depreciation	**(1,923.8)**	(1,921.5)
Net plant in service	**3,500.0**	3,402.9
Construction work in progress	**93.9**	83.1
Plant held for future use	**2.8**	5.2
Net utility plant	**3,596.7**	3,491.2
Total Assets	**$ 4,742.1**	$ 4,662.9

See Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

Baltimore Gas and Electric Company and Subsidiaries

At December 31,

	2005	2004
	(In millions)	
Liabilities and Equity		
Current Liabilities		
Current portion of long-term debt	$ **469.6**	$ 165.9
Accounts payable and accrued liabilities	**169.7**	125.4
Accounts payable and accrued liabilities, affiliated companies	**152.8**	146.1
Borrowing from cash pool, affiliated company	**3.2**	
Customer deposits	**65.1**	64.3
Accrued taxes	**35.5**	32.2
Accrued expenses and other	**79.6**	71.7
Total current liabilities	**975.5**	605.6
Deferred Credits and Other Liabilities		
Deferred income taxes	**608.9**	608.0
Postretirement and postemployment benefits	**277.7**	278.2
Deferred investment tax credits	**15.1**	16.9
Other	**19.0**	20.0
Total deferred credits and other liabilities	**920.7**	923.1
Long-term Debt		
First refunding mortgage bonds of BGE	**342.8**	346.3
Other long-term debt of BGE	**861.5**	899.6
6.20% deferrable interest subordinated debentures due October 15, 2043 to wholly owned BGE Capital Trust II relating to trust preferred securities	**257.7**	257.7
Long-term debt of nonregulated business	**25.0**	25.0
Unamortized discount and premium	**(2.3)**	(3.2)
Current portion of long-term debt	**(469.6)**	(165.9)
Total long-term debt	**1,015.1**	1,359.5
Minority Interest	**18.3**	18.7
Preference Stock Not Subject to Mandatory Redemption	**190.0**	190.0
Common Shareholder's Equity		
Common stock	**912.2**	912.2
Retained earnings	**709.6**	653.1
Accumulated other comprehensive income	**0.7**	0.7
Total common shareholder's equity	**1,622.5**	1,566.0
Commitments, Guarantees, and Contingencies (see Note 12)		

At December 31,	2005	2004
Total Liabilities and Equity	**$ 4,742.1**	$ 4,662.9

See Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Baltimore Gas and Electric Company and Subsidiaries

Year Ended December 31,	**2005**	**2004**	**2003**
		(In millions)	
Cash Flows From Operating Activities			
Net income	**$ 189.0**	$ 166.3	$ 163.2
Adjustments to reconcile to net cash provided by operating activities			
Depreciation and amortization	**247.0**	257.4	242.7
Deferred income taxes	**(0.9)**	34.9	58.5
Investment tax credit adjustments	**(1.8)**	(1.8)	(1.8)
Deferred fuel costs	**(11.9)**	6.0	(10.1)
Pension and postemployment benefits	**(1.6)**	(16.6)	(56.2)
Allowance for equity funds used during construction	**(3.9)**	(2.0)	(3.0)
Workforce reduction costs			0.7
Changes in			
Accounts receivable	**(98.7)**	(27.0)	2.7
Receivables, affiliated companies	**(0.8)**	3.5	126.7
Materials, supplies, and fuel stocks	**(21.7)**	(28.4)	(20.3)
Other current assets	**(0.5)**	1.0	(0.4)
Accounts payable and accrued liabilities	**44.3**	24.2	8.0
Accounts payable and accrued liabilities, affiliated companies	**6.7**	(5.6)	66.1
Other current liabilities	**12.0**	(10.3)	14.0
Other	**(37.4)**	(30.2)	(22.9)
Net cash provided by operating activities	**319.8**	371.4	567.9
Cash Flows From Investing Activities			
Utility construction expenditures (excluding equity portion of allowance for funds used during construction)	**(270.5)**	(246.4)	(269.0)
Change in cash pool at parent	**131.1**	102.3	107.9
Sales of investments and other assets	**11.0**	4.9	
Other	**(10.4)**	2.7	1.8
Net cash used in investing activities	**(138.8)**	(136.5)	(159.3)
Cash Flows From Financing Activities			
Proceeds from issuance of long-term debt			439.4
Repayment of long-term debt	**(41.6)**	(149.8)	(710.4)
Preference stock dividends paid	**(13.2)**	(13.2)	(13.2)
Distribution to parent	**(119.3)**	(74.7)	(124.8)
Other			1.2
Net cash used in financing activities	**(174.1)**	(237.7)	(407.8)
Net Increase (Decrease) in Cash and Cash Equivalents	**6.9**	(2.8)	0.8
Cash and Cash Equivalents at Beginning of Year	**8.2**	11.0	10.2
Cash and Cash Equivalents at End of Year	**$ 15.1**	$ 8.2	$ 11.0
Other Cash Flow Information:			

Year Ended December 31,	**2005**	2004	2003
Cash paid during the year for:			
Interest (net of amounts capitalized)	**$ 88.6**	$ 95.5	$ 120.6
Income taxes	**$ 123.3**	$ 80.7	$ 24.7

See Notes to Consolidated Financial Statements.

Notes to Consolidated Financial Statements

1 Significant Accounting Policies

Nature of Our Business

Constellation Energy Group, Inc. (Constellation Energy) is an energy company that conducts its business through various subsidiaries including a merchant energy business and Baltimore Gas and Electric Company (BGE). Our merchant energy business is a competitive provider of energy solutions for a variety of customers. BGE is a regulated electric transmission and distribution utility company and a regulated gas distribution utility company with a service territory that covers the City of Baltimore and all or part of ten counties in central Maryland. We describe our operating segments in *Note 3*.

This report is a combined report of Constellation Energy and BGE. References in this report to "we" and "our" are to Constellation Energy and its subsidiaries. References in this report to the "regulated business(es)" are to BGE.

Pending Merger with FPL Group, Inc.

In December 2005, Constellation Energy entered into an agreement and plan of merger with FPL Group, Inc. (FPL Group). We discuss the pending merger in more detail in *Note 15*.

Consolidation Policy

We use three different accounting methods to report our investments in our subsidiaries or other companies: consolidation, the equity method, and the cost method.

Consolidation

We use consolidation for two types of entities:

- subsidiaries (other than variable interest entities) in which we own a majority of the voting stock, and
- variable interest entities (VIEs) for which we are the primary beneficiary. Financial Accounting Standards Board (FASB) Interpretation No. (FIN) 46R, *Consolidation of Variable Interest Entities*, requires us to use consolidation when we are the primary beneficiary of a VIE, which means that we have a controlling financial interest in a VIE. We discuss our investments in VIEs in more detail in *Note 4*.

Consolidation means that we combine the accounts of these entities with our accounts. Therefore, our consolidated financial statements include our accounts, the accounts of our majority- owned subsidiaries that are not VIEs, and the accounts of VIEs for which we are the primary beneficiary. We have not consolidated any entities for which we do not have a controlling voting interest. We eliminate all intercompany balances and transactions when we consolidate these accounts.

The Equity Method

We usually use the equity method to report investments, corporate joint ventures, partnerships, and affiliated companies (including qualifying facilities and power projects) where we hold a 20% to 50% voting interest. Under the equity method, we report:

- our interest in the entity as an investment in our Consolidated Balance Sheets, and
- our percentage share of the earnings from the entity in our Consolidated Statements of Income.

The only time we do not use this method is if we can exercise control over the operations and policies of the company. If we have control, accounting rules require us to use consolidation.

The Cost Method

We usually use the cost method if we hold less than a 20% voting interest in an investment. Under the cost method, we report our investment at cost in our Consolidated Balance Sheets. The only time we do not use this method is when we can exercise significant influence over the operations and policies of the company. If we have significant influence, accounting rules require us to use the equity method.

Regulation of Electric and Gas Business

The Maryland Public Service Commission (Maryland PSC) and the Federal Energy Regulatory Commission (FERC) provide the final determination of the rates we charge our customers for our regulated businesses. Generally, we use the same accounting policies and practices used by nonregulated companies for financial reporting under accounting principles generally accepted in the United States of America. However, sometimes the Maryland PSC or the FERC orders an accounting treatment different from that used by nonregulated companies to determine the rates we charge our customers.

When this happens, we must defer (include as an asset or liability in our, and BGE's, Consolidated Balance Sheets and exclude from our, and BGE's, Consolidated Statements of Income) certain regulated business expenses and income as regulatory assets and liabilities. We have recorded these regulatory assets and liabilities in our, and BGE's, Consolidated Balance Sheets in accordance with Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulation.*

We summarize and discuss our regulatory assets and liabilities further in *Note 6*.

Use of Accounting Estimates

Management makes estimates and assumptions when preparing financial statements under accounting principles generally accepted in the United States of America. These estimates and assumptions affect various matters, including:

- our reported amounts of revenues and expenses in our Consolidated Statements of Income during the reporting periods,
- our reported amounts of assets and liabilities in our Consolidated Balance Sheets at the dates of the financial statements, and
- our disclosure of contingent assets and liabilities at the dates of the financial statements.

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

Reclassifications

We have reclassified certain prior-year amounts for comparative purposes. These reclassifications did not affect consolidated net income for the years presented.

Revenues

Accrual Accounting

We record revenues from the sale of energy, energy-related products, and energy services under the accrual method of accounting in the period when we deliver energy commodities or products, render services, or settle contracts. We use accrual accounting for our merchant energy and other nonregulated business transactions, including the generation or purchase and sale of electricity, gas, and coal as part of our physical delivery activities and for power, gas, and coal sales contracts that are not subject to mark-to-market accounting. Sales contracts that are eligible for accrual accounting include non-derivative transactions and derivatives that qualify for and are designated as normal purchases and normal sales of commodities that will be physically delivered. We record accrual revenues, including settlements with independent system operators, on a gross basis because we are a principal to the transaction and otherwise meet the requirements of Emerging Issues Task Force (EITF) 03-11, *Reporting Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133, Accounting for Derivative Instruments and Hedging Activities, and Not Held for Trading Purposes,* and EITF 99-19, *Reporting Revenue Gross as a Principal versus Net as an Agent*.

We may make or receive cash payments at the time we assume a power sale agreement for which the contract price differs from current market prices. We recognize the cash payment at inception in our Consolidated Balance Sheets as an "Unamortized energy contract" asset or liability. We amortize these assets and liabilities into revenues based on the expected cash flows provided by the contracts.

During 2005, we terminated or restructured several in-the-money contracts in exchange for upfront cash payments and a reduction or cancellation of future performance obligations. The termination or restructuring of two contracts allowed us to lower our exposure to performance risk under these contracts, and resulted in the realization of $77.0 million of pre-tax earnings in 2005 that would have been recognized over the life of these contracts.

Mark-to-Market Accounting

We record revenues using the mark-to-market method of accounting for derivative contracts for which we are not permitted to use accrual accounting or hedge accounting. We discuss our use of hedge accounting in the *Derivatives and Hedging Activities* section later in this Note. These mark-to-market activities include derivative contracts for energy and other energy-related commodities. Under the mark-to-market method of accounting, we record the fair value of these derivatives as mark-to-market energy assets and liabilities at the time of contract execution. Our wholesale marketing and risk management operation records changes in mark-to-market energy assets and liabilities on a net basis in "Nonregulated revenues" in our Consolidated Statements of Income. Our retail competitive supply operation records changes in sale contracts accounted for as mark-to-market in "Nonregulated revenues" in our Consolidated Statements of Income.

Mark-to-market energy assets and liabilities consist of derivative contracts. While some of these contracts represent commodities or instruments for which prices are available from external sources, other commodities and certain contracts are not actively traded and are valued using modeling techniques to determine expected future market prices, contract quantities, or both. The market prices and quantities used to determine fair value reflect management's best estimate considering various factors, including closing exchange and over-the-counter quotations, time value, and volatility factors. However, future market prices and actual quantities will vary from those used in recording mark-to-market energy assets and liabilities, and it is possible that such variations could be material.

Mark-to-market revenues include:

- gains or losses on new transactions at origination to the extent permitted by applicable accounting rules,
- unrealized gains and losses from changes in the fair value of open contracts,
- net gains and losses from realized transactions, and
- changes in valuation adjustments.

Origination gains, which are included in mark-to-market revenues, arise primarily from contracts that our wholesale marketing and risk management operation structures to meet the risk management needs of our customers. Transactions that result in origination gains may be unique and provide the potential for individually significant gains from a single transaction.

Origination gains represent the initial fair value recognized on these structured transactions. The recognition of origination gains is dependent on the existence of observable market data that validates the initial fair value of the contract. Origination gains were:

- $61.6 million pre-tax in 2005,
- $19.7 million pre-tax in 2004, and
- $62.3 million pre-tax in 2003.

Origination gains arose primarily from:

- 6 transactions completed in 2005, one of which contributed approximately $35 million pre-tax,
- 7 transactions completed in 2004, of which no transaction contributed in excess of $10 million pre-tax, and
- 14 transactions completed in 2003, of which one transaction contributed approximately $10 million pre-tax.

Valuation Adjustments

We record valuation adjustments to reflect uncertainties associated with certain estimates inherent in the determination of the fair value of mark-to-market energy assets and liabilities. To the extent possible, we utilize market-based data together with quantitative methods for both measuring the uncertainties for which we record valuation adjustments and determining the level of such adjustments and changes in those levels.

We describe below the main types of valuation adjustments we record and the process for establishing each. Generally, increases in valuation adjustments reduce our earnings, and decreases in valuation adjustments increase our earnings. However, all or a portion of the effect on earnings of changes in valuation adjustments may be offset by changes in the value of the underlying positions.

- Close-out adjustment represents the estimated cost to close out or sell to a third-party open mark-to-market positions. This valuation adjustment has the effect of valuing "long" positions (the purchase of a commodity) at the bid price and "short" positions (the sale of a commodity) at the offer price. We compute this adjustment based on our estimate of the bid/offer spread for each commodity and option price and the absolute quantity of our net open positions for each year. The level of total close-out valuation adjustments increases as we have larger unhedged positions, bid-offer spreads increase, or market information is not available, and it decreases as we reduce our unhedged positions, bid-offer spreads decrease, or market information becomes available. To the extent that we are not able to obtain observable market information for similar contracts, the close-out adjustment is equivalent to the initial contract margin, thereby recording no gain or loss at inception. In the absence of observable market information, there is a presumption that the transaction price is equal to the market value of the contract, and therefore we do not recognize a gain or loss at inception. We recognize such gains or losses in earnings as we realize cash flows under the contract or when observable market data becomes available.

- Credit-spread adjustment for risk management purposes we compute the value of our mark-to-market energy assets and liabilities using a risk-free discount rate. In order to compute fair value for financial reporting purposes, we adjust the value of our mark-to-market energy assets to reflect the credit-worthiness of each customer (counterparty) based upon either published credit ratings, or equivalent internal credit ratings and associated default probability percentages. We compute this adjustment by applying the appropriate default probability percentage to our outstanding credit exposure, net of collateral, for each counterparty. The level of this adjustment increases as our credit exposure to counterparties increases, the maturity terms of our transactions increase, or the credit ratings of our counterparties deteriorate, and it decreases when our credit exposure to counterparties decreases, the maturity terms of our transactions decrease, or the credit ratings of our counterparties improve.

Financial Statement Presentation

In the first quarter of 2003, we adopted EITF 02-3, *Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities,* which required the accrual method of accounting for energy contracts that are not derivatives and clarified when gains and losses can be recognized at the inception of derivative contracts, and recognized a $430.0 million pre-tax, or $266.1 million after-tax, charge as a cumulative effect of change in accounting principle. The contracts that were subject to the requirements of EITF 02-3 were primarily our full requirements load-serving contracts and unit-contingent power purchase contracts, which are not derivatives.

Certain transactions entered into under master agreements and other arrangements provide our merchant energy business with a right of setoff in the event of bankruptcy or default by the counterparty. We report such transactions net in our Consolidated Balance Sheets in accordance with FASB Interpretation No. 39, *Offsetting of Amounts Related to Certain Contracts*.

Equity in Earnings

We include equity in earnings from our investments in qualifying facilities and power projects in "Nonregulated revenues" in our Consolidated Statements of Income in the period they are earned.

Fuel and Purchased Energy Expenses

We incur costs for:

- the fuel we use to generate electricity,
- purchases of electricity from others, and
- natural gas and coal that we resell.

These costs are included in "Fuel and purchased energy expenses" in our Consolidated Statements of Income. We discuss certain of these separately below. We also include certain non-fuel direct costs, such as ancillary services, transmission costs, and brokerage fees in "Fuel and purchased energy expenses" in our Consolidated Statements of Income.

Our retail competitive supply operation records changes in purchase contracts accounted for as mark-to-market in "Fuel and purchased energy expenses" in our Consolidated Statements of Income.

Fuel Used to Generate Electricity and Purchases of Electricity From Others

Nonregulated Businesses

We assemble a variety of power supply resources, including baseload, intermediate, and peaking plants that we own, as well as a variety of power supply contracts that may have similar characteristics, in order to enable us to meet our customers' energy requirements, which vary on an hourly basis. We purchase power when our load-serving requirements exceed the amount of power available from our supply resources or when it is more economic to do so than to operate our power plants. The amount of power purchased depends on a number of factors, including the capacity and availability of our power plants, the level of customer demand, and the relative economics of generating power versus purchasing power from the spot market.

We also have acquired contracts and certain power purchase agreements that qualify as operating leases. Under these operating leases, we record fuel and purchased energy expense as we make fixed capacity payments, as well as variable payments based on the actual output of the plants.

We may make or receive cash payments at the time we acquire a contract or assume a power purchase agreement when the contract price differs from market prices at closing. We recognize the cash payment or receipt at inception in our Consolidated Balance Sheets as an "Unamortized energy contract" asset (payment) or liability (receipt). We amortize these assets and liabilities into fuel and purchased energy expenses based on the expected cash flows provided by the contracts.

Regulated Electric

BGE is obligated to provide market-based standard offer service to residential customers from July 1, 2006 through May 31, 2010, and for commercial and industrial customers for varying periods beyond June 30, 2004, depending on customer load. The Provider of Last Resort (POLR) rates charged during these time periods will 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.

In accordance with the POLR settlement agreement approved by the Maryland PSC, BGE defers the difference between certain of its actual costs related to the electric commodity and what it collects from customers under the commodity charge in a given period. BGE either bills or refunds its customers the difference in the future.

BGE's obligation to provide market-based standard offer service to its largest commercial and industrial customers expired May 31, 2005. BGE continues to provide an hourly-priced market-based standard offer service to those customers.

Regulated Gas

BGE charges its gas customers for the natural gas they purchase from BGE using "gas cost adjustment clauses" set by the Maryland PSC. Under these clauses, BGE defers the difference between certain of its actual costs related to the gas commodity and what it collects from customers under the commodity charge in a given period. BGE either bills or refunds its customers the difference in the future. The Maryland PSC approved a modification of the gas cost adjustment clauses to provide a market-based rates incentive mechanism. Under the market-based rates incentive 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. Effective November 2001, the Maryland PSC approved a settlement that modifies certain provisions of the market-based rates incentive mechanism. These provisions require that BGE secure fixed-price contracts for at least 10%, but not more than 20%, of forecasted system supply requirements for the November through March period. These fixed-price contracts are not subject to sharing under the market-based rates incentive mechanism.

Derivatives and Hedging Activities

We are exposed to market risk, including changes in interest rates and the impact of market fluctuations in the price and transportation costs of electricity, natural gas, and other commodities as discussed further in *Note 13*. In order to manage these risks, we use both derivative and non-derivative contracts that may provide for settlement in cash or by delivery of a commodity, including:

- forward contracts, which commit us to purchase or sell energy commodities in the future,
- futures contracts, which are exchange-traded standardized commitments to purchase or sell a commodity or financial instrument, or to make a cash settlement, at a specific price and future date,
- swap agreements, which require payments to or from counterparties based upon the differential between two prices for a predetermined contractual (notional) quantity, and
- option contracts, which convey the right to buy or sell a commodity, financial instrument, or index at a predetermined price.

SFAS No. 133*, Accounting for Derivative Instruments and Hedging Activities,* as amended, requires that we recognize at fair value all derivatives not qualifying for accrual accounting under the normal purchase and normal sale exception. We record derivatives that are designated as hedges in "Risk management assets or liabilities" and derivatives not designated as hedges in "Mark-to-market energy assets or liabilities" in our Consolidated Balance Sheets.

We record changes in the value of derivatives that are not designated as cash-flow hedges in earnings during the period of change. We record changes in the fair value of derivatives designated as cash-flow hedges that are effective in offsetting the variability in cash flows of forecasted transactions in other comprehensive income until the forecasted transactions occur. At the time the forecasted transactions occur, we reclassify the amounts recorded in other comprehensive income into earnings. We record the ineffective portion of changes in the fair value of derivatives used as cash-flow hedges immediately in earnings.

We summarize our cash-flow hedging activities under SFAS No. 133 and the income statement classification of amounts reclassified from "Accumulated other comprehensive income (loss)" as follows:

Risk	Derivative	Income Statement Classification
Interest rate risk associated with new debt issuances	Interest rate swaps	Interest expense
Nonregulated energy sales	Futures and forward contracts	Nonregulated revenues
Nonregulated fuel and energy purchases	Futures and forward contracts	Fuel and purchased energy expenses
Nonregulated gas purchases for resale	Futures and forward contracts and price and basis swaps	Fuel and purchased energy expenses
Regulated gas purchases for resale	Price and basis swaps	Fuel and purchased energy expenses

We designate certain derivatives as fair value hedges. We record changes in the fair value of these derivatives and changes in the fair value of the hedged assets or liabilities in earnings as the changes occur. We summarize our fair value hedging activities and the income statement classification of changes in the fair value of these hedges and the related hedged items as follows:

Risk	Derivative	Income Statement Classification
Optimize mix of fixed and floating-rate debt	Interest rate swaps	Interest expense
Value of natural gas in storage	Forward contracts and price and basis swaps	Fuel and purchased energy expenses

We record changes in the fair value of interest rate swaps and the debt being hedged in "Risk management assets and liabilities" and "Long-term debt" and changes in the fair value of the gas being hedged and related derivatives in "Fuel stocks" and "Risk management assets and liabilities" in our Consolidated Balance Sheets. In addition, we record the difference between interest on hedged fixed-rate debt and floating-rate swaps in "Interest expense" in the periods that the swaps settle.

Unamortized Energy Assets and Liabilities

Unamortized energy contract assets and liabilities represent the remaining unamortized balance of non-derivative energy contracts that we acquired or derivatives designated as normal purchases and normal sales that we had previously recorded as "Mark-to-market energy assets or liabilities" or "Risk management assets and liabilities." The initial amount recorded represents the fair value of the contract at the time of acquisition or designation, and the balance is amortized over the life of the contract in relation to the present value of the underlying cash flows. The amortization of these values is discussed in the *Revenues* and *Fuel and Purchased Energy Expenses* sections of this Note.

Credit Risk

Credit risk is the loss that may result from counterparty non-performance. We are exposed to credit risk, primarily through our merchant energy business. We use credit policies to manage our credit risk, including utilizing an established credit approval process, daily monitoring of counterparty limits, employing credit mitigation measures such as margin, collateral or prepayment arrangements, and using master netting agreements. We measure credit risk as the replacement cost for open energy commodity and derivative positions (both mark-to-market and accrual) plus amounts owed from counterparties for settled transactions. The replacement cost of open positions represents unrealized gains, less any unrealized losses where we have a legally enforceable right of setoff.

Electric and gas utilities, cooperatives, and energy marketers comprise the majority of counterparties underlying our assets from our wholesale marketing and risk management activities. We held cash collateral from these counterparties totaling $388.4 million as of December 31, 2005 and $145.9 million as of December 31, 2004. These amounts are included in "Customer deposits and collateral" in our Consolidated Balance Sheets.

Taxes

We summarize our income taxes in *Note 10*. BGE and our other subsidiaries record their allocated share of our consolidated federal income tax liability using the percentage complementary method specified in U.S. income tax regulations. As you read this section, it may be helpful to refer to *Note 10*.

Income Tax Expense

We have two categories of income tax expense current and deferred. We describe each of these below:

- current income tax expense consists solely of regular tax less applicable tax credits, and
- deferred income tax expense is equal to the changes in the net deferred income tax liability, excluding amounts charged or credited to accumulated other comprehensive income. Our deferred income tax expense is increased or reduced for changes to the "Income taxes recoverable through future rates (net)" regulatory asset (described later in this Note) during the year.

Tax Credits

We have deferred the investment tax credits associated with our regulated business and assets previously held by our regulated business in our Consolidated Balance Sheets. The investment tax credits are amortized evenly to income over the life of each property. We reduce current income tax expense in our Consolidated Statements of Income for the investment tax credits and other tax credits associated with our nonregulated businesses.

We have certain investments in facilities that manufacture solid synthetic fuel produced from coal as defined under the Internal Revenue Code for which we claim tax credits on our Federal income tax return. We recognize the tax benefit of these credits in our Consolidated Statements of Income when we believe it is highly probable that the credits will be sustained.

Deferred Income Tax Assets and Liabilities

We must report some of our revenues and expenses differently for our financial statements than for income tax return purposes. The tax effects of the temporary differences in these items are reported as deferred income tax assets or liabilities in our Consolidated Balance Sheets. We measure the deferred income tax assets and liabilities using income tax rates that are currently in effect.

A portion of our total deferred income tax liability relates to our regulated business, but has not been reflected in the rates we charge our customers. We refer to this portion of the liability as "Income taxes recoverable through future rates (net)." We have recorded that portion of the net liability as a regulatory asset in our Consolidated Balance Sheets. We discuss this further in *Note 6*.

State and Local Taxes

State and local income taxes are included in "Income taxes" in our Consolidated Statements of Income.

BGE also pays Maryland public service company franchise tax on distribution, and delivery of electricity and natural gas. We include the franchise tax in "Taxes other than income taxes" in our Consolidated Statements of Income.

Earnings Per Share

Basic earnings per common share (EPS) is computed by dividing earnings applicable to common stock by the weighted-average number of common shares outstanding for the year. Diluted EPS reflects the potential dilution of common stock equivalent shares that could occur if securities or other contracts to issue common stock were exercised or converted into common stock.

Our dilutive common stock equivalent shares consist of stock options and other stock-based compensation awards. The following table presents stock options that were not dilutive and were excluded from the computation of diluted EPS in each period, as well as the dilutive common stock equivalent shares as follows:

Year Ended December 31,	2005	2004	2003
		(In millions)	
Non-dilutive stock options	**0.1**		1.2
Dilutive common stock equivalent shares	**2.2**	1.0	0.4

Stock-Based Compensation

Under our long-term incentive plans, we have granted stock options, performance-based units, performance and service-based restricted stock, and equity to officers, key employees, and members of the Board of Directors. We discuss these awards in more detail in *Note 14*.

As discussed in more detail in the *Accounting Standards Adopted* section later in this Note, we elected to early adopt SFAS No. 123 Revised (SFAS No. 123R), *Share-Based Payment,* on October 1, 2005, which was prior to the required effective date of January 1, 2006. SFAS No. 123R requires companies to recognize compensation expense for all equity-based compensation awards issued to employees that are expected to vest. Equity-based compensation awards include stock options, restricted stock, and any other share-based payments.

Under SFAS No. 123R, we recognize compensation cost ratably or in tranches (depending if the award has cliff or graded vesting) over the period during which an employee is required to provide service in exchange for the award, which is typically a one to five-year period. We use a forfeiture assumption to estimate the number of awards that are expected to vest during the service period, and ultimately true-up the estimated expense to the actual expense associated with vested awards. We estimate the fair value of stock option awards on the date of grant using the Black-Scholes option-pricing model and we re-measure the fair value of liability awards each reporting period.

The following table presents the pro-forma effect on net income and earnings per share for all outstanding stock options and stock awards in each period that the fair value provisions of SFAS No. 123R were not in effect. We do not capitalize any portion of our stock-based compensation.

Year Ended December 31,	2005	2004	2003
		(In millions, except per share amounts)	
Net income, as reported	**$ 623.1**	$ 539.7	$ 277.3
Add: Actual stock-based compensation expense determined under intrinsic value method and included in reported net income, net of related tax effects	**17.8***	13.2	12.0
Deduct: Pro-forma stock-based compensation expense determined under fair value based method for all awards, net of related tax effects	**(24.5)***	(21.3)	(20.7)
Pro-forma net income	**$ 616.4**	$ 531.6	$ 268.6
Earnings per share:			
Basic as reported	**$ 3.51**	$ 3.14	$ 1.67
Basic pro-forma	**$ 3.47**	$ 3.09	$ 1.62
Diluted as reported	**$ 3.47**	$ 3.12	$ 1.66
Diluted pro-forma	**$ 3.43**	$ 3.07	$ 1.61

* *Represents expense for the nine months ended September 30, 2005, which was prior to adoption of SFAS No. 123R*

In the table above, the stock-based compensation expense included in reported net income under the intrinsic value method is as follows:

Year Ended December 31,	2005*	2004	2003
		(In millions)	
Stock options	**$ 0.3**	$ 1.0	$ 1.8
Restricted stock	**23.2**	17.0	16.4
Performance-based units	**5.1**	2.9	
Equity grants	**0.4**	0.5	0.4
Total stock-based compensation expense (pre-tax)	**$ 29.0**	$ 21.4	$ 18.6
Total stock-based compensation expense (after-tax)	**$ 17.8**	$ 13.2	$ 12.0

* *Represents expense for the nine months ended September 30, 2005, which was prior to adoption of SFAS No. 123R*

During the fourth quarter of 2005, we recognized $12.8 million after-tax, or $21.1 million pre-tax of stock-based compensation expense under the fair value method in accordance with SFAS No. 123R. This was comprised of $14.1 million for stock options, $5.0 million for restricted stock, $1.9 million for performance-based units, and $0.1 million for equity grants. We discuss our stock-based compensation plans in more detail in *Note 14*.

Cash and Cash Equivalents

All highly liquid investments with original maturities of three months or less are considered cash equivalents.

Accounts Receivable and Allowance for Uncollectibles

Accounts receivable are stated at the historical carrying amount net of write-offs and allowance for uncollectibles. We establish an allowance for uncollectibles based on our expected exposure to the credit risk of customers based on a variety of factors.

Materials, Supplies, and Fuel Stocks

We record our fuel stocks, emissions credits, coal held for resale, and materials and supplies at the lower of cost or market. We determine cost using the average cost method for all of our inventory other than our coal held for resale for which we use the specific identification method.

Financial Investments

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

SFAS No. 115, *Accounting for Certain Investments in Debt and Equity Securities,* applies particular requirements to some of our investments in debt and equity securities. We report those investments at fair value, and we use either specific identification or average cost to determine their cost for computing realized gains or losses.

Available-for-Sale Securities

We classify our investments in the nuclear decommissioning trust funds as available-for-sale securities. We describe the nuclear decommissioning trusts and the related asset retirement obligations later in this Note. In addition, we have investments in U.S. Treasury securities and trust assets securing certain executive benefits that are classified as available-for-sale securities.

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

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

Long-Lived Assets

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

We determine if long-lived assets and proved gas properties are impaired by comparing their undiscounted expected future cash flows to their carrying amount in our accounting records. We would record an impairment loss if the undiscounted expected future cash flows from an asset were less than the carrying amount of the asset. Proven gas properties' cash flows are determined at the field level. Undiscounted expected future cash flows include risk-adjusted probable and possible reserves. We are also required to evaluate our equity-method and cost-method investments (for example, in partnerships that own power projects) for impairment. APB No. 18, *The Equity Method of Accounting for Investments in Common Stock* (APB No. 18), provides the accounting requirements for these investments. The standard for determining whether an impairment must be recorded under APB No. 18 is whether the investment has experienced a loss in value that is considered an "other than a temporary" decline in value.

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

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

Debt and Equity Securities

Our investments in debt and equity securities, which primarily consist of our nuclear decommissioning trust fund investments, are subject to impairment evaluations under FASB Staff Position (FSP) 115-1, *The Meaning of Other-Than-Temporary Impairment and Its Application to Certain Investments.* FSP 115-1 requires us to determine whether a decline in fair value of an investment below the amortized cost basis is other than temporary. If we determine that the decline in fair value is judged to be other than temporary, the cost basis of the investment must be written down to fair value as a new cost basis.

Intangible Assets

Goodwill is the excess of the purchase price of an acquired business over the fair value of the net assets acquired. We account for goodwill and other intangibles under the provisions of SFAS No. 142, *Goodwill and Other Intangible Assets.* We do not amortize goodwill and certain other intangible assets. SFAS No. 142 requires us to evaluate goodwill and other intangibles for impairment at least annually or more frequently if events and circumstances indicate the business might be impaired. Goodwill is impaired if the carrying value of the business exceeds fair value. Annually, we estimate the fair value of the businesses we have acquired using techniques similar to those used to estimate future cash flows for long-lived assets as previously discussed. If the estimated fair value of the business is less than its carrying value, an impairment loss is required to be recognized to the extent that the carrying value of goodwill is greater than its fair value. SFAS No. 142 also requires the amortization of intangible assets with finite lives. We discuss the changes in our intangible assets in more detail in *Note 5*.

Property, Plant and Equipment, Depreciation, Depletion, Amortization, and Accretion of Asset Retirement Obligations

We report our property, plant and equipment at its original cost, unless impaired under the provisions of SFAS No. 144.

Our original costs include:

- material and labor,
- contractor costs, and
- construction overhead costs, financing costs, and costs for asset retirement obligations (where applicable).

We own an undivided interest in the Keystone and Conemaugh electric generating plants in Western Pennsylvania, as well as in the transmission line that transports the plants' output to the joint owners' service territories. Our ownership interests in these plants are 20.99% in Keystone and 10.56% in Conemaugh. These ownership interests represented a net investment of $171.8 million at December 31, 2005 and $190.9 million at December 31, 2004. Each owner is responsible for financing its proportionate share of the plants' working funds. Working funds are used for operating expenses and capital expenditures. Operating expenses related to these plants are included in "Operating expenses" in our Consolidated Statements of Income. Capital costs related to these plants are included in "Nonregulated property, plant and equipment" in our Consolidated Balance Sheets.

The "Nonregulated property, plant and equipment" in our Consolidated Balance Sheets includes nonregulated generation construction work in progress of $228.8 million at December 31, 2005 and $206.4 million at December 31, 2004.

When we retire or dispose of property, plant and equipment, we remove the asset's cost from our Consolidated Balance Sheets. We charge this cost to accumulated depreciation for assets that were depreciated under the group, straight-line method. This includes regulated property, plant and equipment and nonregulated generating assets transferred from BGE to our merchant energy business. For all other assets, we remove the accumulated depreciation and amortization amounts from our Consolidated Balance Sheets and record any gain or loss in our Consolidated Statements of Income.

The costs of maintenance and certain replacements are charged to "Operating expenses" in our Consolidated Statements of Income as incurred.

Our oil and gas exploration and production activities consist of working interests in gas producing fields located in Texas, Louisiana, Oklahoma, and Alabama. We account for these activities under the successful efforts method of accounting. Acquisition, development, and exploration costs are capitalized as permitted by SFAS No.19, *Financial Accounting and Reporting by Oil and Gas Producing Companies.* Costs of drilling exploratory wells are initially capitalized and later charged to expense if reserves are not discovered or deemed not to be commercially viable. Other exploratory costs are charged to expense when incurred.

Capitalized exploratory well costs were $11.4 million at December 31, 2005 and $7.2 million at December 31, 2004, and do not include amounts that were capitalized and subsequently expensed within the same period. During 2005, there were $1.4 million of well costs capitalized at December 31, 2004 that were reclassified to well, facilities, and equipment based on the determination of proved reserves.

No exploratory well costs have been capitalized for a period greater than one year since the completion of drilling.

Depreciation and Depletion Expense

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

- the group straight-line method, approved by the Maryland PSC, applied to the average investment, adjusted for anticipated costs of removal less salvage, in classes of depreciable property based on an average rate of approximately 3.5% per year for our regulated business,

- the group straight-line method using rates averaging approximately 2.5% per year for the fossil generating assets transferred from BGE to our merchant energy business and our nuclear generating assets,

- the modified units of production method (greater of straight-line method or units of production method) for fossil generating assets constructed after deregulation that were not previously owned by BGE, or

- the units-of-production method over the remaining life of the estimated proved reserves at the field level for acquisition costs and over the remaining life of proved developed reserves at the field level for development costs. The estimates for gas reserves are based on internal calculations.

Other assets are depreciated primarily using the straight-line method and the following estimated useful lives:

Asset	**Estimated Useful Lives**
Building and improvements	5 50 years
Office equipment and furniture	3 20 years
Transportation equipment	5 15 years
Computer software	3 10 years

Amortization Expense

Amortization is an accounting process of reducing an amount in our Consolidated Balance Sheets over a period of time that approximates the useful life of the related item. When we reduce amounts in our Consolidated Balance Sheets, we increase amortization expense in our Consolidated Statements of Income.

Accretion Expense

In the first quarter of 2003, we adopted SFAS No. 143, *Accounting for Asset Retirement Obligations,* which provides the accounting requirements for recognizing an estimated liability for legal obligations associated with the retirement of tangible long-lived assets, and recognized a $112.1 million pre-tax, or $67.7 million after-tax, gain as a cumulative effect of change in accounting principle.

At December 31, 2005, $883.5 million of our total asset retirement obligation of $908.0 was associated with the decommissioning of our nuclear power plants Calvert Cliffs Nuclear Power Plant (Calvert Cliffs), Nine Mile Point Nuclear Station (Nine Mile Point) and Ginna. We have also recorded asset retirement obligations associated with our other generating facilities and certain other long-lived assets. We record a liability when we are able to reasonably estimate the fair value of any future legal obligations associated with retirement that have been incurred and capitalize a corresponding amount as part of the book value of the related long-lived assets. The increase in the capitalized cost is included in determining depreciation expense over the estimated useful life of these assets. Since the fair value of the asset retirement obligations is determined using a present value approach, accretion of the liability due to the passage of time is recognized each period to "Accretion of asset retirement obligations" in our Consolidated Statements of Income until the settlement of the liability. We record a gain or loss when the liability is settled after retirement.

The change in our "Asset retirement obligations" liability during 2005 was as follows:

		(In millions)
Liability at January 1, 2005	$	825.0
Liabilities incurred		19.1
Liabilities settled		
Accretion expense		62.1
Revisions to cash flows		1.8
Liability at December 31, 2005	$	908.0

"Liabilities incurred" in the table above primarily reflect asset retirement obligations recorded in connection with the adoption of the FASB issued Interpretation No. (FIN) 47, *Accounting for Conditional Asset Retirement Obligations an Interpretation of FASB Statement No. 143*, as well as those incurred in connection with our investments in gas producing fields. FIN 47 is discussed in more detail later in this Note. We discuss the investments in gas producing fields in more detail in *Note 15*.

Nuclear Fuel

We amortize the cost of nuclear fuel, including the quarterly fees we pay to the Department of Energy for the future disposal of spent nuclear fuel, based on the energy produced over the life of the fuel. These fees are based on the kilowatt-hours of electricity sold. We report the amortization expense for nuclear fuel in "Fuel and purchased energy expenses" in our Consolidated Statements of Income.

Nuclear Decommissioning

Effective January 1, 2003, we began to record decommissioning expense for Calvert Cliffs in accordance with SFAS No. 143. The "Asset retirement obligations" liability associated with the decommissioning of Calvert Cliffs was $308.2 million at December 31, 2005 and $286.1 million at December 31, 2004. Our contributions to the nuclear decommissioning trust funds for Calvert Cliffs were $17.6 million for 2005, $22.0 million for 2004 and $13.2 million for 2003. Under the Maryland PSC's order deregulating electric generation, BGE's customers must pay a total of $520 million in 1993 dollars, adjusted for inflation, to decommission Calvert Cliffs. BGE is collecting this amount on behalf of and passing it to Calvert Cliffs Nuclear Power Plant, Inc. Calvert Cliffs Nuclear Power Plant, Inc. is responsible for any difference between this amount and the actual costs to decommission the plant.

We began to record decommissioning expense for Nine Mile Point in accordance with SFAS No. 143 on January 1, 2003. The "Asset retirement obligations" liability associated with the decommissioning was $378.7 million at December 31, 2005 and $351.5 million at December 31, 2004. We determined that the decommissioning trust funds established for Nine Mile Point are adequately funded to cover the future costs to decommission the plant and as such, no contributions were made to the trust funds during the years ended December 31, 2005, 2004, and 2003.

Upon the closing of the Ginna acquisition in 2004, the seller transferred $200.8 million in decommissioning funds. In return, we assumed all liability for the costs to decommission the unit. We believe that this transfer will be sufficient to cover the future costs to decommission the plant and as such, no contributions were made to the trust funds during the years ended December 31, 2005 and 2004. Effective June 2004, we began to record decommissioning expense for Ginna in accordance with SFAS No. 143. The "Asset retirement obligations" liability associated with the decommissioning was $196.6 million at December 31, 2005 and $184.2 million at December 31, 2004. We discuss the acquisition of Ginna in more detail in *Note 15*.

In accordance with Nuclear Regulatory Commission (NRC) regulations, we maintain external decommissioning trusts to fund the costs expected to be incurred to decommission Calvert Cliffs, Nine Mile Point, and Ginna. The NRC requires utilities to provide financial assurance that they will accumulate sufficient funds to pay for the cost of nuclear decommissioning. The assets in the trusts are reported in "Nuclear decommissioning trust funds" in our Consolidated Balance Sheets. These amounts are legally restricted for funding the costs of decommissioning. We classify the investments in the nuclear decommissioning trust funds as available-for-sale securities, and we report these investments at fair value in our Consolidated Balance Sheets as previously discussed in this Note. Investments by nuclear decommissioning trust funds are guided by the "prudent man" investment principle. The funds are prohibited from investing directly in Constellation Energy or its affiliates and any other entity owning a nuclear power plant.

As the owner of Calvert Cliffs, we are required, along with other domestic utilities, by the Energy Policy Act of 1992 to make contributions to a fund for decommissioning and decontaminating the Department of Energy's uranium enrichment facilities. The contributions are paid by BGE and generally payable over 15 years with escalation for inflation and are based upon the proportionate amount of uranium enriched by the Department of Energy for each utility. BGE will make the last payment in 2006. BGE amortizes the deferred costs of decommissioning and decontaminating the Department of Energy's uranium enrichment facilities. The previous owners retained the obligation for Nine Mile Point and Ginna.

Capitalized Interest and Allowance for Funds Used During Construction

Capitalized Interest

Our nonregulated businesses capitalize interest costs under SFAS No. 34, *Capitalizing Interest Costs,* for costs incurred to finance our power plant construction projects, real estate developed for internal use, and other capital projects.

Allowance for Funds Used During Construction (AFC)

BGE finances its construction projects with borrowed funds and equity funds. BGE is allowed by the Maryland PSC to record the costs of these funds as part of the cost of construction projects in its Consolidated Balance Sheets. BGE does this through the AFC, which it calculates using rates authorized by the Maryland PSC. BGE bills its customers for the AFC plus a return after the utility property is placed in service.

The AFC rates are 9.4% for electric plant, 8.6% for gas plant, and 9.2% for common plant. BGE compounds AFC annually. Effective December 2005, the gas plant AFC rate was reduced to 8.5%.

Long-Term Debt

We defer all costs related to the issuance of long-term debt. These costs include underwriters' commissions, discounts or premiums, other costs such as legal, accounting, and regulatory fees, and printing costs. We amortize these costs into interest expense over the life of the debt.

When BGE incurs gains or losses on debt that it retires prior to maturity, it amortizes those gains or losses over the remaining original life of the debt.

Accounting Standards Issued

FSP 115-1 and 124-1

In November 2005, FASB Staff Position SFAS 115-1 and SFAS 124-1 (FSP 115-1 and 124-1), *The Meaning of Other-Than-Temporary Impairment and its Application to Certain Investments,* was issued to replace the measurement and recognition criteria of EITF 03-1. FSP 115-1 and 124-1 references existing guidance in SFAS No. 115, *Accounting for Certain Investments in Debt and Equity Securities,* SEC Staff Accounting Bulletin No. 59, *Accounting for Noncurrent Marketable Equity Securities*, and APB No. 18. FSP 115-1 and 124-1 requires an other-than-temporary analysis to be completed each reporting period (i.e., every quarter) beginning after December 15, 2005. We do not expect the adoption of this standard to have a material impact on our, or BGE's, financial results.

Accounting Standards Adopted

SFAS No. 123 Revised

In December 2004, the FASB issued SFAS No. 123R, which revises SFAS No. 123, *Accounting for Stock-Based Compensation*, and supersedes APB No. 25, *Accounting for Stock Issued to Employees*. We previously disclosed in our 2004 Annual Report on Form 10-K that we planned to adopt SFAS No. 123R effective July 1, 2005. The Securities and Exchange Commission issued Final Rule 74 in April 2005, which delayed the required implementation of SFAS No. 123R until January 1, 2006.

We elected to early adopt SFAS No. 123R on October 1, 2005, using the Modified Prospective Application method without restatement of prior periods. Under this method, we began to amortize compensation cost for the remaining portion of our outstanding awards for which the requisite service was not yet rendered at October 1, 2005. Compensation cost for these awards will be based on the fair value of those awards as disclosed on a pro-forma basis in the *Stock-Based Compensation* section of this Note. We will determine the fair value of and account for awards that are granted, modified, or settled after October 1, 2005 in accordance with SFAS No. 123R.

We do not expect the impact of this standard on our ongoing operating results will be materially different than the results as previously disclosed on a pro-forma basis in the *Stock-Based Compensation* section of this Note. Our share-based awards will continue to be accounted for substantially as they were prior to the implementation of SFAS No. 123R, other than the requirement for expensing stock options. We recognized a small, favorable cumulative effect of change in accounting principle of $0.2 million after-tax due to the requirement to reduce compensation expense for estimated forfeitures relating to outstanding unvested service-based restricted stock awards and performance-based unit awards at October 1, 2005.

The following table presents the impact of adoption of SFAS No. 123R on income from continuing operations, income before income taxes, net income, cash flow from operating and financing activities, and basic and diluted earnings per share:

Year Ended December 31, 2005	**As Reported Including SFAS No. 123R Adoption**	**Pro-Forma Excluding SFAS No. 123R Adoption**	**Impact**
	(In millions, except share data)		
Income before income taxes	$ 810.8	$ 824.9	$ (14.1)
Income from continuing operations	606.7	615.2	(8.5)
Net income	623.1	631.6	(8.5)
Net cash provided by operating activities	672.5	706.4	(33.9)
Net cash provided by financing activities	351.1	317.2	33.9
Earnings per share basic	3.51	3.56	(0.05)
Earnings per share diluted	3.47	3.51	(0.04)

The adoption of SFAS No. 123R did not have a material impact on BGE's financial results. We discuss our stock-based compensation programs in more detail in *Note 14*.

SFAS No. 153

In December 2004, the FASB issued SFAS No. 153, *Exchanges of Nonmonetary Assets, an amendment of APB Opinion No. 29*. SFAS No. 153 amends APB Opinion No. 29 to require nonmonetary exchanges to be measured at the fair value of the exchanged assets unless the transaction does not have commercial substance. SFAS No. 153 was effective for nonmonetary exchanges occurring after June 30, 2005. The adoption of this standard did not have a material impact on our, or BGE's, financial results.

FIN 47

In March 2005, the FASB issued FIN 47, *Accounting for Conditional Asset Retirement Obligations an Interpretation of FASB Statement No. 143*. FIN 47 was effective December 31, 2005. FIN 47 clarifies that asset retirement obligations that are conditional upon a future event are subject to the provisions of SFAS No. 143. Under SFAS No. 143, we are required to recognize an estimated liability for legal obligations associated with the retirement of tangible long-lived assets. Our conditional asset retirement obligations relate primarily to asbestos removal at certain of our generating facilities. We recorded an asset retirement obligation for these facilities of $13.9 million and recorded a $7.4 million after-tax charge to earnings as a cumulative effect of change in accounting principle. The adoption of FIN 47 did not have a material impact on BGE's financial results.

2 Other Events

2005 Events

	Pre-Tax	After-Tax
	(In millions)	
Merger-related transaction costs	$ (17.0)	$ (15.6)
Workforce reduction costs	(4.4)	(2.6)
Income from discontinued operations		
International investments	40.1	20.6
Oleander	4.9	3.0
Total income from discontinued operations	45.0	23.6
Total other items	$ 23.6	$ 5.4

Merger-Related Transaction Costs

We incurred external costs associated with the execution of our merger agreement with FPL Group. We discuss the pending merger in more detail in *Note 15*.

Workforce Reduction Costs

As a result of the workforce reduction efforts initiated in 2004, in 2005 we were required to record a pre-tax settlement charge in our Consolidated Statements of Income of $4.4 million for one of our qualified pension plans under SFAS No. 88, *Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits*. This charge reflects recognition of the portion of deferred actuarial gains and losses associated with employees who were terminated as part of the restructuring or retired in 2005 and who elected to receive their pension benefit in the form of a lump-sum payment. In accordance with SFAS No. 88, a settlement charge must be recognized when lump-sum payments exceed annual pension plan service and interest cost.

In 2005, we completed the 2004 workforce reduction effort. As a result, no involuntary severance liability was recorded at December 31, 2005.

Discontinued Operations

Oleander

In March 2005, we reached an agreement in principle to sell our Oleander generating facility, a four-unit peaking plant located in Florida. Our merchant energy business classified Oleander as held for sale and performed an impairment test under SFAS No. 144 as of March 31, 2005. The impairment test indicated that the carrying value of the plant was higher than its fair value less costs to sell, and therefore in March 2005 we recorded an impairment charge of $4.8 million pre-tax as part of discontinued operations.

In June 2005, we completed the sale of this facility for $217.6 million, and recognized a pre-tax gain on the sale of $1.2 million as part of discontinued operations.

International Investments

In October 2005, we sold Constellation Power International Investments, Ltd. (CPII). CPII held our other nonregulated international investments, which represented an interest in a Panamanian electric distribution company and an investment in a fund that holds interests in two South American energy projects. We received cash of $71.8 million and recognized a pre-tax gain of approximately $25.6 million, or $16.1 million after-tax. An additional $3.6 million of the sales price is contingent upon the collection of certain receivables by March 31, 2006. At December 31, 2005, we recognized approximately $2.2 million of this amount based on cash collections, which is included in the

$25.6 million pre-tax gain. We expect to recognize the remaining $1.4 million of contingent proceeds in 2006 once realization is assured beyond a reasonable doubt.

Presented in the table below are the amounts related to these discontinued operations that are included in "Income (loss) from discontinued operations" in our Consolidated Statements of Income.

	Oleander			International Investments			Total		
Year Ended December 31,	**2005**	**2004**	**2003**	**2005**	**2004**	**2003**	**2005**	**2004**	**2003**
					(In millions)				
Revenues	**$ 14.7**	$ 42.5	$ 45.4	**$ 228.1**	$ 219.7	$ 214.5	**$ 242.8**	$ 262.2	$ 259.9
Income before income taxes	**8.5**	20.5	20.2	**14.5**	16.8	17.7	**23.0**	37.3	37.9
Net income	**5.3**	12.6	11.9	**4.5**	9.4	7.1	**9.8**	22.0	19.0
Pre-tax impairment charge	**(4.8)**						**(4.8)**		
After-tax impairment charge	**(3.0)**						**(3.0)**		
Pre-tax gain on sale	**1.2**			**25.6**			**26.8**		
After-tax gain on sale	**0.7**			**16.1**			**16.8**		
Income from discontinued operations, net of taxes	**3.0**	12.6	11.9	**20.6**	9.4	7.1	**23.6**	22.0	19.0

We recognized a pre-tax loss from discontinued operations of $(75.6) million, before income taxes of $(26.5) million from the sale of our Hawaiian Geothermal facility in 2004. We discuss the sale of this facility later in this Note.

2004 Events

	Pre-Tax	After-Tax
	(In millions)	
Workforce reduction costs	$ (9.7)	$ (5.9)
Recognition of 2003 synthetic fuel tax credits		35.9
(Loss) income from discontinued operations		
Hawaiian geothermal facility	(75.6)	(49.1)
International investments	16.8	9.4
Oleander	20.5	12.6
Total loss from discontinued operations	(38.3)	(27.1)
Total other items	$ (48.0)	$ 2.9

"Loss (income) from discontinued operations" reflects the reclassification of earnings from our Oleander and international operations due to their sale in 2005.

Workforce Reduction Costs

In the fourth quarter of 2004, we approved a restructuring of the work forces of the Nine Mile Point and Calvert Cliffs nuclear generating stations that was effective in January 2005. In connection with this restructuring, approximately 108 employees received severance and other benefits under our existing benefit programs. At December 31, 2004, we accrued the estimated total cost of this reduction in workforce of $9.7 million pre-tax, or $5.9 million after-tax, in accordance with applicable accounting requirements.

Synthetic Fuel Tax Credits

In 2003, we purchased 99% ownership in a South Carolina facility that produces synthetic fuel. We did not recognize in our Consolidated Statements of Income the tax benefit of $35.9 million for credits claimed on our South Carolina facility in 2003 pending receipt of a favorable private letter ruling from the Internal Revenue Service (IRS). In April 2004, we received a favorable private letter ruling. We believe receipt of the private letter ruling provides assurance that it is highly probable that the credits will be sustained. Therefore, we recognized the tax benefit of $35.9 million in our Consolidated Statements of Income in 2004. We discuss the synthetic fuel tax credits in more detail in *Note 10.*

Loss from Discontinued Operations

In the fourth quarter of 2003, we began to re-evaluate our strategy regarding our geothermal generating facility in Hawaii. The reevaluation of our strategy included soliciting bids to determine the level of interest in the facility. As of December 31, 2003, management determined that disposal of the facility was more likely than not to occur. As a result, we evaluated the facility for impairment as of December 31, 2003, in accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets,* and determined that the facility was not impaired primarily due to indicative bids from third parties above the carrying value of the assets.

In March 2004, after reviewing final binding offers, management committed to a plan to sell the facility that met the "held for sale" criteria under SFAS No. 144. Under SFAS No. 144, we record assets and liabilities held for sale at the lesser of the carrying amount or fair value less cost to sell.

The fair value of the facility as of March 31, 2004, based on the bids under consideration, was below carrying value. Therefore, we recorded a $71.6 million pre-tax, or $47.3 million after-tax, impairment charge during the first quarter of 2004. We reported the after-tax impairment charge as a component of "Loss from discontinued operations" in our Consolidated Statements of Income. Additionally, we recognized $1.5 million pre-tax, or $1.0 million after-tax, of earnings from the facility for the quarter ended March 31, 2004 as a component of "Loss from discontinued operations."

In June 2004, we completed the sale of the facility. Based on the final sales price and other costs incurred over the remainder of the year, we recognized an additional loss of $5.5 million pre-tax, or $2.8 million after-tax. The sale of this facility was reflected in our merchant energy business reportable segment. In addition, as a result of a current audit relating to prior tax years for this facility, we could record additional gain or loss from discontinued operations in future periods.

We have not reclassified the prior year results of operations, which were reported under the equity method as "Nonregulated revenues," based on the immateriality of the amounts involved. The facility had a $4.0 million net loss, including a $1.1 million cumulative effect of change in accounting principle for the adoption of SFAS No. 143, during 2003.

2003 Events

	Pre-Tax	After-Tax
	(In millions)	
Workforce reduction costs	$ (2.1)	$ (1.3)
Income from discontinued operations		
International Investments	17.7	7.1
Oleander	20.2	11.9
Total income from discontinued operations	37.9	19.0
Total other items	$ 35.8	$ 17.7

"Income from discontinued operations" reflects the reclassification of earnings from our Oleander and international operations due to their sale in 2005.

Workforce Reduction Costs

During 2003, we recorded $2.1 million in pre-tax expense, or $1.3 million after-tax, of which BGE recorded $0.7 million pre-tax, associated with deferred payments to employees eligible for the 2001 Voluntary Special Early Retirement Program.

Hurricane Isabel

In September 2003, Hurricane Isabel caused damage to the electric and gas distribution system of BGE. As a result, BGE incurred capitalized costs of $32.0 million and maintenance expenses of $36.8 million, or $22.2 million after-tax to restore its distribution system. The maintenance expenses included $32.1 million pre-tax, or $19.4 million after-tax, of incremental expenses.

3 Information by Operating Segment

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

- Our merchant energy business is nonregulated and includes:
  - full requirements load-serving sales of energy and capacity to utilities and commercial, industrial, and governmental customers,
  - structured transactions and risk management services for various customers (including hedging of output from generating facilities and fuel costs and trading activities managed through daily value at risk and stop loss limits and liquidity guidelines),
  - gas retail energy products and services to commercial, industrial, and governmental customers,
  - fossil, nuclear, and interests in hydroelectric generating facilities and qualifying facilities, fuel processing facilities, and power projects in the United States,
  - products and services to upstream (exploration and production) and downstream (transportation and storage) wholesale natural gas customers,
  - coal sourcing services for the variable or fixed supply needs of North American and international power generators, and
  - generation operations and maintenance services.
- Our regulated electric business purchases, transmits, distributes, and sells electricity in Central Maryland.
- Our regulated gas business purchases, transports, and sells natural gas in Central Maryland.

Our remaining nonregulated businesses:

- design, construct, and operate heating, cooling, and cogeneration facilities for commercial, industrial, and municipal customers throughout North America, and
- provide home improvements, service electric and gas appliances, service heating, air conditioning, plumbing, electrical, and indoor air quality systems, and provide natural gas marketing to residential customers in Central Maryland.

In addition, we own several investments that we do not consider to be core operations. These include financial investments and real estate projects. During 2005, we sold our other nonregulated international investments. We discuss this sale in more detail in *Note 2*.

Our Merchant Energy, Regulated Electric, and Regulated Gas reportable segments are strategic businesses based principally upon regulations, products, and services that require different technology and marketing strategies. We evaluate the performance of these segments based on net income. We account for intersegment revenues using market prices. We present a summary of information by operating segment on the next page.

	Reportable Segments					
	Merchant Energy Business	Regulated Electric Business	Regulated Gas Business	Other Nonregulated Businesses	Eliminations	Consolidated
				(In millions)		
2005						
Unaffiliated revenues	**$ 13,926.8**	**$ 2,036.5**	**$ 961.7**	**$ 207.0**	**$**	**$ 17,132.0**
Intersegment revenues	**859.3**		**11.1**		**(870.4)**	
Total revenues	**14,786.1**	**2,036.5**	**972.8**	**207.0**	**(870.4)**	**17,132.0**
Depreciation, depletion, and amortization	**269.6**	**185.8**	**46.6**	**40.2**		**542.2**
Fixed charges	**177.9**	**80.3**	**26.4**	**10.0**	**15.5**	**310.1**
Income tax expense	**81.9**	**101.2**	**21.2**	**(0.2)**		**204.1**
Income on discontinued operations	**3.0**			**20.6**		**23.6**
Cumulative effects of changes in accounting principles	**(7.4)**			**0.2**		**(7.2)**
Net income (a)	**425.8**	**149.4**	**26.7**	**21.2**		**623.1**
Segment assets	**16,620.4**	**3,424.4**	**1,222.5**	**476.1**	**(269.5)**	**21,473.9**
Capital expenditures	**708.9**	**240.7**	**50.6**	**31.8**		**1,032.0**
2004						
Unaffiliated revenues	$ 9,362.9	$ 1,967.6	$ 755.0	$ 200.9	$	$ 12,286.4
Intersegment revenues	984.6	0.1	2.0	0.2	(986.9)	
Total revenues	10,347.5	1,967.7	757.0	201.1	(986.9)	12,286.4
Depreciation and amortization	239.2	194.2	48.1	24.2		505.7
Fixed charges	196.2	80.3	29.1	15.4	5.8	326.8
Income tax expense	61.3	86.8	15.9	(7.1)		156.9
(Loss) income on discontinued operations	(36.5)			9.4		(27.1)
Net income (loss) (b)	389.9	131.1	22.2	(3.5)		539.7
Segment assets	12,395.6	3,402.2	1,163.4	675.7	(289.8)	17,347.1
Capital expenditures	455.0	209.0	56.0	42.0		762.0
2003						
Unaffiliated revenues	$ 6,420.5	$ 1,921.5	$ 712.7	$ 399.4	$	$ 9,454.1
Intersegment revenues	1,167.0	0.1	13.3	0.2	(1,180.6)	
Total revenues	7,587.5	1,921.6	726.0	399.6	(1,180.6)	9,454.1
Depreciation and amortization	214.6	181.7	46.6	11.0		453.9
Fixed charges	191.9	96.8	28.2	17.3	2.3	336.5
Income tax expense	138.6	73.5	32.0	6.5		250.6
Income on discontinued operations	11.9			7.1		19.0
Cumulative effects of changes in accounting principles	(198.4)					(198.4)
Net income (c)	114.6	107.5	43.0	12.2		277.3
Segment assets	10,503.7	3,512.0	1,069.1	778.7	(270.5)	15,593.0
Capital expenditures	419.0	236.0	53.0	53.0		761.0

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

(a)

Our merchant energy business, our regulated electric business, our regulated gas business, and our other nonregulated businesses recognized after-tax charges of $13.0 million, $3.7 million, $1.3 million, and $0.2 million for merger-related transaction costs and *workforce reduction costs as described in more detail in Note 2.*

(b)
Our merchant energy business recognized after-tax income of $30.0 million, for recognition of 2003 synthetic fuel tax credits and workforce reduction costs as described in more detail in Note 2.

(c)
Our merchant energy business, our regulated electric business, our regulated gas business, and our other nonregulated businesses recognized after-tax charges of $0.7 million, $0.4 million, $0.1 million, and $0.1 million, respectively, for workforce reduction costs as described in more detail in Note 2.

4 Investments

Investments in Qualifying Facilities and Power Projects

Our merchant energy business holds up to a 50% voting interest in 24 operating domestic energy projects that consist of electric generation, fuel processing, or fuel handling facilities. Of these 24 projects, 17 are "qualifying facilities" that receive certain exemptions and pricing under the Public Utility Regulatory Policy Act of 1978 based on the facilities' energy source or the use of a cogeneration process.

Investments in qualifying facilities and domestic power projects held by our merchant energy business consist of the following:

At December 31,		**2005**		2004
		(In millions)		
Coal	**$**	**127.8**	$	128.7
Hydroelectric		**55.9**		55.8
Geothermal		**43.7**		46.3
Biomass		**48.0**		50.2
Fuel Processing		**23.8**		22.5
Solar		**7.0**		10.4
Total	**$**	**306.2**	$	313.9

Investments in qualifying facilities and domestic power projects were accounted for under the following methods:

At December 31,		**2005**		2004
		(In millions)		
Equity method	**$**	**299.2**	$	303.5
Cost method		**7.0**		10.4
Total power projects	**$**	**306.2**	$	313.9

Our percentage voting interest in qualifying facilities and domestic power projects accounted for under the equity method ranges from 16% to 50%. Equity in earnings of these power projects was $3.6 million in 2005, $18.0 million in 2004, and $2.1 million in 2003.

Our power projects include investments of $228.6 million in 2005 and $240.2 million in 2004 that sell electricity in California under power purchase agreements. Our other nonregulated businesses also held international energy projects accounted for under the equity method of $4.5 million at December 31, 2004. In 2005, we sold our interests in the international energy projects. We discuss this sale in more detail in *Note 2*.

Investments Classified as Available-for-Sale

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

- nuclear decommissioning trust funds,
- investments in treasury securities, and
- trust assets securing certain executive benefits.

This means we do not expect to hold them to maturity, and we do not consider them trading securities.

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

At December 31, 2005	Amortized Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value
		(In millions)		
Marketable equity securities	$ **804.4**	$ **112.7**	$ **(3.8)**	$ **913.3**
Corporate debt and U.S. treasuries	**114.8**	**0.2**	**(1.4)**	**113.6**
State municipal bonds	**107.1**	**2.8**	**(0.8)**	**109.1**
Totals	$ **1,026.3**	$ **115.7**	$ **(6.0)**	$ **1,136.0**

At December 31, 2004	Amortized Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value
		(In millions)		
Marketable equity securities	$ 786.1	$ 72.5	$ (2.5)	$ 856.1
Corporate debt and U.S. treasuries	73.7	0.7	(0.2)	74.2
State municipal bonds	94.3	2.9	(0.2)	97.0
Totals	$ 954.1	$ 76.1	$ (2.9)	$ 1,027.3

In addition to the above securities, the nuclear decommissioning trust funds included $12.2 million at December 31, 2005 and $30.6 million at December 31, 2004 of cash and cash equivalents.

The preceding tables include $110.3 million in 2005 of net unrealized gains and $73.3 million in 2004 of net unrealized gains associated with the nuclear decommissioning trust funds that are reflected as a change in the nuclear decommissioning trust funds in our Consolidated Balance Sheets.

We have unrealized losses relating to certain available-for-sale investments included in our decommissioning trust funds. We believe these losses are temporary in nature and expect the investments to recover their value in the future given the long-term nature of these investments. Decommissioning will not occur until the operating licenses for our nuclear facilities expire. We show the fair values and unrealized losses of our investments that were in a loss position at December 31, 2005 and 2004 in the tables on the next page.

At December 31, 2005

Description of Securities	Less than 12 months Fair Value	Less than 12 months Unrealized Losses	12 months or more Fair Value	12 months or more Unrealized Losses	Total Fair Value	Total Unrealized Losses
			(In millions)			
Marketable equity securities	**$ 22.3**	**$ (2.9)**	**$ 2.3**	**$ (0.3)**	**$ 24.6**	**$ (3.2)**
Corporate debt and U.S. treasuries	**71.8**	**(1.1)**	**11.8**	**(0.3)**	**83.6**	**(1.4)**
State municipal bonds	**46.0**	**(0.6)**	**11.8**	**(0.2)**	**57.8**	**(0.8)**
Total temporarily impaired securities	**$ 140.1**	**$ (4.6)**	**$ 25.9**	**$ (0.8)**	**$ 166.0**	**$ (5.4)**

At December 31, 2004

Description of Securities	Less than 12 months Fair Value	Less than 12 months Unrealized Losses	12 months or more Fair Value	12 months or more Unrealized Losses	Total Fair Value	Total Unrealized Losses
			(In millions)			
Marketable equity securities	$ 23.6	$ (2.4)	$	$	$ 23.6	$ (2.4)
Corporate debt and U.S. treasuries	15.3	(0.1)	10.1	(0.1)	25.4	(0.2)
State municipal bonds	18.7	(0.2)	3.3		22.0	(0.2)
Total temporarily impaired securities	$ 57.6	$ (2.7)	$ 13.4	$ (0.1)	$ 71.0	$ (2.8)

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

	2005	2004	2003
		(In millions)	
Gross realized gains	**$ 12.3**	$ 4.1	$ 6.7
Gross realized losses	**(9.3)**	(7.7)	(6.1)
Net realized (losses) gains	**$ 3.0**	$ (3.6)	$ 0.6

Gross realized losses for 2004 include a $4.5 million pre-tax impairment charge we recognized on a nuclear decommissioning trust fund investment that we believed represented an other than temporary decline in value.

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

At December 31, 2005

At December 31, 2005

		(In millions)
Less than 1 year	$	0.9
1-5 years		58.0
5-10 years		95.3
More than 10 years		68.5
Total maturities of debt securities	$	222.7

Investments in Variable Interest Entities

We have a significant interest in the following variable interest entities (VIE) for which we are not the primary beneficiary:

VIE	Nature of Involvement	Date of Involvement
Power projects and fuel supply entities	Equity investment and guarantees	Prior to 2003
Power contract monetization entities	Power sale agreements, loans, and guarantees	March 2005

We discuss the nature of our involvement with the power contract monetization VIEs in the *Customer Contract Restructuring* section on the next page.

The following is summary information available as of December 31, 2005 about the VIEs in which we have a significant interest, but are not the primary beneficiary:

	Power Contract Monetization VIEs	All Other VIEs	Total
		(In millions)	
Total assets	$ 898.2	$ 226.0	$ 1,124.2
Total liabilities	650.7	76.1	726.8
Our ownership interest		46.0	46.0
Other ownership interests	247.5	103.9	351.4
Our maximum exposure to loss	75.8	67.8	143.6

The maximum exposure to loss represents the loss that we would incur in the unlikely event that our interests in all of these entities were to become worthless and we were required to fund the full amount of all guarantees associated with these entities. Our maximum exposure to loss as of December 31, 2005 consists of the following:

outstanding loans and letters of credit totaling $85.2 million,

the carrying amount of our investment totaling $45.7 million, and

debt and performance guarantees totaling $12.7 million.

We assess the risk of a loss equal to our maximum exposure to be remote.

Customer Contract Restructuring

In March 2005, our merchant energy business closed a transaction in which we assumed from a counterparty two power sales contracts with existing VIEs. Under the contracts, we sell power to the VIEs which, in turn, sell that power to an electric distribution utility through 2013.

The VIEs previously were created by the counterparty to issue debt in order to monetize the value of the original contracts to purchase and sell power. The difference between the contract prices at which the VIEs purchase and sell power is used to service the debt of the VIEs, which totaled $619 million at December 31, 2005.

The market price for power at the closing of our transaction was higher than the contract price under the existing power sales contracts we assumed. Therefore, we received compensation totaling $308.5 million, equal to the net present value of the difference between the contract price under the power sales contracts and the market price of power at closing. We used a portion of this amount to settle $68.5 million of existing derivative liabilities with the same counterparty, and we also loaned $82.8 million to the holder of the equity in the VIEs. As a result, we received net cash at closing of $157.2 million. We also guaranteed our subsidiaries' performance under the power sales contracts.

The table below summarizes the transaction and the net cash received at closing:

		(In millions)
Gross compensation from original power sales contracts counterparty equal to fair value of power sales contracts at closing	$	308.5
Settlement of existing derivative liabilities		(68.5)
Third-party loan secured by equity in VIE		(82.8)
Net cash received at closing	$	157.2

We recorded the closing of this transaction in our financial statements as follows:

	Balance Sheet	**Cash Flows**
Fair value of power sales contracts assumed (designated as cash-flow hedge)	Risk management liabilities	Financing cash inflow
Settlement of existing derivative liabilities	Mark-to-market and risk management liabilities	Operating cash outflow
Third-party loan	Other assets	Investing cash outflow

We recorded the gross compensation we received to assume the power sales contracts as a financing cash inflow because it constitutes a prepayment for a portion of the market price of power, which we will sell to the VIEs over the term of the contracts and does not represent a cash inflow from current period operating activities. We record the ongoing cash flows related to the sale of power to the VIEs as a financing cash inflow in accordance with SFAS No. 149, *Amendment of FASB Statement No. 133 on Derivative and Hedging Activities*.

If the electric distribution utility were to default under its obligation to buy power from the VIEs, the equity holder could transfer its equity interests to us in lieu of repaying the loan. In this event, we would have the right to seek recovery of our losses from the electric distribution utility.

5 Intangible Assets

Goodwill

Goodwill is the cost of an acquisition less the fair value of the net assets acquired. Our goodwill balance is primarily related to our merchant energy business acquisitions that occurred in 2002 and 2003. The changes in the carrying amount of goodwill for the years ended December 31, 2005 and 2004 are as follows:

2005	Balance at January 1,	Goodwill Acquired	Other	Balance at December 31,
		(In millions)		
Goodwill	**$ 144.8**	**$ 2.3**	**$**	**$ 147.1**

2004	Balance at January 1,	Goodwill Acquired	Other(a)	Balance at December 31,
		(In millions)		
Goodwill	$ 146.3	$	$ (1.5)	$ 144.8

(a) Other represents purchase price adjustments

Goodwill is not amortized; rather, it is evaluated for impairment at least annually. We evaluated our goodwill in 2005 and 2004 and determined that it was not impaired. For tax purposes, $118.0 million of our goodwill balance is deductible.

Intangible Assets Subject to Amortization

Intangible assets with finite lives are subject to amortization over their estimated useful lives. The primary assets included in this category are as follows:

At December 31,	2005			2004		
	Gross Carrying Amount	Accumul-ated Amortiz-ation	Net Asset	Gross Carrying Amount	Accumul-ated Amortiz-ation	Net Asset
			(In millions)			
Software	**$ 364.7**	**$ 156.5**	**$ 208.2**	$ 388.4	$ 205.4	$ 183.0
Permits and licenses	**49.4**	**12.6**	**36.8**	37.7	5.7	32.0
Operating manuals and procedures	**38.6**	**6.0**	**32.6**	38.6	4.5	34.1
Other	**29.7**	**14.3**	**15.4**	20.0	12.1	7.9
Total	**$ 482.4**	**$ 189.4**	**$ 293.0**	$ 484.7	$ 227.7	$ 257.0

BGE had intangible assets with a gross carrying amount of $181.4 million and accumulated amortization of $98.7 million in 2005 and a gross carrying amount of $253.1 million and accumulated amortization of $161.2 million in 2004 and are included in the table above. Substantially all of BGE's intangible assets relate to software.

We recognized amortization expense related to our intangible assets as follows:

Year Ended December 31,	2005	2004	2003
		(In millions)	
Nonregulated businesses	**$ 56.9**	$ 114.2	$ 84.6
BGE	**26.3**	41.4	33.0
Total Constellation Energy	**$ 83.2**	$ 155.6	$ 117.6

The following is our, and BGE's, estimated amortization expense for 2006 through 2010 for the intangible assets included in our, and BGE's, Consolidated Balance Sheets at December 31, 2005:

Year Ended December 31,	*2006*	*2007*	*2008*	*2009*	*2010*
			(In millions)		
Estimated amortization expense Nonregulated businesses	$ 30.9	$ 29.2	$ 23.9	$ 21.5	$ 18.8
Estimated amortization expense BGE	17.7	15.3	12.6	9.9	9.5
Total estimated amortization expense Constellation Energy	$ 48.6	$ 44.5	$ 36.5	$ 31.4	$ 28.3

Unamortized Energy Contracts

As discussed in *Note 1*, unamortized energy contract assets and liabilities represent the remaining unamortized balance of nonderivative energy contracts acquired or derivatives designated as normal purchases and normal sales, which we previously recorded as mark-to-market energy or risk management assets and liabilities.

During 2005, we acquired several pre-existing nonderivative contracts that had been originated by other parties in prior periods when market prices were lower than current levels, for which we received approximately $530 million in cash and other consideration and recorded a liability in "Unamortized energy contracts." In addition, during 2005, we designated as normal purchases and normal sales contracts that we had previously recorded as cash-flow hedges in "Risk management liabilities." This resulted in a reclassification of $888.5 million from "Risk management liabilities" to "Unamortized energy contract liabilities."

We present separately in our Consolidated Balance Sheets the net unamortized energy contract assets and liabilities for these contracts. The table below presents the gross and net carrying amount and accumulated amortization of the net liability that we have recorded in our Consolidated Balance Sheets:

At December 31,		*2005*			*2004*	
	Carrying Amount	**Accumul-ated Amortiz-ation**	**Net Liability**	**Carrying Amount**	**Accumul-ated Amortiz-ation**	**Net Liability**
			(In millions)			
Unamortized energy contracts, net	**$ (1,449.2)**	**$ (37.8)**	**$ (1,411.4)**	$ (4.9)	$ 31.2	$ (36.1)

The table below presents the estimated net impact on our operating results for the amortization for these assets and liabilities over the next five-years:

Year Ended December 31,	*2006*	*2007*	*2008*	*2009*	*2010*
			(In millions)		

Year Ended December 31,	*2006*	*2007*	*2008*	*2009*	*2010*
Estimated amortization	$ (433.7)	$ (310.4)	$ (226.5)	$ (153.3)	$ (145.4)

6 Regulatory Assets (net)

As discussed in *Note 1*, the Maryland PSC and the FERC provide the final determination of the rates we charge our customers for our regulated businesses. Generally, we use the same accounting policies and practices used by nonregulated companies for financial reporting under accounting principles generally accepted in the United States of America. However, sometimes the Maryland PSC or FERC orders an accounting treatment different from that used by nonregulated companies to determine the rates we charge our customers. When this happens, we must defer certain regulated expenses and income in our Consolidated Balance Sheets as regulatory assets and liabilities. We then record them in our Consolidated Statements of Income (using amortization) when we include them in the rates we charge our customers.

We summarize regulatory assets and liabilities in the following table, and we discuss each of them separately below.

At December 31,		**2005**		**2004**
		(In millions)		
Electric generation-related regulatory asset	**$**	**173.6**	$	192.4
Net cost of removal		**(148.7)**		(132.5)
Income taxes recoverable through future rates (net)		**70.9**		74.9
Deferred postretirement and postemployment benefit costs		**22.6**		25.8
Deferred environmental costs		**14.9**		17.6
Deferred fuel costs (net)		**16.2**		4.3
Workforce reduction costs		**7.3**		14.1
Other (net)		**(2.5)**		(1.2)
Total regulatory assets (net)	**$**	**154.3**	$	195.4

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

Electric Generation-Related Regulatory Asset

As a result of the deregulation of electric generation, BGE does not meet the requirements for the application of SFAS No. 71 for the electric generation portion of its business. In accordance with SFAS No. 101, *Regulated Enterprises Accounting for the Discontinuation of Application of FASB Statement No. 71*, and EITF 97-4, *Deregulation of the Pricing of Electricity Issues Related to the Application of FASB Statements No. 71 and 101*, all individual generation-related regulatory assets and liabilities must be eliminated from our balance sheet unless these regulatory assets and liabilities will be recovered in the regulated portion of the business. BGE wrote-off all of its individual, generation-related regulatory assets and liabilities. BGE established a single, new generation-related regulatory asset for amounts to be collected through its regulated transmission and distribution business. The new regulatory asset is being amortized on a basis that approximates the pre-existing individual regulatory asset amortization schedules.

Net Cost of Removal

As discussed in *Note 1*, we use the group depreciation method for the regulated business. This method is currently an acceptable method of accounting under accounting principles generally accepted in the United States of America and is widely used in the energy, transportation, and telecommunication industries.

Historically, under the group depreciation method, the anticipated costs of removing assets upon retirement were provided for over the life of those assets as a component of depreciation expense. However, effective January 1, 2003, we adopted SFAS No. 143, *Accounting for Asset Retirement Obligations.* In addition to providing the accounting requirements for recognizing an estimated liability for legal obligations associated with the retirement of tangible long-lived assets, SFAS No. 143 precludes the recognition of expected net future costs of removal as a component of depreciation expense or accumulated depreciation.

BGE is required by the Maryland PSC to use the group depreciation method, including cost of removal, under regulatory accounting. In accordance with SFAS No. 71, BGE continues to accrue for the future cost of removal for its regulated gas and electric assets by increasing its regulatory liability. This liability is relieved when actual removal costs are incurred.

Income Taxes Recoverable Through Future Rates (net)

As described in *Note 1*, income taxes recoverable through future rates are the portion of our net deferred income tax liability that is applicable to our regulated business, but has not been reflected in the rates we charge our customers. These income taxes represent the tax effect of temporary differences in depreciation and the allowance for equity funds used during construction, offset by differences in deferred tax rates and deferred taxes on deferred investment tax credits. We amortize these amounts as the temporary differences reverse.

Deferred Postretirement and Postemployment Benefit Costs

Deferred postretirement and postemployment benefit costs are the costs we recorded under SFAS No. 106, *Employers' Accounting for Postretirement Benefits Other Than Pensions,* and SFAS No. 112, *Employers' Accounting for Postemployment Benefits,* in excess of the costs we included in the rates we charge our customers. We began amortizing these costs over a 15-year period in 1998.

Deferred Environmental Costs

Deferred environmental costs are the estimated costs of investigating and cleaning up contaminated sites we own. We discuss this further in *Note 12*. We amortized $21.6 million of these costs (the amount we had incurred through October 1995) and are amortizing $6.4 million of these costs (the amount we incurred from November 1995 through June 2000) over 10-year periods in accordance with the Maryland PSC's orders. We applied for and received rate relief for an additional $5.4 million of clean-up costs incurred during the period from July 2000 through November 2005. These costs will be amortized over a 10-year period beginning in January 2006.

Deferred Fuel Costs

As described in *Note 1*, deferred fuel costs are the difference between our actual costs of purchased energy and our fuel rate revenues collected from customers. We reduce deferred fuel costs as we collect them from or refund them to our customers.

We exclude deferred fuel costs from rate base because their existence is relatively short-lived. These costs are recovered in the following year through our fuel rates.

Workforce Reduction Costs

The portions of the costs associated with our VSERP and workforce reduction programs that relate to BGE's gas business are deferred as regulatory assets in accordance with the Maryland PSC's orders in prior rate cases. As a result of a 2005 gas rate case, the remaining regulatory assets associated with workforce reductions totaling $7.3 million as of December 31, 2005 will be amortized over a 3-year period beginning January 2006. These remaining regulatory assets were previously amortized over 5-year periods beginning in January and February 2002.

7 Pension, Postretirement, Other Postemployment, and Employee Savings Plan Benefits

We offer pension, postretirement, other postemployment, and employee savings plan benefits. BGE employees participate in the benefit plans that we offer. We describe each of our plans separately below. Nine Mile Point offers its own pension, postretirement, other postemployment, and employee savings plan benefits to its employees. The benefits for Nine Mile Point are included in the tables beginning on the next page.

We use a December 31 measurement date for our pension, postretirement, other postemployment, and employee savings plans.

Pension Benefits

We sponsor several defined benefit pension plans for our employees. These include basic qualified plans that most employees participate in and several nonqualified plans that are available only to certain employees. A defined benefit plan specifies the amount of benefits a plan participant is to receive using information about the participant. Employees do not contribute to these plans. Generally, we calculate the benefits under these plans based on age, years of service, and pay.

Sometimes we amend the plans retroactively. These retroactive plan amendments require us to recalculate benefits related to participants' past service. We amortize the change in the benefit costs from these plan amendments on a straight-line basis over the average remaining service period of active employees.

We fund the qualified plans by contributing at least the minimum amount required under IRS regulations. We calculate the amount of funding using an actuarial method called the projected unit credit cost method. The assets in all of the plans at December 31, 2005 and 2004 were mostly marketable equity and fixed income securities.

Postretirement Benefits

We sponsor defined benefit postretirement health care and life insurance plans that cover the vast majority of our employees. Generally, we calculate the benefits under these plans based on age, years of service, and pension benefit levels or final base pay. We do not fund these plans.

For nearly all of the health care plans, retirees make contributions to cover a portion of the plan costs.

Contributions for employees who retire after June 30, 1992 are calculated based on age and years of service. The amount of retiree contributions increases based on expected increases in medical costs. For the life insurance plan, retirees do not make contributions to cover a portion of the plan costs.

Effective in 2002, we amended our postretirement medical plans for all subsidiaries other than Nine Mile Point. Our contributions for retiree medical coverage for future retirees that were under the age of 55 on January 1, 2002 are capped at the 2002 level. We also amended our plans to increase the Medicare eligible retirees' share of medical costs.

In 2003, the President signed into law the Medicare Prescription Drug Improvement and Modernization Act of 2003 (the Act). This legislation provides a prescription drug benefit for Medicare beneficiaries, a benefit that we provide to our Medicare eligible retirees. Our actuaries previously concluded that prescription drug benefits available under our postretirement medical plan are "actuarially equivalent" to Medicare Part D and thus qualify for the subsidy under the Act. In 2005, the Center for Medicare and Medicaid Services accepted our application to receive a tax reimbursement for eligible prescription drug costs. The expected subsidy will offset a portion of our share of the cost of the underlying postretirement prescription drug coverage. This legislation reduced our Accumulated Postretirement Benefit Obligation by $42.6 million at January 1, 2005 and our annual postretirement benefit expense in 2005 by $5.4 million. This subsidy is expected to reduce our estimated 2006 cash per capita medical costs from $3,289 to $2,694, or by 18%.

Additional Minimum Pension Liability Adjustment

Our pension accumulated benefit obligation has exceeded the fair value of our plan assets since 2001. At December 31, 2005 and 2004, our pension obligations were greater than the fair value of our plan assets for our qualified and our nonqualified pension plans as follows:

	Qualified Plans			
At December 31, 2005	Nine Mile	Other	Non-Qualified Plans	Total
		(In millions)		
Accumulated benefit obligation	**$ 127.1**	**$ 1,325.1**	**$ 56.3**	**$ 1,508.5**
Fair value of assets	**84.9**	**1,022.2**		**1,107.1**
Unfunded obligation	**$ 42.2**	**$ 302.9**	**$ 56.3**	**$ 401.4**

	Qualified Plans			
At December 31, 2004	Nine Mile	Other	Non-Qualified Plans	Total
		(In millions)		
Accumulated benefit obligation	$ 122.1	$ 1,185.9	$ 46.1	$ 1,354.1
Fair value of assets	78.6	1,005.8		1,084.4
Unfunded obligation	$ 43.5	$ 180.1	$ 46.1	$ 269.7

As required under SFAS No. 87, *Employers' Accounting for Pensions,* we recorded additional minimum pension liability adjustments as follows:

	Increase (Decrease)			
			Accumulated Other Comprehensive Loss	
	Pension Liability Adjustment	Intangible Asset *	Pre-tax	After-tax
		(In millions)		
Cumulative through 2003	$ 295.2	$ 46.7	$ (248.5)	$ (150.2)
2004	64.4	(6.1)	(70.5)	(42.6)
2005	121.4	(6.1)	(127.5)	(77.1)

		Increase (Decrease)		
Total	$ 481.0	$ 34.5	$ (446.5)	$ (269.9)

* *Included in "Other assets" in our Consolidated Balance Sheets.*

Obligations, Assets, and Funded Status

In June 2004, we assumed pension and postretirement benefit obligations for new employees in connection with the acquisition of the R.E. Ginna Nuclear Plant (Ginna). The sellers of Ginna transferred assets into our qualified plan trust. We discuss the Ginna acquisition further in *Note 15*.

As a result of a workforce reduction initiative in the generation business, pension and postretirement special termination benefits were recorded in December 2004. We discuss the workforce reduction initiative further in *Note 2*.

We show the change in the benefit obligations, plan assets, and funded status of the pension and postretirement benefit plans in the following tables.

	Pension Benefits		Postretirement Benefits	
	2005	2004	2005	2004
	(In millions)			
Change in benefit obligation				
Benefit obligation at January 1	**$ 1,513.2**	$ 1,326.0	**$ 423.2**	$ 430.8
Service cost	**44.8**	40.1	**7.6**	6.5
Interest cost	**83.9**	82.4	**23.8**	22.6
Plan participants' contributions			**7.4**	5.8
Actuarial loss (gain)	**143.6**	117.1	**35.6**	(17.2)
Ginna acquisition		40.5		6.1
Special termination benefits	**(0.4)**	2.4		1.2
Benefits paid (1)	**(106.5)**	(95.3)	**(37.2)**	(32.6)
Benefit obligation at December 31	**$ 1,678.6**	$ 1,513.2	**$ 460.4**	$ 423.2

(1) *Benefits paid include annuity payments, lump-sum distributions, and transfers to nonqualified deferred compensation plans.*

	Pension Benefits		Postretirement Benefits	
	2005	2004	2005	2004
	(In millions)			
Change in plan assets				
Fair value of plan assets at January 1	**$ 1,084.4**	$ 954.6	**$**	$
Actual return on plan assets	**76.2**	114.1		
Employer contribution	**53.0**	60.2	**29.8**	26.7
Plan participants' contributions			**7.4**	5.9
Ginna acquisition		50.8		
Benefits paid (1)	**(106.5)**	(95.3)	**(37.2)**	(32.6)
Fair value of plan assets at December 31	**$ 1,107.1**	$ 1,084.4	**$**	$

(1) Benefits paid include annuity payments, lump-sum distributions, and transfers to nonqualified deferred compensation plans.

At December 31,	Pension Benefits 2005	Pension Benefits 2004	Postretirement Benefits 2005	Postretirement Benefits 2004
	(In millions)			
Funded Status				
Funded Status	**$ (571.5)**	$ (428.8)	**$ (460.4)**	$ (423.2)
Unrecognized net actuarial loss	**618.9**	480.8	**150.8**	121.1
Unrecognized prior service cost	**32.2**	37.9	**(33.2)**	(36.7)
Unrecognized transition obligation			**14.9**	17.0
Pension liability adjustment	**(481.0)**	(359.6)		
Accrued benefit cost	**$ (401.4)**	$ (269.7)	**$ (327.9)**	$ (321.8)

Net Periodic Benefit Cost

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

Year Ended December 31,	2005	2004	2003
	(In millions)		
Components of net periodic pension benefit cost			
Service cost	**$ 44.8**	$ 40.1	$ 33.7
Interest cost	**83.9**	82.3	81.3
Expected return on plan assets	**(100.2)**	(97.9)	(95.0)
Amortization of unrecognized prior service cost	**5.7**	5.8	5.8
Recognized net actuarial loss	**25.1**	14.3	5.0
Amount capitalized as construction cost	**(7.4)**	(4.5)	(2.6)
Net periodic pension benefit cost (1)	**$ 51.9**	$ 40.1	$ 28.2

(1) *Net periodic pension benefit cost excludes SFAS No. 88 settlement charge of $4.4 million in 2005, SFAS No. 88 settlement charge of $2.8 million and termination benefits of $2.4 million in 2004, and SFAS No. 88 settlement charge of $2.8 million in 2003. BGE's portion of our net periodic pension benefit costs, excluding amount capitalized, was $15.0 million in 2005, $8.6 million in 2004, and $4.3 million in 2003. The vast majority of our retirees are BGE employees.*

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

Year Ended December 31,	2005	2004	2003
	(In millions)		
Components of net periodic postretirement benefit cost			
Service cost	**$ 7.6**	$ 6.5	$ 6.1
Interest cost	**23.8**	22.6	26.3
Amortization of transition obligation	**2.1**	2.1	2.1
Recognized net actuarial loss	**6.4**	3.1	5.8
Amortization of unrecognized prior service cost	**(3.5)**	(3.5)	(3.5)
Amount capitalized as construction cost	**(7.7)**	(7.0)	(8.8)
Net periodic postretirement benefit cost (1)	**$ 28.7**	$ 23.8	$ 28.0

(1)

Net periodic postretirement benefit cost excludes SFAS No. 106 termination benefits of $1.2 million in 2004. BGE's portion of our net periodic postretirement benefit cost, excluding amounts capitalized, was $17.4 million in 2005, $15.1 million in 2004, and $19.4 million in 2003.

Expected Cash Benefit Payments

The pension and postretirement benefits we expect to pay in each of the next five calendar years and in the aggregate for the subsequent five years are shown below. These estimated benefits are based on the same assumptions used to measure the benefit obligation at December 31, 2005, but includes benefits attributable to estimated future employee service.

		Postretirement Benefits		
	Pension Benefits*	Before Medicare Part D	Subsidy	After Medicare Part D
		(In millions)		
2006	$ 95.8	$ 27.4	$ (2.7)	$ 24.7
2007	90.3	30.4	(2.6)	27.8
2008	92.7	31.5	(2.8)	28.7
2009	96.6	32.4	(2.9)	29.5
2010	101.7	33.0	(3.0)	30.0
2011-2015	611.1	176.1	(17.0)	159.1

** Excludes transfers to nonqualified deferred compensation plans*

Assumptions

We made the assumptions below to calculate our pension and postretirement benefit obligations and periodic cost.

	Pension Benefits		Postretirement Benefits		Assumption Impacts
	2005	2004	2005	2004	Calculation of
Discount rate	**5.50%**	5.75%	**5.50%**	5.75%	Benefit Obligation and Periodic Cost
Expected return on plan assets	**9.0**	9.0	**N/A**	N/A	Periodic Cost
Rate of compensation increase	**4.0**	4.0	**4.0**	4.0	Benefit Obligation and Periodic Cost

Our 9.0% overall expected long-term rate of return on plan assets reflects our long-term investment strategy in terms of asset mix targets and expected returns for each asset class. Our discount rate is based on Moody's Aa long-term bond index. We periodically perform studies to ensure that this index is comparable to the use of a high quality bond portfolio whose maturities match our expected benefit payments. Effective in 2006, we reduced our assumed expected return on pension plan assets from 9.0% to 8.75% based on a fundamental analysis utilizing expected long-term returns applied to our targeted asset allocation.

Annual health care inflation rate assumptions also impact the calculation of our postretirement benefit obligation and periodic cost. We assumed the following health care inflation rates to produce average claims by year as shown below:

At December 31,	2005	2004
Next year	**9.0%**	10.0%
Following year	**8.0%**	9.0%
Ultimate trend rate	**5.0%**	5.0%
Year ultimate trend rate reached	**2010**	2010

A one-percent increase in the health care inflation rate from the assumed rates would increase the accumulated postretirement benefit obligation by approximately $36.4 million as of December 31, 2005 and would increase the combined service and interest costs of the postretirement benefit cost by approximately $2.4 million annually.

A one-percent decrease in the health care inflation rate from the assumed rates would decrease the accumulated postretirement benefit obligation by approximately $30.1 million as of December 31, 2005 and would decrease the combined service and interest costs of the postretirement benefit cost by approximately $1.9 million annually.

Qualified Pension Plan Assets

The asset allocations for our qualified pension plans were as follows:

At December 31,	2005	2004
Equity securities	**59%**	57%
Debt securities	**32**	33
Other	**9**	10
Total	**100%**	100%

The category "Other" primarily represents investments in financial limited partnerships. Our long-term pension plan investment strategy is to seek an asset mix of 53% equity, 35% fixed income, and 12% other investments. We rebalance our portfolio periodically when the sum of equity and other investments differs from 65% by three percentage points or more, we change an outside investment advisor, or we make contributions to the trust.

We determine expected return on plan assets using a market-related value of plan assets that recognizes asset gains and losses ratably over a five-year period.

Contributions and Benefit Payments

We contributed an additional $50 million to our qualified pension plans in March 2005, even though there was no IRS required minimum contribution in 2005. We expect to contribute $52 million to our pension plans in 2006, even though there is no required IRS minimum contribution for 2006. Our non-qualified pension plans and our postretirement benefit programs are not funded. We estimate that we will incur approximately $3 million in pension benefits for our non-qualified pension plans and approximately $25 million for retiree health and life insurance costs net of Medicare Part D during 2006.

Other Postemployment Benefits

We provide the following postemployment benefits:

- health and life insurance benefits to eligible employees determined to be disabled under our Disability Insurance Plan,
- income replacement payments for Nine Mile Point union-represented employees determined to be disabled, and

income replacement payments for other employees determined to be disabled before November 1995 (payments for employees determined to be disabled after that date are paid by an insurance company, and the cost is paid by employees).

The liability for these benefits totaled $54.7 million as of December 31, 2005 and $53.5 million as of December 31, 2004.

We assumed the discount rate for other postemployment benefits to be 5.25% in 2005 and 5.0% in 2004. This assumption impacts the calculation of our other postemployment benefit obligation and periodic cost.

Employee Savings Plan Benefits

We sponsor defined contribution savings plans that are offered to all eligible employees. The savings plans are qualified 401(k) plans under the Internal Revenue Code. In a defined contribution plan, the benefits a participant is to receive result from regular contributions to a participant account. Matching contributions to participant accounts are made under these plans. Matching contributions to these plans were:

$18.6 million, of which BGE contributed $5.1 million, in 2005,

$16.7 million, of which BGE contributed $4.7 million, in 2004, and

$14.1 million, of which BGE contributed $4.6 million, in 2003.

8 Credit Facilities and Short-Term Borrowings

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

Constellation Energy

Constellation Energy had committed bank lines of credit under four credit facilities of $3.6 billion at December 31, 2005 for short-term financial needs as follows:

- $200.0 million 364-day bilateral credit facility expiring in December 2006,
- $1.5 billion five-year revolving credit facility expiring in March 2010,
- $1.1 billion five-year revolving credit facility expiring in November 2010, and
- $750.0 million five-year revolving credit facility expiring in November 2010.

We enter into these facilities to ensure adequate liquidity to support our operations. Currently, we use the facilities to issue letters of credit primarily for our merchant energy business. Additionally, we can borrow directly from the banks or use the facilities to allow the issuance of commercial paper with the exception of the $200 million bilateral facility, which only supports letters of credit. We had $290.0 million of commercial paper outstanding at February 28, 2006.

These facilities can issue letters of credit up to approximately $3.6 billion. Letters of credit issued under all of our facilities totaled $2.5 billion at December 31, 2005 and $809.9 million at December 31, 2004. The increase in letters of credit issued is primarily due to changes in collateral requirements with counterparties as a result of higher commodity prices and the growth of our merchant energy business. Constellation Energy had no commercial paper outstanding at December 31, 2005 and 2004.

Merchant Energy Business

In 2005, our merchant energy business executed several short-term repurchase agreements that resulted in $0.7 million of net short-term borrowings which matured in January 2006.

BGE

BGE had no commercial paper outstanding at December 31, 2005 or 2004.

BGE continues to maintain $200.0 million in committed 364-day bilateral credit agreements, expiring May 2006 through November 2006. BGE can borrow directly from the banks or use the agreements to allow the issuance of commercial paper.

Other Nonregulated Businesses

Our other nonregulated businesses had no short-term borrowings outstanding at December 31, 2005 or 2004.

9 Long-Term Debt and Preference Stock

Long-term Debt

Long-term debt matures in one year or more from the date of issuance. We detail our long-term debt in our Consolidated Statements of Capitalization. As you read this section, it may be helpful to refer to those statements.

Constellation Energy

During 2004, we decided to continue our ownership in a synthetic fuel processing facility in South Carolina. We discuss this facility in more detail in *Note 10*. In connection with our decision to continue with our ownership in this facility, we are committed to making fixed payments until the end of 2007. Accordingly, during 2004, we recorded a liability of $39.3 million, net of discount related to imputed interest, in "Long-term debt" in our Consolidated Balance Sheets for these fixed payments. We used an imputed interest rate because there was no stated interest rate on these fixed payments. The imputed interest rate was calculated to be 3.47% and was based on our borrowing rate for a similar loan.

In connection with the sale of our international investments, we transferred $96.3 million of long-term debt to the buyers. We discuss the sale of this facility in more detail in *Note 2*.

BGE

BGE's First Refunding Mortgage Bonds

BGE's first refunding mortgage bonds are secured by a mortgage lien on all of its assets. The generating assets BGE transferred to subsidiaries of Constellation Energy also remain subject to the lien of BGE's mortgage, along with the stock of Safe Harbor Water Power Corporation and Constellation Enterprises, Inc.

BGE is required to make an annual sinking fund payment each August 1 to the mortgage trustee. The amount of the payment is equal to 1% of the highest principal amount of bonds outstanding during the preceding 12 months. The trustee uses these funds to retire bonds from any series through repurchases or calls for early redemption. However, the trustee cannot call the following bonds for early redemption:

$7^1/_2$% Series, due 2007

$6^5/_8$% Series, due 2008

In July 2005, BGE announced a partial call of $1.9 million principal amount of its Remarketed Floating Rate Series Bonds due September 1, 2006 in connection with its annual sinking fund. The redemption was made pursuant to the sinking fund provisions of BGE's mortgage. Bonds called were randomly selected by lot. Bonds called for the sinking fund were redeemed in part on August 26, 2005 at the sinking fund call price of 100% of principal amount, plus accrued interest from June 1, 2005 to, but not including, August 26, 2005.

BGE's Other Long-Term Debt

On July 1, 2000, BGE transferred $278.0 million of tax-exempt debt to our merchant energy business related to the transferred assets. At December 31, 2005, BGE remains contingently liable for the $269.8 million outstanding balance of this debt.

We show the weighted-average interest rates and maturity dates for BGE's fixed-rate medium-term notes outstanding at December 31, 2005 in the following table.

Series	Weighted-Average Interest Rate	Maturity Dates
B	8.63%	2006
D	6.70	2006
E	6.66	2006-2012
G	6.08	2008

Some of the medium-term notes include a "put option." These put options allow the holders to sell their notes back to BGE on the put option dates at a price equal to 100% of the principal amount. The following is a summary of medium-term notes with put options.

Series E Notes	Principal	Put Option Dates
	(In millions)	
6.75%, due 2012	$ 59.5	June 2007
6.75%, due 2012	25.0	June 2007
6.73%, due 2012	25.0	June 2007

BGE Deferrable Interest Subordinated Debentures

On November 21, 2003, BGE Capital Trust II (BGE Trust II), a Delaware statutory trust established by BGE, issued 10,000,000 Trust Preferred Securities for $250 million ($25 liquidation amount per preferred security) with a distribution rate of 6.20%.

BGE Trust II used the net proceeds from the issuance of common securities to BGE and the Trust Preferred Securities to purchase a series of 6.20% Deferrable Interest Subordinated Debentures due October 15, 2043 (6.20% debentures) from BGE in the aggregate principal amount of $257.7 million with the same terms as the Trust Preferred Securities. BGE Trust II must redeem the Trust Preferred Securities at $25 per preferred security plus accrued but unpaid distributions when the 6.20% debentures are paid at maturity or upon any earlier redemption. BGE has the option to redeem the 6.20% debentures at any time on or after November 21, 2008 or at any time when certain tax or other events occur.

BGE Trust II will use the interest paid on the 6.20% debentures to make distributions on the Trust Preferred Securities. The 6.20% debentures are the only assets of BGE Trust II.

BGE fully and unconditionally guarantees the Trust Preferred Securities based on its various obligations relating to the trust agreement, indentures, 6.20% debentures, and the preferred security guarantee agreement.

For the payment of dividends and in the event of liquidation of BGE, the 6.20% debentures are ranked prior to preference stock and common stock.

Revolving Credit Agreement

On December 18, 2001, one of our subsidiaries, District Chilled Water Partnership (ComfortLink) entered into a $25.0 million loan agreement with the Maryland Energy Financing Administration (MEFA). The terms of the loan exactly match the terms of variable rate, tax exempt bonds due December 1, 2031 issued by MEFA for ComfortLink to finance the cost of building a chilled water distribution system. The interest rate on this debt resets weekly. These bonds, and the corresponding loan, can be redeemed at any time at par plus accrued interest while under variable rates. The bonds can also be converted to a fixed rate at ComfortLink's option.

Debt Compliance and Covenants

The credit facilities of Constellation Energy and BGE discussed in *Note 8* have limited material adverse change clauses that only consider a material change in financial condition and are not directly affected by decreases in credit ratings. If these clauses are invoked, the lending institutions can decline to make new advances or issue new letters of credit, but cannot accelerate existing amounts outstanding. The long-term debt indentures of Constellation Energy and BGE do not contain material adverse change clauses or financial covenants.

Certain credit facilities of Constellation Energy contain a provision requiring Constellation Energy to maintain a ratio of debt to capitalization equal to or less than 65%. At December 31, 2005, the debt to capitalization ratio as defined in the credit agreements was 59%.

Certain credit agreements of BGE contain provisions requiring BGE to maintain a ratio of debt to capitalization equal to or less than 65%. At December 31, 2005, the debt to capitalization ratio for BGE as defined in these credit agreements was 45%. At December 31, 2005, no amounts were outstanding under these agreements.

Failure by Constellation Energy, or BGE, to comply with these covenants could result in the acceleration of the maturity of the debt outstanding under these facilities. The credit facilities of Constellation Energy contain usual and customary cross-default provisions that apply to defaults on debt by Constellation Energy and certain subsidiaries over a specified threshold. Certain BGE credit facilities also contain usual and customary cross-default provisions that apply to defaults on debt by BGE over a specified threshold. The indentures pursuant to which BGE has issued and outstanding mortgage bonds and subordinated debentures provide that a default under any debt instrument issued under the relevant indenture may cause a default of all debt outstanding under such indenture.

Constellation Energy also provides credit support to Calvert Cliffs, Ginna, and Nine Mile Point to ensure these plants have funds to meet expenses and obligations to safely operate and maintain the plants.

Maturities of Long-Term Debt

Our long-term borrowings mature on the following schedule (includes sinking fund requirements):

Year	**Constellation Energy**	**Nonregulated Businesses**	**BGE**
		(In millions)	
2006	$	$ 21.7	$ 444.6
2007	600.0	21.3	122.0
2008		6.1	294.8
2009	500.0	1.4	11.5
2010			
Thereafter	1,949.1	307.0	589.1
Total long-term debt at December 31, 2005	$ 3,049.1	$ 357.5	$ 1,462.0

At December 31, 2005, we had long-term loans totaling $282.3 million that mature after 2005, which contain certain put options under which lenders could potentially require us to repay the debt prior to maturity, or which are periodically remarketed and could require repayment following any unsuccessful remarketing. As a result of these provisions, at December 31, 2005, $25.0 million is classified as current portion of long-term debt at BGE.

Weighted-Average Interest Rates for Variable Rate Debt

Our weighted-average interest rates for variable rate debt were:

At December 31,	**2005**	**2004**
Nonregulated Businesses (including Constellation Energy)		
Loans under credit agreements	**4.71%**	3.58%
Tax-exempt debt transferred from BGE	**2.77%**	1.54%
BGE		
Remarketed floating rate series mortgage bonds	**3.14%**	1.39%

As discussed in *Note 13* we have entered into interest rate swaps relating to $450 million of our fixed-rate debt.

Preference Stock

Each series of BGE preference stock has no voting power, except for the following:

the preference stock has one vote per share on any charter amendment which would create or authorize any shares of stock ranking prior to or on a parity with the preference stock as to either dividends or distribution of assets, or which would substantially adversely affect the contract rights, as expressly set forth in BGE's charter, of the preference stock, each of which requires the affirmative vote of two-thirds of all the shares of preference stock outstanding; and whenever BGE fails to pay full dividends on the preference stock and such failure continues for one year, the preference stock shall have one vote per share on all matters, until and unless such dividends shall have been paid in full. Upon liquidation, the holders of the preference stock of each series outstanding are entitled to receive the par amount of their shares and an amount equal to the unpaid accrued dividends.

10 Taxes

The components of income tax expense are as follows:

Year Ended December 31,	2005	2004	2003
	(Dollar amounts in millions)		
Income Taxes			
Current			
Federal	**$ 45.2**	$ 22.5	$ 145.6
State	**33.4**	21.6	29.3
Current taxes charged to expense	**78.6**	44.1	174.9
Deferred			
Federal	**116.6**	95.8	67.6
State	**16.0**	24.2	15.4
Deferred taxes charged to expense	**132.6**	120.0	83.0
Investment tax credit adjustments	**(7.1)**	(7.2)	(7.3)
Income taxes per Consolidated Statements of Income	**$ 204.1**	$ 156.9	$ 250.6

Certain prior year amounts have been reclassified to conform to the current year's presentation of discontinued operations.

Total income taxes are different from the amount that would be computed by applying the statutory Federal income tax rate of 35% to book income before income taxes as follows:

Reconciliation of Income Taxes Computed at Statutory Federal Rate to Total Income Taxes	2005	2004	2003
Income from continuing opera- tions before income taxes (excluding BGE preference stock dividends)	**$ 824.0**	$ 736.9	$ 720.5
Statutory federal income tax rate	**35%**	35%	35%
Income taxes computed at statu- tory federal rate	**288.4**	257.9	252.2
Increases (decreases) in income taxes due to			
Depreciation differences not nor- malized on regulated activities	**3.8**	4.0	4.1
Amortization of deferred investment tax credits	**(7.1)**	(7.2)	(7.3)
Synthetic fuel tax credits flowed through to income*	**(114.9)**	(123.2)	(35.0)
State income taxes, net of federal income tax benefit	**32.8**	29.3	30.9
Nondeductible merger-related transaction costs	**5.3**		
Other	**(4.2)**	(3.9)	5.7
Total income taxes	**$ 204.1**	$ 156.9	$ 250.6
Effective income tax rate	**24.8%**	21.3%	34.8%

Certain prior year amounts have been reclassified to conform to the current year's presentation of discontinued operations.

** 2004 includes credits associated with 2003 production at our South Carolina facility that were recognized in the second quarter of 2004 upon receipt of a favorable Private Letter Ruling from the IRS.*

BGE's effective tax rate was 38.8% in 2005, 38.1% in 2004, and 39.2% in 2003. The difference between BGE's effective tax rate and the 35% statutory federal income tax rate is primarily related to Maryland corporate income taxes at an effective rate of 4.55%, which is net of the related federal income tax benefit.

The major components of our net deferred income tax liability are as follows:

	Constellation Energy		BGE	
At December 31,	**2005**	**2004**	**2005**	**2004**
		(In millions)		
Deferred Income Taxes				
Deferred tax liabilities				
Net property, plant and equipment	**$ 1,539.3**	$ 1,478.6	**$ 526.7**	$ 522.2
Qualified nuclear decommissioning trust funds	**332.8**	317.6		
Regulatory assets, net	**85.5**	93.0	**85.5**	93.0
Mark-to- market energy assets and liabilities, net	**141.2**	83.7		
Other	**112.7**	124.1	**61.3**	64.8
Total deferred tax liabilities	**2,211.5**	2,097.0	**673.5**	680.0
Deferred tax assets				
Asset retirement obligation	**353.6**	327.3		
Accrued pension and post- employment benefit costs	**243.8**	184.3	**41.4**	40.1
Financial investments and hedging instruments	**144.7**	34.5		
Deferred investment tax credits	**24.2**	26.9	**5.3**	5.9
Reduction of investments	**7.4**	23.6		
Other	**105.6**	102.1	**8.3**	15.7
Total deferred tax assets	**879.3**	698.7	**55.0**	61.7
Total deferred tax liability, net	**1,332.2**	1,398.3	**618.5**	618.3
Current portion of deferred tax liability, net (BGE's portion recorded in accrued expenses and other)	**151.4**	95.0	**9.6**	10.3
Long-term portion of deferred tax liability, net	**$ 1,180.8**	$ 1,303.3	**$ 608.9**	$ 608.0

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

Synthetic Fuel Tax Credits

Our merchant energy business has investments in facilities that manufacture solid synthetic fuel produced from coal as defined under the Internal Revenue Code (IRC) for which we can claim tax credits on our Federal income tax return through 2007. We recognize the tax benefit of these credits in our Consolidated Statements of Income when we believe it is highly probable that the credits will be sustained. The synthetic fuel process involves combining coal material with a chemical reagent to create a significant chemical change. A taxpayer may request a private letter ruling from the IRS to support its position that the synthetic fuel produced undergoes a significant chemical change and thus qualifies for synthetic fuel tax credits.

We own a minority ownership in four synthetic fuel facilities located in Virginia and West Virginia. These facilities have received private letter rulings from the IRS. In January 2004, the IRS concluded its examination of the partnership that owns these facilities for the tax years 1998 through 2001 and the IRS did not disallow any of the previously recognized synthetic fuel credits. During the second quarter of 2004, we received final written notice of the resolution of the examination from the IRS.

In 2003, we purchased 99% ownership in a South Carolina facility that produces synthetic fuel. We did not recognize in our Consolidated Statements of Income the tax benefit of $35.9 million for credits claimed on our South Carolina facility in 2003 pending receipt of a favorable private letter ruling. In 2004, we received a favorable private letter ruling. We believe receipt of the private letter ruling provides reasonable assurance that it is highly probable that the credits will be sustained. Therefore, we recognized the tax benefit of $35.9 million in our Consolidated Statements of Income during 2004.

While we believe the production and sale of synthetic fuel from all of our synthetic fuel facilities meet the conditions to qualify for tax credits under the IRC, we cannot predict the timing or outcome of any future challenge by the IRS, legislative or regulatory action, or the ultimate impact of such events on the synthetic fuel tax credits that we have claimed to date, but the impact could be material to our financial results.

11 Leases

There are two types of leases operating and capital. Capital leases qualify as sales or purchases of property and are reported in our Consolidated Balance Sheets. Our capital leases are not material in amount. All other leases are operating leases and are reported in our Consolidated Statements of Income. We expense all lease payments associated with our regulated business. Lease expense and future minimum payments for long-term, noncancelable, operating leases are not material to BGE's financial results. We present information about our operating leases below.

Outgoing Lease Payments

We, as lessee, lease some facilities and equipment. The lease agreements expire on various dates and have various renewal options. We also enter into certain power purchase agreements which are accounted for as operating leases. Under these agreements, we are required to make fixed capacity payments, as well as variable payments based on actual output of the plants. We record these payments as "Fuel and purchased energy expenses" in our Consolidated Statements of Income. We exclude from our future minimum lease payments table the variable payments related to the output of the plant due to the contingency associated with these payments.

We recognized expense related to our operating leases as follows:

	Fuel and purchased energy expenses	Operating expenses	Total
		(In millions)	
2005	$ 103.2	$ 24.8	$ 128.0
2004	11.0	23.1	34.1
2003	5.1	17.6	22.7

At December 31, 2005, we owed future minimum payments for long-term, noncancelable, operating leases as follows:

Year	Power Purchase Agreements	Other	Total
		(In millions)	
2006	$ 137.2	$ 22.4	$ 159.6
2007	135.5	17.2	152.7
2008	94.8	15.1	109.9
2009	35.3	14.1	49.4
2010	31.4	13.0	44.4
Thereafter	249.3	76.2	325.5
Total future minimum lease payments	$ 683.5	$ 158.0	$ 841.5

12 Commitments, Guarantees, and Contingencies

Commitments

We have made substantial commitments in connection with our merchant energy, regulated electric and gas, and other nonregulated businesses. These commitments relate to:

- purchase of electric generating capacity and energy, procurement and delivery of fuels, and

long-term service agreements, capital for construction programs, and other.

Our merchant energy business enters into various long-term contracts for the procurement and delivery of fuels to supply our generating plant requirements. In most cases, our contracts contain provisions for price escalations, minimum purchase levels, and other financial commitments. These contracts expire in various years between 2006 and 2017. In addition, our merchant energy business enters into long-term contracts for the capacity and transmission rights for the delivery of energy to meet our physical obligations to our customers. These contracts expire in various years between 2006 and 2015.

Our merchant energy business also has committed to long-term service agreements and other purchase commitments for our plants.

Our regulated electric business enters into various long-term contracts for the procurement of electricity. These contracts expire in 2006. The cost of power under these contracts is recoverable under the POLR agreement reached with the Maryland PSC, as discussed in *Note 1,* and therefore are excluded from the table on the next page.

Our regulated gas business enters into various long-term contracts for the procurement, transportation, and storage of gas. Our regulated gas business has gas transportation and storage contracts that expire between 2006 and 2028. These contracts are recoverable under BGE's gas cost adjustment clause discussed in *Note 1,* and therefore are excluded from the table on the next page.

Our other nonregulated businesses have committed to gas purchases and to contributions of additional capital for construction programs and joint ventures in which they have an interest.

We have also committed to long-term service agreements and other obligations related to our information technology systems.

At December 31, 2005, we estimate our future obligations to be as follows:

	Payments				
	2006	2007-2008	2009-2010	Thereafter	Total
	(In millions)				
Merchant Energy					
Purchased capacity and energy	$ 697.6	$ 891.5	$ 308.5	$ 162.7	$ 2,060.3
Fuel and transportation	2,360.3	1,054.6	436.2	575.5	4,426.6
Long-term service agreements, capital, and other	66.3	78.9	44.6	144.8	334.6
Total merchant energy	3,124.2	2,025.0	789.3	883.0	6,821.5
Corporate and Other:					
Long-term service agreements, capital, and other	32.0	9.7	1.9	0.6	44.2
Regulated:					
Purchase obligations and other	42.0	49.1		0.2	91.3
Total future obligations	$ 3,198.2	$ 2,083.8	$ 791.2	$ 883.8	$ 6,957.0

Pending Merger with FPL Group, Inc.

In connection with the merger agreement with FPL Group, there are certain contingencies relating to potential cash payments. We discuss these contingencies in *Note 14* and *Note 15*.

Long-Term Power Sales Contracts

We enter into long-term power sales contracts in connection with our load-serving activities. We also enter into long-term power sales contracts associated with certain of our power plants. Our load-serving power sales contracts extend for terms through 2017 and provide for the sale of energy to electricity distribution utilities and certain retail customers. Our power sales contracts associated with our power plants extend for terms into 2014 and provide for the sale of all or a portion of the actual output of certain of our power plants. All long-term contracts were executed at pricing that approximated market rates, including profit margin, at the time of execution.

Guarantees

The terms of our guarantees are as follows:

	Expiration				
	2006	2007-2008	2009-2010	Thereafter	Total
			(In millions)		
Competitive supply	$ 5,514.1	$ 546.1	$ 251.6	$ 1,956.7	$ 8,268.5
Other	5.6	13.3	1.8	1,262.0	1,282.7
Total guarantees	$ 5,519.7	$ 559.4	$ 253.4	$ 3,218.7	$ 9,551.2

Expiration

At December 31, 2005, Constellation Energy had a total of $9,551.2 million guarantees outstanding related to loans, credit facilities, and contractual performance of certain of its subsidiaries as described below. These guarantees do not represent our incremental obligations, and we do not expect to fund the full amount under these guarantees.

Constellation Energy guaranteed $8,268.5 million on behalf of our subsidiaries for competitive supply activities. These guarantees are put into place in order to allow our subsidiaries the flexibility needed to conduct business with counterparties without having to post other forms of collateral. While the face amount of these guarantees is $8,268.5 million, our calculated fair value of obligations covered by these guarantees was $2,830.5 million at December 31, 2005. If the parent company was required to fund these subsidiary obligations, the total amount based on December 31, 2005 market prices would be $2,830.5 million. The recorded fair value of obligations in our Consolidated Balance Sheets for guarantees was $1,333.6 million at December 31, 2005.

Constellation Energy guaranteed $932.3 million primarily on behalf of our nuclear generating facilities mostly due to nuclear insurance and for credit support to ensure these plants have funds to meet expenses and obligations to safely operate and maintain the plants.

Constellation Energy guaranteed $59.6 million on behalf of our other nonregulated businesses primarily for loans and performance bonds of which $25.0 million was recorded in our Consolidated Balance Sheets at December 31, 2005.

Our merchant energy business guaranteed $19.2 million for loans and other performance guarantees related to certain power projects in which we have an investment.

Our other nonregulated business guaranteed $8.3 million primarily for performance bonds.

BGE guaranteed two-thirds of certain debt of Safe Harbor Water Power Corporation, an unconsolidated investment. At December 31, 2005, Safe Harbor Water Power Corporation had outstanding debt of $20.0 million. The maximum amount of BGE's guarantee is $13.3 million.

BGE guaranteed the Trust Preferred Securities of $250.0 million of BGE Trust II, an unconsolidated investment, as discussed in *Note 9*.

The total fair value of the obligations for our guarantees recorded in our Consolidated Balance Sheets at December 31, 2005 was $1,358.6 million and not the $9.6 billion of total guarantees. We assess the risk of having to perform under these guarantees to be minimal.

Environmental Matters

Solid and Hazardous Waste

The Environmental Protection Agency (EPA) and several state agencies have notified us that we are considered a potentially responsible party with respect to the clean-up of certain environmentally contaminated sites. We cannot estimate the final clean-up costs for all of these sites, but the current estimated costs for, and current status of, each site is described in more detail below.

Metal Bank

In 1997, the EPA, under the Comprehensive Environmental Response, Compensation and Liability Act ("Superfund"), issued a Record of Decision (ROD) for the proposed clean-up at the Metal Bank of America site, a metal reclaimer in Philadelphia. We had previously recorded a liability in our Consolidated Balance Sheets for BGE's 15.47% share of probable clean-up costs. Based on current settlement negotiations among the EPA and the potentially responsible parties involved at the site, we do not believe we will incur clean-up costs in excess of the amount recorded as a liability. The EPA and the potentially responsible parties, including BGE, are currently pursuing claims against Metal Bank of America for an equitable share of expected site remediation costs.

68th Street Dump

In 1999, the EPA proposed to add the 68th Street Dump in Baltimore, Maryland to the Superfund National Priorities List ("NPL"), which is its list of sites targeted for clean-up and enforcement, and sent a general notice letter to BGE and 19 other parties identifying them as potentially liable parties at the site. In March 2004, we and other potentially responsible parties formed the 68th Street Coalition, which has entered into consent order negotiations with the EPA to investigate clean-up options for the site under the Superfund Alternative Sites Program. While negotiations under this program are ongoing, the 68th Street Dump will not be placed on the NPL. At this stage, it is not possible to predict the outcome of those discussions or our share of the liability. However, the costs could have a material effect on our financial results.

Kane and Lombard

The EPA issued its ROD for the Kane and Lombard Drum site located in Baltimore, Maryland on September 30, 2003. The ROD specifies the clean-up plan for the site, consisting of enhanced reductive dechlorination, a soil management plan, and institutional controls. In July 2004, the EPA issued a Special Notice/Demand Letter to BGE and three other potentially responsible parties regarding implementation of the remedy and in November 2005 issued an order, expected to become effective in the first quarter of 2006, requiring cleanup of the site by those parties as well as 15 other parties. The total clean-up costs are estimated to be approximately $10 million. We estimate our current share of site-related costs to be 11.1% of the total. In December 2002, we recorded a liability in our Consolidated Balance Sheets for our share of the clean-up costs that we believe is probable. Our final share of the $10 million has not been determined and it may vary from the current estimate.

Spring Gardens

In December 1996, BGE signed a consent order with the Maryland Department of the Environment that requires it to implement remedial action plans for contamination at and around the Spring Gardens site, located in Baltimore, Maryland. The Spring Gardens site was once used to manufacture gas from coal and oil. Based on the remedial action plans, BGE estimates its probable clean-up costs will total $47 million. BGE has recorded these costs as a liability in its Consolidated Balance Sheets and has deferred these costs, net of accumulated amortization and amounts it recovered from insurance companies, as a regulatory asset. Based on the results of studies at this site, it is reasonably possible that additional costs could exceed the amount BGE has recognized by approximately $14 million. Through December 31, 2005, BGE has spent approximately $40 million for remediation at this site.

BGE also has investigated other small sites where gas was manufactured in the past. We do not expect the clean-up costs of the remaining smaller sites to have a material effect on our financial results.

Air Quality

In late July 2005, we received two Notices of Violation (NOVs) from the Placer County Air Pollution Control District, Placer County California (District) alleging that the Rio Bravo Rocklin facility located in Lincoln, California had violated certain District air emission regulations. We have a combined 50% ownership interest in the partnership which owns the Rio Bravo Rocklin facility. The NOVs allege a total of 38 violations between January 2003 and March 2005 of either the facility's air permit or federal, state, and county air emission standards related to NO_x, carbon monoxide, and particulate emissions, as well as violations of certain monitoring and reporting requirements during that time period. The maximum civil penalties for the alleged violations range from $10,000 to $40,000 per violation. Management of the Rio Bravo Rocklin facility is currently evaluating the allegations in the NOVs; and therefore, it is not possible to determine the actual liability, if any, of the partnership that owns the Rio Bravo Rocklin facility.

Litigation

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

Western Power Markets

City of Tacoma v. AEP, et al., The City of Tacoma, on June 7, 2004, in the U.S. District Court, Western District of Washington, filed a complaint against over 60 companies, including Constellation Energy Commodities Group, Inc. (CCG). The complaint alleges that the defendants engaged in manipulation of electricity markets resulting in prices for power in the western power markets that were substantially above what market prices would have been in the absence of the alleged unlawful contracts, combinations and conspiracy in violation of Section 1 of the Sherman Act. The complaint further alleges that the total amount of damages is unknown, but is estimated to exceed $175 million. On February 11, 2005, the Court granted the defendants' motion to dismiss the action based on the Court's lack of jurisdiction over the claims in question. The plaintiff has appealed the dismissal of the action to the Ninth Circuit Court of Appeals. We believe that we have meritorious defenses to this action and intend to defend against it vigorously. However, we cannot predict the timing, or outcome, of this case, or its possible effect on our financial results.

Wholesale Electricity Antitrust Cases

In connection with a proceeding originally filed in March 2002, Reliant Energy Services (Reliant) and certain of its affiliates filed to join CCG and 29 other companies as cross-defendants in a proceeding entitled *Wholesale Electricity Antitrust Cases I and II*. Motions to dismiss the claims filed against the original defendants were recently granted and the original defendants have dismissed the cross claims filed against CCG and the 29 other cross defendants. Therefore, the claims against CCG in this action are resolved.

Mercury

Beginning in September 2002, BGE, Constellation Energy, and several other defendants have been involved in numerous actions filed in the Circuit Court for Baltimore City, Maryland alleging mercury poisoning from several sources, including coal plants formerly owned by BGE. The plants are now owned by a subsidiary of Constellation Energy. In addition to BGE and Constellation Energy, approximately 11 other defendants, consisting of pharmaceutical companies, manufacturers of vaccines, and manufacturers of Thimerosal have been sued. Approximately 70 cases, involving claims related to approximately 132 children, have been filed to date, with each claimant seeking $20 million in compensatory damages, plus punitive damages, from us.

In a ruling applicable to all but six of the cases, involving claims related to approximately 49 children, the Circuit Court for Baltimore City dismissed with prejudice all claims against BGE and Constellation Energy and entered into a stay of the proceedings as they relate to other defendants. Plaintiffs may attempt to pursue appeals of the rulings in favor of BGE and Constellation Energy once the cases are finally concluded as to all defendants. We believe that we have meritorious defenses and intend to defend the actions vigorously. However, we cannot predict the timing, or outcome, of these cases, or their possible effect on our, or BGE's, financial results.

Asbestos

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

Approximately 509 individuals who were never employees of BGE have pending claims each seeking several million dollars in compensatory and punitive damages. Cross-claims and third-party claims brought by other defendants may also be filed against BGE in these actions. To date, most asbestos claims against us have been dismissed or resolved without any payment and a small minority have been resolved for amounts that were not material to our financial results. The remaining claims are currently pending in state courts in Maryland and Pennsylvania.

BGE does not know the specific facts necessary to estimate its potential liability for these claims. The specific facts BGE does not know include:

- the identity of BGE's facilities at which the plaintiffs allegedly worked as contractors,
- the names of the plaintiffs' employers,
- the dates on which and the places where the exposure allegedly occurred, and

the facts and circumstances relating to the alleged exposure.

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

There has been no activity related to certain third-party claims filed against BGE by Pittsburgh Corning Corp. (PCC) since PCC filed bankruptcy in April 2000. In addition, we do not believe that any amounts payable under claims made by PCC would have a material effect on our, or BGE's, financial results.

Canadian Environmental Class Action

Christopher M. Robinson, et. al. v. Ontario Power Generation Inc., et. al. On June 30, 2005, three individuals filed a class action in the Superior Court of Justice in Ontario, Canada against 21 companies, including Constellation Power Source Generation, Inc. (CPSG), one of our subsidiaries. The complaint alleges claims on behalf of residents of Ontario, Canada that have allegedly suffered adverse health effects as a result of emissions of sulfur dioxide, nitrogen oxide, and particulate matter from approximately 60 different coal-fired power plants operating in Ontario, Michigan, Ohio, Pennsylvania, Kentucky, and West Virginia. The complaint was not served on the defendants as required by December 31, 2005, and thus, this action is effectively dismissed without prejudice.

Storage of Spent Nuclear Fuel

The Nuclear Waste Policy Act of 1982 (NWPA) required the federal government through the Department of Energy (DOE), to develop a repository for, and disposal of, spent nuclear fuel and high-level radioactive waste. The NWPA and our contracts with the DOE required the DOE to begin taking possession of spent nuclear fuel generated by nuclear generating units no later than January 31, 1998. The DOE has stated that it will not meet that obligation until 2010 at the earliest.

This delay has required that we undertake additional actions related to on-site fuel storage at Calvert Cliffs and Nine Mile Point, including the installation of on-site dry fuel storage capacity at Calvert Cliffs. In January 2004, we filed a complaint against the federal government in the United States Court of Federal Claims seeking to recover damages caused by the DOE's failure to meet its contractual obligation to begin disposing of spent nuclear fuel by January 31, 1998. The cases are currently stayed, pending litigation in other related cases.

In connection with our purchase of Ginna, all of Rochester Gas & Electric Corporation's (RG&E) rights and obligations related to recovery of damages from the DOE were assigned to us. However, we have an obligation to reimburse RG&E for up to the first $10 million in recovered damages.

Nuclear Insurance

We maintain nuclear insurance coverage for Calvert Cliffs, Nine Mile Point, and Ginna in four program areas: liability, worker radiation, property, and accidental outage. These policies contain certain industry standard exclusions, including, but not limited to, ordinary wear and tear, and war.

In November 2002, the President signed into law the Terrorism Risk Insurance Act ("TRIA") of 2002. Under the TRIA, property and casualty insurance companies are required to offer insurance for losses resulting from Certified acts of terrorism. Certified acts of terrorism are determined by the Secretary of State and Attorney General and primarily are based upon the occurrence of significant acts of international terrorism. Our nuclear property and accidental outage insurance programs, as discussed later in this section, provide coverage for Certified acts of terrorism.

If there were an accident or an extended outage at any unit of Calvert Cliffs, Nine Mile Point or Ginna, it could have a substantial adverse impact on our financial results.

Nuclear Liability Insurance

Pursuant to the Price-Anderson Act, we are required to insure against public liability claims resulting from nuclear incidents to the full limit of public liability. This limit of liability consists of the maximum available commercial insurance of $300 million and mandatory participation in an industry-wide retrospective premium assessment program. The retrospective premium assessment is $100.6 million per reactor, increasing the total amount of insurance for public liability to approximately $10.8 billion. Under the retrospective assessment program, we can be assessed up to $503 million per incident at any commercial reactor in the country, payable at no more than $75 million per incident per year. This assessment also applies in excess of our worker radiation claims insurance and is subject to inflation and state premium taxes. Claims resulting from non-certified acts of terrorism are limited to the commercial insurance discussed above, regardless of the number of nuclear plants affected. In addition, the U.S. Congress could impose additional revenue-raising measures to pay claims.

Worker Radiation Claims Insurance

We participate in the American Nuclear Insurers Master Worker Program that provides coverage for worker tort claims filed for radiation injuries. Effective January 1, 1998, this program was modified to provide coverage to all workers whose nuclear-related employment began on or after the commencement date of reactor operations. Waiving the right to make additional claims under the old policy was a condition for coverage under the new policy. We describe the old and new policies below:

Nuclear worker claims reported on or after January 1, 1998 are covered by a new insurance policy with a single industry aggregate limit of $300 million for radiation injury claims against all those insured by this policy.

All nuclear worker claims reported prior to January 1, 1998 are still covered by the old policy. Insureds under the old policies, with no current operations, are not required to purchase the new policy described on the previous page, and may still make claims against the old policies through 2007. If radiation injury claims under these old policies exceed the policy reserves, all policyholders could be retroactively assessed, with our share being up to $6.3 million.

The sellers of Nine Mile Point retain the liabilities for existing and potential claims that occurred prior to November 7, 2001. In addition, the Long Island Power Authority, which continues to own 18% of Unit 2 at Nine Mile Point, is obligated to assume its pro rata share of any liabilities for retrospective premiums and other premium assessments. RG&E, the seller of Ginna, retains the liabilities for existing and potential claims that occurred prior to June 10, 2004. If claims under these policies exceed the coverage limits, the provisions of the Price-Anderson Act would apply.

Nuclear Property Insurance

Our policies provide $500 million in primary coverage at each nuclear plant Calvert Cliffs, Nine Mile Point, and Ginna. In addition, we maintain $1.77 billion of excess coverage at Ginna and $2.25 billion in excess coverage under a blanket excess program offered by the industry mutual insurer at both Calvert Cliffs and Nine Mile Point. Under the blanket excess policy, Calvert Cliffs and Nine Mile Point share $1.0 billion of the total $2.25 billion of excess property coverage. Therefore, in the unlikely event of two full limit property damage losses at Calvert Cliffs and Nine Mile Point, we would recover $4.5 billion instead of $5.5 billion. This coverage currently is purchased through the industry mutual insurance company. If accidents at plants insured by the mutual insurance company cause a shortfall of funds, all policyholders could be assessed, with our share being up to $92.3 million.

Losses resulting from non-certified acts of terrorism are covered as a common occurrence, meaning that if non-certified terrorist acts occur against one or more commercial nuclear power plants insured by our nuclear property insurance company within a 12-month period, they would be treated as one event and the owners of the plants where the acts occurred would share one full limit of liability (currently $3.24 billion).

Accidental Nuclear Outage Insurance

Our policies provide indemnification on a weekly basis for losses resulting from an accidental outage of a nuclear unit. Coverage begins after a 12-week deductible period and continues at 100% of the weekly indemnity limit for 52 weeks and then 80% of the weekly indemnity limit for the next 110 weeks. Our coverage is up to $490.0 million per unit at Calvert Cliffs and Ginna, $420.0 million for Unit 1 of Nine Mile Point, and $401.8 million for Unit 2 of Nine Mile Point. This amount can be reduced by up to $98.0 million per unit at Calvert Cliffs and $84.0 million for Nine Mile Point if an outage of more than one unit is caused by a single insured physical damage loss.

Non-Nuclear Property Insurance

Our conventional property insurance provides coverage of $1.0 billion per occurrence for Certified acts of terrorism as defined under the Terrorism Risk Insurance Act of 2002. Certified acts of terrorism are determined by the Secretary of State and Attorney General of the United States and primarily are based upon the occurrence of significant acts of international terrorism. Our conventional property insurance program also provides coverage for non-certified acts of terrorism up to an annual aggregate limit of $1.0 billion. If a terrorist act occurs at any of our facilities, it could have a significant adverse impact on our financial results.

13 Hedging Activities and Fair Value of Financial Instruments

SFAS No. 133 Hedging Activities

We are exposed to market risk, including changes in interest rates and the impact of market fluctuations in the price and transportation costs of electricity, natural gas, and other commodities.

Interest Rates

We use interest rate swaps to manage our interest rate exposures associated with new debt issuances and to optimize the mix of fixed and floating-rate debt. The swaps used to manage our exposure prior to the issuance of new debt are designated as cash-flow hedges under SFAS No. 133, with the effective portion of gains and losses, net of associated deferred income tax effects, recorded in "Accumulated other comprehensive income" in our Consolidated Statements of Common Shareholders' Equity and Comprehensive Income and Consolidated Statements of Capitalization, in anticipation of planned financing transactions. We reclassify gains and losses on the hedges from "Accumulated other comprehensive income" into "Interest expense" in our Consolidated Statements of Income during the periods in which the interest payments being hedged occur.

The swaps used to optimize the mix of fixed and floating-rate debt are designated as fair value hedges under SFAS No. 133. We record any gains or losses on swaps that qualify for fair value hedge accounting treatment, as well as changes in the fair value of the debt being hedged, in "Interest expense," and we record any changes in fair value of the swaps and the debt in "Risk management assets and liabilities" and "Long-term debt" in our Consolidated Balance Sheets. In addition, we record the difference between interest on hedged fixed-rate debt and floating-rate swaps in "Interest expense" in the periods that the swaps settle.

"Accumulated other comprehensive income" includes net unrealized pre-tax gains on interest rate cash-flow hedges totaling $15.4 million at December 31, 2005 and $18.3 million at December 31, 2004. We expect to reclassify $2.9 million of pre-tax net gains on these cash-flow hedges from "Accumulated other comprehensive income" into "Interest expense" during the next twelve months. We had no hedge ineffectiveness on these swaps.

During 2004, to optimize the mix of fixed and floating-rate debt, we entered into interest rate swaps qualifying as fair value hedges relating to $450 million of our fixed-rate debt maturing in 2012 and 2015, and converted this notional amount of debt to floating-rate. The fair value of these hedges was an unrealized loss of $0.9 million at December 31, 2005 and was recorded as an increase in our "Risk management liabilities" and a decrease in our "Long-term debt." The fair value of these hedges was an unrealized gain of $13.3 million at December 31, 2004 and was recorded as an increase in our "Risk management assets" and "Long-term debt." We have not recognized any hedge ineffectiveness on these interest rate swaps.

Commodity Prices

Our merchant energy business uses a variety of derivative and non-derivative instruments to manage the commodity price risk of our competitive supply activities and our electric generation facilities, including power sales, fuel and energy purchases, gas purchased for resale, emission credits, weather risk, and the market risk of outages. In order to manage these risks, we may enter into fixed-price derivative or non-derivative contracts to hedge the variability in future cash flows from forecasted sales of energy and purchases of fuel and energy. The objectives for entering into such hedges include:

- fixing the price for a portion of anticipated future electricity sales at a level that provides an acceptable return on our electric generation operations,
- fixing the price of a portion of anticipated fuel purchases for the operation of our power plants,
- fixing the price for a portion of anticipated energy purchases to supply our load-serving customers, and
- fixing the price for a portion of anticipated sales of natural gas to customers.

The portion of forecasted transactions hedged may vary based upon management's assessment of market, weather, operational, and other factors.

At December 31, 2005, our merchant energy business had designated certain fixed-price forward contracts as cash-flow hedges of forecasted sales of energy and forecasted purchases of fuel and energy for the years 2006 through 2015 under SFAS No. 133. Our merchant energy business had net unrealized pre-tax losses on these cash-flow hedges recorded in "Accumulated other comprehensive income" of $517.1 million at December 31, 2005 and $103.8 million at December 31, 2004. We expect to reclassify $434.7 million of net pre-tax gains on cash-flow hedges from "Accumulated other comprehensive income" into earnings during the next twelve months based on the market prices at December 31, 2005. However, the actual amount reclassified into earnings could vary from the amounts recorded at December 31, 2005, due to future changes in market prices.

Additionally, for cash-flow hedges settled by physical delivery of the underlying commodity, "Reclassification of net gains on hedging instruments from OCI to net income" represents the fair value of those derivatives, which is realized through gross settlement at the contract price. In 2005, we recognized $19.4 million of pre-tax losses in earnings related to cash-flow hedge ineffectiveness. During 2005, we terminated a contract previously designated as a cash-flow hedge. The forecasted transaction originally hedged is no longer probable and as a result we recognized a pre-tax loss of $6.1 million.

Our merchant energy business also enters into natural gas storage contracts under which the gas in storage qualifies for fair value hedge accounting treatment under SFAS No. 133. During 2005, we had unrealized pre-tax gains of $2.3 million and unrealized pre-tax losses of $4.5 million due to hedge ineffectiveness, and the resulting pre-tax net loss of $2.2 million was recognized into earnings during 2005. We record changes in fair value of these hedges as a component of "Fuel and purchased energy expenses" in our Consolidated Statements of Income.

Regulated Gas Business

BGE uses basis swaps in the winter months (November through March) to hedge its price risk associated with natural gas purchases under its market-based rates incentive mechanism and under its off-system gas sales program. BGE also uses fixed-to-floating and floating-to-fixed swaps to hedge its price risk associated with its off-system gas sales. The fixed portion represents a specific dollar amount that BGE will pay or receive, and the floating portion represents a fluctuating amount based on a published index that BGE will receive or pay. BGE's regulated gas business internal guidelines do not permit the use of swap agreements for any purpose other than to hedge price risk.

Fair Value of Financial Instruments

The fair value of a financial instrument represents the amount at which the instrument could be exchanged in a current transaction between willing parties, other than in a forced sale or liquidation. Significant differences can occur between the fair value and carrying amount of financial instruments that are recorded at historical amounts. We use the following methods and assumptions for estimating fair value disclosures for financial instruments:

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

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

At December 31,	2005		2004	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
		(In millions)		
Investments and other assets Constellation Energy	**$ 1,362.1**	**$ 1,362.3**	$ 1,190.0	$ 1,191.2
Fixed-rate long-term debt:				
Constellation Energy	**4,169.3**	**4,379.3**	4,468.5	4,979.7
BGE	**1,364.6**	**1,376.4**	1,404.3	1,468.2
Variable-rate long-term debt:				
Constellation Energy	**699.3**	**699.3**	835.6	835.6
BGE	**97.4**	**97.4**	99.3	99.3

14 Stock-Based Compensation

Under our long-term incentive plans, we granted stock options, performance and service-based restricted stock, performance-based units, and equity to officers, key employees, and members of the Board of Directors. Under the plans, we can grant up to a total of 18,000,000 shares. At December 31, 2005, we had stock options, restricted stock, and stock unit grants outstanding as discussed below. We may issue new shares, reuse forfeited shares, or buy shares in the market in order to deliver shares to employees for our equity grants. BGE officers and key employees participate in our stock-based compensation plans. The expense recognized by BGE in 2005, 2004, and 2003 was not material to BGE's financial results.

Certain awards accounted for as equity grants under our long-term incentive plans provide for accelerated vesting and cash settlement in the event of a change in control. If the pending merger with FPL Group becomes probable of occurring, we will be required to account for these awards as liabilities under SFAS No. 123R and remeasure them at fair value each reporting period until they are settled. We discuss the pending merger with FPL Group in more detail in *Note 15*.

Non-Qualified Stock Options

Options are generally granted with an exercise price equal to the market value of the common stock at the date of grant, become vested over a period up to three years (expense recognized in tranches), and expire ten years from the date of grant. The fair value of our stock-based awards were estimated as of the date of grant using the Black-Scholes option pricing model based on the following weighted-average assumptions:

	2005	2004	2003
Risk-free interest rate	**4.10%**	3.15%	2.92%
Expected life (in years)	**2.9***	5.0	5.0
Expected market price volatility factor	**21.3%**	23.7%	32.0%
Expected dividend yield	**3.0%**	3.0%	3.3%

**Includes 2.0 million fully vested options granted in December 2005 that will be cancelled upon a change in control if our pending merger with FPL Group is consummated for which an expected life of one year was used to value the grant. Excluding this grant, we used a weighted-average expected life assumption of 5 years for 2005 grants.*

We use the historical data related to stock option exercises in order to estimate the expected life of our stock options. We also use historical data in order to estimate the volatility factor (measured on a daily basis) for a period equal to the duration of the expected life of option awards. We believe that the use of historical data to estimate these factors provides a reasonable basis for our assumptions. The risk-free interest rate for the periods within the expected life of the option is based on the U.S Treasury yield curve in effect and the expected dividend yield is based on our current estimate for dividend payout at the time of grant. We disclose the pro-forma effect on net income and earnings per share for the periods prior to adoption of SFAS No. 123R in *Note 1*.

Summarized information for our stock option grants is as follows:

	2005		2004		2003	
	Shares	Weighted-Average Exercise Price	Shares	Weighted-Average Exercise Price	Shares	Weighted-Average Exercise Price
			(Shares in thousands)			
Outstanding, beginning of year	**7,365**	**$ 31.62**	7,117	$ 29.53	6,081	$ 29.65
Granted with exercise prices:						
At fair market value	**3,840**	**54.94**	1,640	39.60	1,485	29.24
Greater than fair market value					9	28.53
Total granted	**3,840**	**54.94**	1,640	39.60	1,494	29.24

	2005			2004			2003		
Exercised	**(3,935)**		**29.32**	(834)		28.49	(267)		27.92
Forfeited/expired	**(98)**		**42.19**	(558)		33.09	(191)		33.28
Outstanding, end of year	**7,172**	**$**	**45.24**	7,365	$	31.62	7,117	$	29.53
Exercisable, end of year	**4,022**	**$**	**45.31**	3,844	$	29.99	3,169	$	29.89
Weighted-average fair value per share of options granted with exercise prices:									
At fair market value		**$**	**7.13**		$	7.22		$	6.80
Greater than fair market value									5.56

The total intrinsic value realized by participants on options exercised during the years ended December 31, 2005 was $109.8 million, 2004 was $10.5 million, and 2003 was $1.8 million. We realized a tax benefit of $43.4 million in 2005, $4.2 million in 2004, and $0.7 million in 2003 on the intrinsic value realized by participants on option exercises. In addition, we received cash of $35.3 million in 2005, $23.7 million in 2004, and $7.5 million in 2003 for the exercise price associated with stock option exercises. The total fair value of shares that vested in 2005 was $232.0 million, in 2004 was $59.0 million, and in 2003 was $69.4 million. As of December 31, 2005, we had $10.4 million of unrecognized compensation cost related to the unvested portion of outstanding stock option awards expected to be recognized within a two-year period.

The following table summarizes additional information about stock options outstanding at December 31, 2005 (stock options in thousands):

	Outstanding		Exercisable		
Range of Exercise Prices	**Stock Options**	**Aggregate Intrinsic Value**	**Stock Options**	**Aggregate Intrinsic Value**	**Weighted-Average Remaining Contractual Life**
		(In millions)		*(In millions)*	*(In years)*
20.$ 00 $30.00	887	$ 25.6	538	$ 15.6	7.2
30.$ 00 $40.00	2,416	51.4	1,481	34.6	6.7
40.$ 00 $50.00	66	1.1	22	0.4	8.3
50.$ 00 $60.00	3,803	11.1	1,981		7.7
	7,172	$ 89.2	4,022	$ 50.6	

Restricted Stock Awards

In addition to stock options, we issue common stock based on meeting certain service goals. This stock vests to participants at various times ranging from one to five years if the service goals are met. In accordance with SFAS No. 123R, we account for our service-based awards as equity awards, whereby we recognize the value of the market price of the underlying stock on the date of grant to compensation expense over the service period either ratably or in tranches (depending if the award has cliff or graded vesting).

We recorded compensation expense related to our restricted stock awards of $28.2 million in 2005, $17.0 million in 2004, and $16.4 million in 2003. Summarized share information for our restricted stock awards is as follows:

	2005	2004	2003
		(Shares in thousands)	
Outstanding, beginning of year	**1,223**	752	314
Granted	**485**	1,002	555
Released to participants	**(359)**	(467)	(109)
Canceled	**(77)**	(64)	(8)
Outstanding, end of year	**1,272**	1,223	752
Weighted-average fair value of restricted stock granted	**$ 51.23**	$ 38.83	$ 30.53
Total fair value of shares for which restriction has lapsed (in millions)	**$ 19.0**	$ 18.8	$ 3.8

As of December 31, 2005, we had $16.7 million of unrecognized compensation cost related to the unvested portion of outstanding restricted stock awards expected to be recognized within a two-year period. At December 31, 2005, we have recorded in "Common shareholders' equity" approximately $21 million for the unvested portion of service-based restricted stock granted from 2001 until 2005 to officers and other employees that is contingently redeemable in cash upon a change in control.

Performance-Based Units

In accordance with SFAS No. 123R, we recognize compensation expense ratably for our performance-based awards, which are classified as liability awards, for which the fair value of the award is remeasured at each reporting period. Each unit is equivalent to $1 in value and cliff vests at the end of a three-year service and performance period. The level of payout is based on the achievement of certain performance goals at the end of the three-year period and at least 50% of any payouts will be settled in cash, and the other 50% may be settled in either stock or cash at our discretion. We recorded compensation expense of $7.0 million in 2005, $2.9 million in 2004, and no expense in 2003 for these awards. No awards were settled during the year, and as of December 31, 2005 we had $12.2 million of unrecognized compensation cost related to the unvested portion of outstanding performance-based unit awards expected to be recognized within a two-year period.

Equity-Based Grants

We recorded compensation expense of $0.5 million in 2005, $0.5 million in 2004, and $0.4 million in 2003 related to equity-based grants to members of the Board of Directors.

15 Merger and Acquisitions

Pending Merger with FPL Group, Inc.

On December 18, 2005, Constellation Energy entered into an Agreement and Plan of Merger with FPL Group. Immediately prior to the completion of the merger, each share of Constellation Energy will be split into 1.444 shares of Constellation Energy common stock and cash will be paid in lieu of fractional shares. At closing, each share of common stock of FPL Group issued and outstanding will be exchanged for 1.0 share of common stock of Constellation Energy. As a result of the stock split and merger and assuming no conversion of any other convertible securities of FPL Group or Constellation Energy, it is expected that Constellation Energy stockholders will own approximately 40% of the combined company's outstanding shares of common stock immediately following the merger and FPL Group stockholders will own approximately 60% of the common stock of the combined company's outstanding shares of common stock.

The merger agreement contains certain termination rights for both Constellation Energy and FPL Group and under specified circumstances Constellation Energy may be required to pay FPL Group a termination fee of $425 million and FPL Group may be required to pay Constellation Energy a termination fee of $650 million. In addition, under specified circumstances each party may be obligated to reimburse the other party for up to $40 million of expenses, which would reduce the amount of any required termination fee payable by that party. Furthermore, under certain limited circumstances a party whose board of directors has changed or withdrawn its recommendation in favor of the merger may be required to pay the other party $100 million. These payments would also reduce the amount of any other required termination fee payable by that party.

The merger agreement has been unanimously approved by both companies' boards of directors but completion of the merger is contingent upon, among other things, the approval of the transaction by shareholders of both companies and receipt of required regulatory approvals. The companies anticipate obtaining all necessary approvals before the end of 2006.

The merger will be accounted for as a purchase under accounting principles generally accepted in the United States of America. Under the purchase method of accounting, the assets and liabilities of Constellation Energy will be recorded, as of the completion of the merger, at their respective fair values and added to those of FPL Group. The reported financial condition and results of operations of Constellation Energy after completion of the merger will reflect Constellation Energy's balances and results after completion of the merger, but will not be restated retroactively to reflect the historical financial position or results of operations of Constellation Energy.

In 2005, we expensed $17.0 million, of which BGE recorded $5.4 million, of external costs incurred prior to the execution of the merger agreement. We estimate our total transaction costs will be approximately $40 million.

Acquisition of Cogenex

In April 2005, we acquired Cogenex Corporation from Alliant Energy Corporation. We include Cogenex with our other nonregulated businesses and have included their results in our consolidated financial statements since the date of acquisition. Cogenex is a North American energy services firm providing consulting and technology solutions to industrial, institutional, and governmental customers. We acquired 100% ownership of Cogenex for $35.2 million. We acquired cash of $14.4 million as part of the purchase.

Our preliminary purchase price allocation for the net assets acquired is as follows:

At April 1, 2005

		(In millions)
Cash	$	14.4
Other Current Assets		11.3
Total Current Assets		25.7
Net Property, Plant and Equipment		
Other Assets		36.0
Total Assets Acquired		61.7
Current Liabilities		(7.3)
Deferred Credits and Other Liabilities		(19.2)

At April 1, 2005		
Net Assets Acquired	$	35.2

Currently, the purchase price remains subject to certain adjustments, which could impact our purchase price allocation.

We believe that the pro-forma impact of the Cogenex acquisition would not have been material to our results of operations in 2005, 2004, and 2003.

Acquisition of Working Interests in Gas Producing Fields

In June 2005, we acquired working interests in gas producing fields in Texas and Alabama for approximately $211 million in cash and the assumption of below-market natural gas swaps and other liabilities totaling approximately $18 million. At the time of acquisition, these working interests had independently estimated proved reserves of approximately 216 billion cubic feet equivalent. The Texas asset acquisition was for approximately a 70% working interest and the Alabama asset acquisition was for a 100% working interest. We accounted for this transaction as an asset acquisition and include these working interests in our merchant energy business segment.

Acquisition of Ginna

On June 10, 2004, we completed our purchase of the Ginna nuclear facility, which is located in Ontario, New York from RG&E. Ginna consists of a 498 megawatt reactor that entered service in 1970 and is licensed to operate until 2029.

We purchased 100 percent of Ginna for $457.3 million including direct costs associated with the acquisition, of which $430.0 million was paid in cash at closing and the remaining

$27.3 million was paid during the second half of 2004. RG&E also transferred to us $200.8 million in decommissioning funds.

We will sell 90 percent of Ginna's output back to RG&E at an average price of nearly $44 per megawatt-hour until June 2014 under a unit contingent power purchase agreement (if the output is not available because the plant is not operating, there is no requirement to provide output from other sources). The acquisition of Ginna was immediately accretive to earnings.

We accounted for this transaction as an asset acquisition and included Ginna in our merchant energy business segment. Our purchase price allocation for the net assets acquired is as follows:

At June 10, 2004

		(In millions)
Current Assets	$	27.9
Nuclear Decommissioning Trust Fund		200.8
Nuclear Fuel		14.5
Net Property, Plant and Equipment		382.8
Intangible Assets (details below)		38.8
Other Assets		124.0
Total Assets Acquired		788.8
Current Liabilities		(20.8)
Asset Retirement Obligations		(177.3)
Deferred Credits and Other Liabilities		(133.4)
Net Assets Acquired	$	457.3

The intangible assets acquired consist of the following:

Description		**Amount**	**Weighted-Average Useful Life**
		(In millions)	***(In years)***
Operating procedures and manuals	$	26.1	25
Permits and licenses		8.5	25
Software		4.2	5
Total intangible assets	$	38.8	

Acquisition of Blackhawk Energy Services and Kaztex Energy Management

On October 22, 2003, we completed our purchase of Blackhawk Energy Services (Blackhawk) and Kaztex Energy Management (Kaztex). We include Blackhawk and Kaztex, part of our retail gas operation, in our merchant energy business segment and have included their results in our consolidated financial statements since the date of acquisition. Blackhawk and Kaztex are providers of natural gas and electricity services.

On an unaudited pro-forma basis, had the acquisition of Blackhawk and Kaztex occurred on the first day of 2003, our nonregulated revenues and total revenues would have been as follows:

Year Ended December 31,		**2003**
		(In millions)
Nonregulated revenues		
As reported	$	6,819.9
Pro-forma		7,174.8

Year Ended December 31,	**2003**
Total revenues	
As reported	9,454.1
Pro-forma	9,809.0

We believe that the pro-forma impact on "Income before cumulative effect of change in accounting principle," "Net income," and "Earnings per common share" would not have been material had the acquisition of Blackhawk and Kaztex occurred on the first day of the year presented.

16 Related Party Transactions BGE

Income Statement

BGE provides standard offer service to those customers that do not choose an alternate supplier. Our wholesale marketing and risk management operation provided BGE with the energy and capacity required to meet its commercial and industrial standard offer service obligations through June 30, 2004 and provides the energy and capacity required to meet its residential standard offer service obligations through June 30, 2006. Bidding to supply BGE's standard offer service to commercial and industrial customers beyond June 30, 2004, and to residential customers beyond June 30, 2006, will continue to occur from time to time through a competitive bidding process approved by the Maryland PSC. Our wholesale marketing and risk management operation is supplying a portion of BGE's standard offer service obligation to commercial and industrial customers.

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

Year Ended December 31,	**2005**	**2004**	**2003**
		(In millions)	
Electricity purchased for resale expenses	**$ 805.9**	$ 948.9	$ 1,023.4

In addition, Constellation Energy charges BGE for the costs of certain corporate functions. Certain costs are directly assigned to BGE. We allocate other corporate function costs based on a total percentage of expected use by BGE. We believe this method of allocation is reasonable and approximates the cost BGE would have incurred as an unaffiliated entity.

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

Year ended December 31,	**2005**	**2004**	**2003**
		(In millions)	
Charges to BGE	**$ 130.3**	$ 99.8	$ 84.0

Balance Sheet

BGE participates in a cash pool under a Master Demand Note agreement with Constellation Energy. Under this arrangement, participating subsidiaries may invest in or borrow from the pool at market interest rates. Constellation Energy administers the pool and invests excess cash in short-term investments or issues commercial paper to manage consolidated cash requirements. Under this arrangement, BGE had borrowed $3.2 million at December 31, 2005 and had invested $127.9 million at December 31, 2004.

BGE's Consolidated Balance Sheets include intercompany amounts related to corporate functions performed at the Constellation Energy holding company, BGE's purchases to meet its standard offer service obligation, BGE's charges to Constellation Energy and its nonregulated affiliates for certain services it provides them, and the participation of BGE's employees in the Constellation Energy pension plan.

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

17 Quarterly Financial Data (Unaudited)

Our quarterly financial information has not been audited but, in management's opinion, includes all adjustments necessary for a fair statement. Our business is seasonal in nature with the peak sales periods generally occurring during the summer and winter months. Accordingly, comparisons among quarters of a year may not represent overall trends and changes in operations.

2005 Quarterly Data Constellation Energy

	Revenues	Income from Operations	Income from Continuing Operations and Before Cumulative Effects of Changes in Accounting Principles	Earnings Applicable to Common Stock	Earnings Per Share from Continuing Operations and Before Cumulative Effects of Changes in Accounting Principles-Diluted	Earnings Per Share of Common Stock-Diluted
	(In millions, except per share amounts)					
Quarter Ended						
March 31*	$ 3,572.0	$ 221.9	$ 118.6	$ 120.7	$ 0.66	$ 0.68
June 30*	3,478.5	209.8	117.8	121.7	0.66	0.68
September 30	4,922.4	317.0	184.1	185.5	1.02	1.03
December 31	5,159.1	309.4	186.2	195.2	1.04	1.09
Year Ended						
December 31	$ 17,132.0	$ 1,058.1	$ 606.7	$ 623.1	$ 3.38	$ 3.47

2005 Quarterly Data BGE

	Revenues	Income from Operations	Earnings Applicable to Common Stock
	(In millions)		
Quarter Ended			
March 31	$ 857.3	$ 143.7	$ 71.0
June 30	610.3	64.4	23.6
September 30	742.7	94.9	42.4
December 31	799.0	93.5	38.8
Year Ended			
December 31	$ 3,009.3	$ 396.5	$ 175.8

The sum of the quarterly earnings per share amounts may not equal the total for the year due to the effects of rounding and dilution as a result of issuing common shares during the year.

First quarter results include:

- a $1.7 million gain after-tax for the discontinued operations related to our other nonregulated international investments, and
- a $0.4 million gain after-tax for the discontinued operations related to our Oleander facility.

Second quarter results include:

- a $2.6 million gain after-tax for the discontinued operations related to our Oleander facility, and
- a $1.2 million gain after-tax income for discontinued operations related to our other nonregulated international investments.

Third quarter results include:

- workforce reduction costs totaling $2.3 million after-tax, and
- a $1.6 million gain after-tax for discontinued operations related to our other nonregulated international investments.

Fourth quarter results include:

- a $16.1 million gain after-tax for discontinued operations related to our other nonregulated international investments,
- merger related transaction costs totaling $15.6 million after-tax, of which BGE recorded $5.0 million after-tax,
- a $7.4 million after-tax loss for the cumulative effect of adopting FIN 47,
- workforce reduction costs totaling $0.4 million after-tax, and
- a $0.2 million after-tax gain for the cumulative effect of adopting SFAS No. 123R.

We discuss these items in *Note 2*.

** Due to the reclassification of our other nonregulated international investments to discontinued operations, we have reclassified certain amounts previously reported in our first and second quarter Form 10-Qs. The following is a reconciliation of amounts previously reported to amounts currently presented for those items.*

For the quarter ended	***March 31, 2005***			***June 30, 2005***		
	As Reported	**Discontinued Operations**	**Reclassified**	**As Reported**	**Discontinued Operations**	**Reclassified**
			(In millions, except per share amounts)			
Revenues	**$ 3,629.8**	**$ (57.8)**	**$ 3,572.0**	**$ 3,548.8**	**$ (70.3)**	**$ 3,478.5**
Income from Operations	**230.8**	**(8.9)**	**221.9**	**218.3**	**(8.5)**	**209.8**
Income from Continuing Operations and Before Cumulative Effects of Changes in Accounting Principles	**120.3**	**(1.7)**	**118.6**	**119.0**	**(1.2)**	**117.8**
Earnings Per Share from Continuing Operations and Before Cumulative Effects of Changes in Accounting Principles Diluted	**0.67**	**(0.01)**	**0.66**	**0.66**		**0.66**

2004 Quarterly Data Constellation Energy

	Revenues	Income from Operations	Income from Continuing Operations	Earnings Applicable to Common Stock	Earnings Per Share from Continuing Operations-Diluted	Earnings Per Share of Common Stock-Diluted
	(In millions, except per share amounts)					
Quarter Ended						
March 31*	$ 2,976.0	$ 224.7	$ 109.1	$ 66.2	$ 0.64	$ 0.39
June 30*	2,730.8	182.8	126.7	128.2	0.75	0.76
September 30	3,358.8	382.2	204.8	210.4	1.16	1.19
December 31	3,220.8	235.5	126.2	134.9	0.71	0.76
Year Ended						
December 31	$ 12,286.4	$ 1,025.2	$ 566.8	$ 539.7	$ 3.28	$ 3.12

2004 Quarterly Data BGE

	Revenues	Income from Operations	Earnings Applicable to Common Stock
	(In millions)		
Quarter Ended			
March 31	$ 803.9	$ 149.8	$ 72.7
June 30	589.8	65.6	21.9
September 30	657.3	77.1	28.1
December 31	673.7	78.9	30.4
Year Ended			
December 31	$ 2,724.7	$ 371.4	$ 153.1

The sum of the quarterly earnings per share amounts may not equal the total for the year due to the effects of rounding and dilution as a result of issuing common shares during the year.

First quarter results include:

a $46.3 million loss after-tax for the discontinued operations of our Hawaiian geothermal facility,

a $2.2 million gain after-tax for the discontinued operations of our Oleander facility, and

a $1.2 million gain after-tax for the discontinued operations of our other nonregulated international investments.

Second quarter results include:

a recognition of 2003 synthetic fuel tax credits of $35.9 million after-tax,

a $2.7 million loss after-tax for the discontinued operations of our Hawaiian geothermal facility,

a $2.7 million gain after-tax for the discontinued operations of our Oleander facility, and

a $1.5 million gain after-tax for the discontinued operations of our other nonregulated international investments.

Third quarter results include:

a $0.2 million loss after-tax for the discontinued operations of our Hawaiian geothermal facility,

a $4.6 million gain after-tax for the discontinued operations of our Oleander facility, and

a $1.2 million gain after-tax for the discontinued operations of our other nonregulated international investments.

Fourth quarter results include:

workforce reduction costs totaling $5.9 million after-tax,

a $5.5 million gain after-tax for discontinued operations of our other nonregulated international investments,

a $3.1 million gain after-tax for discontinued operations of our Oleander facility, and

a $0.1 million gain after-tax for the discontinued operations of our Hawaiian geothermal facility.

We discuss these items in *Note 2*.

** Due to the reclassification of our other nonregulated international investments to discontinued operations, we have reclassified certain amounts previously reported in our first and second quarter Form 10-Qs. The following is a reconciliation of amounts previously reported to amounts currently presented for those items.*

For the quarter ended	**March 31, 2004**			**June 30, 2004**		
	As Reported	**Discontinued Operations**	**Reclassified**	**As Reported**	**Discontinued Operations**	**Reclassified**
	(In millions, except per share amounts)					
Revenues	$ 3,029.6	$ (53.6)	$ 2,976.0	$ 2,787.3	$ (56.5)	$ 2,730.8
Income from Operations	232.3	(7.6)	224.7	191.9	(9.1)	182.8
Income from Continuing Operations and Before Cumulative Effects of Changes in Accounting Principles	110.3	(1.2)	109.1	128.2	(1.5)	126.7
Earnings Per Share from Continuing Operations and Before Cumulative Effects of Changes in Accounting Principles Diluted	0.65	(0.01)	0.64	0.76	(0.01)	0.75

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

The principal executive officers and principal financial officer of both Constellation Energy and BGE have evaluated the effectiveness of the disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")) as of December 31, 2005 (the "Evaluation Date"). Based on such evaluation, such officers have concluded that, as of the Evaluation Date, Constellation Energy's and BGE's disclosure controls and procedures are effective.

Internal Control Over Financial Reporting

Constellation Energy maintains a system of internal control over financial reporting as defined in Exchange Act Rule 13a-15(f). Constellation Energy's Management Report on Internal Control Over Financial Reporting is included in *Item 8. Financial Statements and Supplementary Data* included in this report. As BGE is not an accelerated filer as defined in Exchange Act Rule 12b-2, it is not required to provide a report of management on the effectiveness of its internal control over financial reporting as of December 31, 2005, but will be required to do so as of December 31, 2007.

Changes in Internal Control

During the quarter ended December 31, 2005, there has been no change in either Constellation Energy's or BGE's internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) that has materially affected, or is reasonably likely to materially affect, either Constellation Energy's or BGE's internal control over financial reporting.

Item 9B. Other Information

None.

PART III

BGE meets the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K for a reduced disclosure format. Accordingly, all items in this section related to BGE are not presented.

Item 10. Directors and Executive Officers of the Registrant

The information required by this item with respect to directors will be either set forth under *Election of Constellation Energy Directors* in the Proxy Statement and incorporated herein by reference or set forth in an amendment to this Form 10-K.

The information required by this item with respect to executive officers of Constellation Energy Group, pursuant to instruction 3 of paragraph (b) of Item 401 of Regulation S-K, is set forth following Item 4 of Part I of this Form 10-K under *Executive Officers of the Registrant*.

Item 11. Executive Compensation

The information required by this item will be either set forth under *Directors' Compensation*, *Executive Compensation*, *Common Stock Performance Graph* and *Report of Compensation Committee on Executive Compensation* in the Proxy Statement and incorporated herein by reference or set forth in an amendment to this Form 10-K.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Shareholder Matters

The additional information required by this item will be either set forth under *Security Ownership* in the Proxy Statement and incorporated herein by reference or set forth in an amendment to this Form 10-K.

Equity Compensation Plan Information

The following table reflects our equity compensation plan information as of December 31, 2005:

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants, and rights	(b) Weighted-average exercise price of outstanding options, warrants, and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in item (a))
	(In thousands)		*(In thousands)*
Equity compensation plans approved by security holders	5,100	$ 47.66	2,688
Equity compensation plans not approved by security holders	2,072	$ 39.29	1,007
Total	7,172	$ 45.24	3,695

The plans that do not require shareholder approval are the Constellation Energy Group, Inc. 2002 Senior Management Long-Term Incentive Plan (Designated as Exhibit No. 10(v)) and the Constellation Energy Group, Inc. Management Long-Term Incentive Plan (Designated as Exhibit No. 10(w)). A brief description of the material features of each of these plans is set forth on the next page.

2002 Senior Management Long-Term Incentive Plan

The 2002 Senior Management Long-Term Incentive Plan was effective May 24, 2002. Grants under the plan may be made to employees who are officers of Constellation Energy or hold senior management level or key employee positions with Constellation Energy or its subsidiaries. Under the plan, the Board of Constellation Energy has authorized the issuance of up to 4,000,000 shares of Constellation Energy common stock in connection with the grant of stock options, performance and service-based restricted stock and restricted stock units, performance units, stock appreciation rights, dividend equivalents and other equity awards. Any shares covered by an award that is forfeited or canceled, expires or is settled in cash, including the settlement of tax withholding obligations using shares, will become available for issuance under the plan. Shares delivered under the plan may be authorized and unissued shares, shares held in treasury or shares purchased on the open market in accordance with the applicable securities laws. Restricted stock, restricted stock unit, and performance unit award payouts will be accelerated and stock options and stock appreciation rights gains will be paid in cash in the event of a change in control, as defined in the plan. The plan is administered by Constellation Energy's Chief Executive Officer.

Management Long-Term Incentive Plan

The Management Long-Term Incentive Plan was effective February 1, 1998. Grants under the plan may be made to employees of Constellation Energy who hold a management level position and other employees of Constellation Energy and its subsidiaries as may be designated by Constellation Energy's Chief Executive Officer. Under the plan, the Board of Constellation Energy has authorized the issuance of up to 3,000,000 shares of Constellation Energy common stock in connection with the grant of stock options, performance and service-based restricted stock and restricted stock units, performance units, stock appreciation rights and dividend equivalents. The number of shares available for issuance under the plan includes shares subject to awards that have lapsed or terminated. Shares delivered under the plan may be authorized and unissued shares, shares held in treasury or shares purchased on the open market in accordance with applicable securities laws. Restricted stock, restricted stock unit, and performance unit award payouts will be accelerated and stock options and stock appreciation rights will become fully exercisable in the event of a change in control, as defined by the plan. The plan is administered by Constellation Energy's Chief Executive Officer.

Item 13. Certain Relationships and Related Transactions

The additional information required by this item will be either set forth under *Certain Relationships and Related Transactions* in the Proxy Statement and incorporated herein by reference or set forth in an amendment to this Form 10-K.

Item 14. Principal Accountant Fees and Services

The information required by this item will be either set forth under *Ratification of Appointment of PricewaterhouseCoopers LLP as Independent Registered Public Accounting Firm for 2006* in the Proxy Statement and incorporated herein by reference or set forth in an amendment to this Form 10-K.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) The following documents are filed as a part of this Report:

1. Financial Statements:
Reports of Independent Registered Public Accounting Firm dated February 22, 2006 of PricewaterhouseCoopers LLP
Consolidated Statements of Income Constellation Energy Group for three years ended December 31, 2005
Consolidated Balance Sheets Constellation Energy Group at December 31, 2005 and December 31, 2004
Consolidated Statements of Cash Flows Constellation Energy Group for three years ended December 31, 2005
Consolidated Statements of Common Shareholders' Equity and Comprehensive Income Constellation Energy Group for three years ended December 31, 2005
Consolidated Statements of Capitalization Constellation Energy Group at December 31, 2005 and December 31, 2004
Consolidated Statements of Income Baltimore Gas and Electric Company for three years ended December 31, 2005
Consolidated Statements of Comprehensive Income Baltimore Gas and Electric Company for three years ended December 31, 2005
Consolidated Balance Sheets Baltimore Gas and Electric Company at December 31, 2005 and December 31, 2004
Consolidated Statements of Cash Flows Baltimore Gas and Electric Company for three years ended December 31, 2005
Notes to Consolidated Financial Statements

2. Financial Statement Schedules:
Schedule II Valuation and Qualifying Accounts
Schedules other than Schedule II are omitted as not applicable or not required.

3. Exhibits Required by Item 601 of Regulation S-K.

Exhibit Number	
*2	Agreement and Plan of Share Exchange between Baltimore Gas and Electric Company and Constellation Energy Group, Inc. dated as of February 19, 1999. (Designated as Exhibit No. 2 to the Registration Statement on Form S-4 dated March 3, 1999, File No. 33-64799.)
*2(a)	Agreement and Plan of Reorganization and Corporate Separation (Nuclear). (Designated as Exhibit No. 2(a) to the Current Report on Form 8-K dated July 7, 2000, File Nos. 1-12869 and 1-1910.)
*2(b)	Agreement and Plan of Reorganization and Corporate Separation (Fossil). (Designated as Exhibit No. 2(b) to the Current Report on Form 8-K dated July 7, 2000, File Nos. 1-12869 and 1-1910.)
*2(c)	Agreement and Plan of Merger, dated December 18, 2005, by and among FPL Group, Inc., Constellation Energy Group, Inc. and CF Merger Corporation. (Designated as Exhibit No. 2.1 to the Current Report on Form 8-K dated December 19, 2005, File Nos. 1-12869 and 1-1910.)
*3(a)	Articles of Amendment and Restatement of the Charter of Constellation Energy Group, Inc. as of April 30, 1999. (Designated as Exhibit No. 99.2 to the Current Report on Form 8-K dated April 30, 1999, File No. 1-1910.)
*3(b)	Articles Supplementary to the Charter of Constellation Energy Group, Inc., as of July 19, 1999. (Designated as Exhibit No. 3(a) to the Quarterly Report on Form 10-Q for the quarter ended June 30, 1999, File Nos. 1-12869 and 1-1910.)
*3(c)	Certificate of Correction to the Charter of Constellation Energy Group, Inc. as of September 13, 1999. (Designated as Exhibit No. 3(c) to the Annual Report on Form 10-K for the year ended December 31, 1999, File Nos. 1-12869 and 1-1910.)

*3(d) Charter of BGE, restated as of August 16, 1996. (Designated as Exhibit No. 3 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 1996, File No. 1-1910.)

*3(e) Articles Supplementary to the Charter of Constellation Energy Group, Inc. as of November 20, 2001. (Designated as Exhibit No. 3(e) to the Annual Report on Form 10-K for the year ended December 31, 2001, File Nos. 1-12869 and 1-1910.)

*3(f) Bylaws of Constellation Energy Group, Inc., as amended to February 27, 2004. (Designated as Exhibit 3(a) to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2004, File Nos. 1-12869 and 1-1910.)

*3(g) Bylaws of BGE, as amended to October 16, 1998. (Designated as Exhibit No. 3 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 1998, File No. 1-1910.)

*4(a) Indenture between Constellation Energy Group, Inc. and the Bank of New York, Trustee dated as of March 24, 1999. (Designated as Exhibit No. 4(a) to the Registration Statement on Form S-3 dated March 29, 1999, File No. 333-75217.)

*4(b) First Supplemental Indenture between Constellation Energy Group, Inc. and the Bank of New York, Trustee dated as of January 24, 2003. (Designated as Exhibit No. 4(b) to the Registration Statement on Form S-3 dated January 24, 2003, File No. 333-102723.)

*4(c) Supplemental Indenture between BGE and Bankers Trust Company, as Trustee, dated as of June 20, 1995, supplementing, amending and restating Deed of Trust dated February 1, 1919. (Designated as Exhibit No. 4 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 1995, File No. 1-1910); and the following Supplemental Indentures between BGE and Bankers Trust Company, Trustee:

Dated	File No.	Designated In	Exhibit Number
*January 15, 1992	33-45259	(Form S-3 Registration)	4(a)(ii)
*February 15, 1993	1-1910	(Form 10-K Annual Report for 1992)	4(a)(i)
*March 1, 1993	1-1910	(Form 10-K Annual Report for 1992)	4(a)(ii)
*March 15, 1993	1-1910	(Form 10-K Annual Report for 1992)	4(a)(iii)
*April 15, 1993	1-1910	(Form 10-Q dated May 13, 1993)	4
*July 1, 1993	1-1910	(Form 10-Q dated August 13, 1993)	4(a)
*October 15, 1993	1-1910	(Form 10-Q dated November 12, 1993)	4
*June 15, 1996	1-1910	(Form 10-Q dated August 13, 1996)	4

*4(d) Indenture dated July 1, 1985, between BGE and The Bank of New York (Successor to Mercantile-Safe Deposit and Trust Company), Trustee. (Designated as Exhibit 4(a) to the Registration Statement on Form S-3, File No. 2-98443); as supplemented by Supplemental Indentures dated as of October 1, 1987 (Designated as Exhibit 4(a) to the Current Report on Form 8-K, dated November 13, 1987, File No. 1-1910) and as of January 26, 1993 (Designated as Exhibit 4(b) to the Current Report on Form 8-K, dated January 29, 1993, File No. 1-1910.)

*4(e) Form of Subordinated Indenture between the Company and The Bank of New York, as Trustee in connection with the issuance of the Junior Subordinated Debentures. (Designated as Exhibit 4(d) to the Registration Statement on Form S-3 dated August 5, 2003, File No. 333-107681.)

*4(f) Form of Supplemental Indenture between the Company and The Bank of New York, as Trustee in connection with the issuances of the Junior Subordinated Debentures. (Designated as Exhibit 4(e) to the Registration Statement on Form S-3 dated August 5, 2003, File No. 333-107681.)

*4(g) Form of Preferred Securities Guarantee (Designated as Exhibit 4(f) to the Registration Statement on Form S-3 dated August 5, 2003, File No. 333-107681.)

*4(h) Form of Junior Subordinated Debenture (Designated as Exhibit 4(h) to the Registration Statement on Form S-3 dated August 5, 2003, File No. 333-107681.)

*4(i) Form of Amended and Restated Declaration of Trust (including Form of Preferred Security) (Designated as Exhibit 4(c) to the Registration Statement on Form S-3 dated August 5, 2003, File No. 333-107681.)

*10(a)	Executive Annual Incentive Plan of Constellation Energy Group, Inc., as amended and restated. (Designated as Exhibit No. 10(a) to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2004, File Nos. 1-12869 and 1-1910.)
*10(b)	Constellation Energy Group, Inc. 1995 Long-Term Incentive Plan, as amended and restated. (Designated as Exhibit No. 10(b) to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2004, File Nos. 1-12869 and 1-1910.)
*10(c)	Constellation Energy Group, Inc. Nonqualified Deferred Compensation Plan, as amended and restated. (Designated as Exhibit No. 10(c) to the Annual Report on Form 10-K for the year ended December 31, 2002, File Nos. 1-12869 and 1-1910.)
*10(d)	Constellation Energy Group, Inc. Deferred Compensation Plan for Non-Employee Directors, as amended and restated. (Designated as Exhibit 10(d) to the Annual Report on Form 10-K for the year ended December 31, 2004, File Nos. 1-12869 and 1-1910.)
*10(e)	Compensation agreements between Constellation Energy Group, Inc. and E. Follin Smith (Attachment 1 Employment Agreement; Attachment 2 Severance Agreement (Attachment 2 superseded by amended and restated change in control severance agreement filed as Exhibit 10(y) to this Report.)(Designated as Exhibit 10(c) to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2004, File Nos. 1-12869 and 1-1910.)
10(f)	Amended and restated change in control severance agreement between Constellation Energy Group, Inc. and Thomas V. Brooks.
*10(g)	Grantor Trust Agreement Dated as of February 27, 2004 between Constellation Energy Group, Inc. and Citibank, N.A. (Designated as Exhibit No. 10(d) to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2004, File Nos. 1-12869 and 1-1910.)
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*10(j)	Full Requirements Service Agreement between Constellation Power Source, Inc. and Baltimore Gas and Electric Company. (Designated as Exhibit No. 10(a) to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2000, File Nos. 1-12869 and 1-1910.) (Portions of this exhibit have been omitted pursuant to a request for confidential treatment.)
*10(k)	Full Requirements Service Agreement between Constellation Power Source, Inc. and Baltimore Gas and Electric Company. (Designated as Exhibit No. 10(a) to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2001, File Nos. 1-12869 and 1-1910.) (Portions of this exhibit have been omitted pursuant to a request for confidential treatment.)
*10(l)	Full Requirements Service Agreement between Baltimore Gas and Electric Company and Allegheny Energy Supply Company, L.L.C. (Designated as Exhibit No. 10(b) to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2001, File Nos. 1-12869 and 1-1910.) (Portions of this exhibit have been omitted pursuant to a request for confidential treatment.)
*10(m)	Consent to Assignment and Assumption Agreement by and among Allegheny Energy Supply, L.L.C. and Baltimore Gas and Electric Company and Constellation Power Source, Inc. (Designated as Exhibit 10(l) to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2003, File Nos. 1-12869 and 1-1910.) (Portions of this exhibit have been omitted pursuant to a request for confidential treatment.)
*10(n)	Constellation Energy Group, Inc. Benefits Restoration Plan, as amended and restated. (Designated as Exhibit No. 10(m) to the Annual Report on Form 10-K for the year ended December 31, 2001, File Nos. 1-12869 and 1-1910.)
*10(o)	Constellation Energy Group, Inc. Supplemental Pension Plan, as amended and restated. (Designated as Exhibit No. 10(d) to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2004, File Nos. 1-12869 and 1-1910.)

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10(v)	Constellation Energy Group, Inc. 2002 Senior Management Long-Term Incentive Plan, as amended and restated.
10(w)	Constellation Energy Group, Inc. Management Long-Term Incentive Plan, as amended and restated.
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21	Subsidiaries of the Registrant.
23	Consent of PricewaterhouseCoopers LLP, Independent Registered Public Accounting Firm.
31(a)	Certification of Chairman of the Board, Chief Executive Officer and President of Constellation Energy Group, Inc. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
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*

Incorporated by Reference.

CONSTELLATION ENERGY GROUP, INC. AND SUBSIDIARIES

AND

BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARIES

SCHEDULE II VALUATION AND QUALIFYING ACCOUNTS

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at beginning of period	Charged to costs and expenses	Charged to Other Accounts Describe	(Deductions) Describe	Balance at end of period
			(In millions)		
Reserves deducted in the Balance Sheet from the assets to which they apply:					
Constellation Energy					
Accumulated Provision for Uncollectibles					
2005	$ 43.1	$ 30.9	$	$ (26.6)(A)	$ 47.4
2004	51.7	22.2		(30.8)(A)	43.1
2003	41.9	22.0		(12.2)(A)	51.7
Valuation Allowance					
Net unrealized loss on available for sale securities					
2005	0.1		0.5 (B)		0.6
2004			0.1 (B)		0.1
2003					
Net unrealized (gain) loss on nuclear decommissioning trust funds					
2005	(73.3)		(37.0)(B)		(110.3)
2004	(13.7)		(59.6)(B)		(73.3)
2003	47.4		(61.1)(B)		(13.7)
BGE					
Accumulated Provision for Uncollectibles					
2005	13.0	14.1		(14.1)(A)	13.0
2004	10.7	16.3		(14.0)(A)	13.0
2003	11.5	9.0		(9.8)(A)	10.7

(A) Represents principally net amounts charged off as uncollectible.

(B) Represents amounts recorded in or reclassified from accumulated other comprehensive income.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, Constellation Energy Group, Inc., the Registrant, has duly caused this Report to be signed on its behalf by the undersigned, thereunto duly authorized.

CONSTELLATION ENERGY GROUP, INC.
(REGISTRANT)

Date: March 2, 2006

By /s/ MAYO A. SHATTUCK III

Mayo A. Shattuck III
Chairman of the Board, Chief Executive Officer and President

Pursuant to the requirements of the Securities Exchange Act of 1934, this Report has been signed below by the following persons on behalf of Constellation Energy Group, Inc., the Registrant, and in the capacities and on the dates indicated.

Signature	Title	Date
Principal executive officer and director:		
By /s/ M. A. Shattuck III **M. A. Shattuck III**	Chairman of the Board, Chief Executive Officer, President and Director	March 2, 2006
Principal financial and accounting officer:		
By /s/ E. F. Smith **E. F. Smith**	Executive Vice President, Chief Financial Officer, and Chief Administrative Officer	March 2, 2006
Directors:		
/s/ Y. C. de Balmann **Y. C. de Balmann**	Director	March 2, 2006
/s/ D. L. Becker **D. L. Becker**	Director	March 2, 2006
/s/ J. T. Brady **J. T. Brady**	Director	March 2, 2006
/s/ F. P. Bramble, Sr.	Director	March 2, 2006

Signature	Title	Date
F. P. Bramble, Sr.		
/s/ E. A. Crooke	Director	March 2, 2006
E. A. Crooke		
/s/ J. R. Curtiss	Director	March 2, 2006
J. R. Curtiss		

/s/ F. A. Hrabowski, III	Director	March 2, 2006
F. A. Hrabowski, III		
/s/ N. Lampton	Director	March 2, 2006
N. Lampton		
/s/ R. J. Lawless	Director	March 2, 2006
R. J. Lawless		
/s/ L. M. Martin	Director	March 2, 2006
L. M. Martin		
/s/ M. D. Sullivan	Director	March 2, 2006
M. D. Sullivan		

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, Baltimore Gas and Electric Company, the Registrant, has duly caused this Report to be signed on its behalf by the undersigned, thereunto duly authorized.

BALTIMORE GAS AND ELECTRIC COMPANY
(REGISTRANT)

Date: March 2, 2006

By /s/ KENNETH W. DEFONTES, JR.

Kenneth W. DeFontes, Jr.
President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this Report has been signed below by the following persons on behalf of Baltimore Gas and Electric Company, the Registrant, and in the capacities and on the dates indicated.

Signature	Title	Date
Principal executive officer and director:		
By /s/ K. W. DeFontes, Jr. **K. W. DeFontes, Jr.**	President, Chief Executive Officer, and Director	March 2, 2006
Principal financial and accounting officer and director:		
By /s/ E. F. Smith **E. F. Smith**	Senior Vice President, Chief Financial Officer, and Director	March 2, 2006
Directors:		
/s/ M. A. Shattuck III **M. A. Shattuck III**	Director	March 2, 2006

EXHIBIT INDEX

Exhibit Number	
*2	Agreement and Plan of Share Exchange between Baltimore Gas and Electric Company and Constellation Energy Group, Inc. dated as of February 19, 1999. (Designated as Exhibit No. 2 to the Registration Statement on Form S-4 dated March 3, 1999, File No. 33-64799.)
*2(a)	Agreement and Plan of Reorganization and Corporate Separation (Nuclear). (Designated as Exhibit No. 2(a) to the Current Report on Form 8-K dated July 7, 2000, File Nos. 1-12869 and 1-1910.)
*2(b)	Agreement and Plan of Reorganization and Corporate Separation (Fossil). (Designated as Exhibit No. 2(b) to the Current Report on Form 8-K dated July 7, 2000, File Nos. 1-12869 and 1-1910.)
*2(c)	Agreement and Plan of Merger, dated December 18, 2005, by and among FPL Group, Inc., Constellation Energy Group, Inc. and CF Merger Corporation. (Designated as Exhibit No. 2.1 to the Current Report on Form 8-K dated December 19, 2005, File Nos. 1-12869 and 1-1910.)
*3(a)	Articles of Amendment and Restatement of the Charter of Constellation Energy Group, Inc. as of April 30, 1999. (Designated as Exhibit No. 99.2 to the Current Report on Form 8-K dated April 30, 1999, File No. 1-1910.)
*3(b)	Articles Supplementary to the Charter of Constellation Energy Group, Inc., as of July 19, 1999. (Designated as Exhibit No. 3(a) to the Quarterly Report on Form 10-Q for the quarter ended June 30, 1999, File Nos. 1-12869 and 1-1910.)
*3(c)	Certificate of Correction to the Charter of Constellation Energy Group, Inc. as of September 13, 1999. (Designated as Exhibit No. 3(c) to the Annual Report on Form 10-K for the year ended December 31, 1999, File Nos. 1-12869 and 1-1910.)
*3(d)	Charter of BGE, restated as of August 16, 1996. (Designated as Exhibit No. 3 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 1996, File No. 1-1910.)
*3(e)	Articles Supplementary to the Charter of Constellation Energy Group, Inc. as of November 20, 2001. (Designated as Exhibit No. 3(e) to the Annual Report on Form 10-K for the year ended December 31, 2001, File Nos. 1-12869 and 1-1910.)
*3(f)	Bylaws of Constellation Energy Group, Inc., as amended to February 27, 2004. (Designated as Exhibit 3(a) to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2004, File Nos. 1-12869 and 1-1910.)
*3(g)	Bylaws of BGE, as amended to October 16, 1998. (Designated as Exhibit No. 3 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 1998, File No. 1-1910.)
*4(a)	Indenture between Constellation Energy Group, Inc. and the Bank of New York, Trustee dated as of March 24, 1999. (Designated as Exhibit No. 4(a) to the Registration Statement on Form S-3 dated March 29, 1999, File No. 333-75217.)
*4(b)	First Supplemental Indenture between Constellation Energy Group, Inc. and the Bank of New York, Trustee dated as of January 24, 2003. (Designated as Exhibit No. 4(b) to the Registration Statement on Form S-3 dated January 24, 2003, File No. 333-102723.)
*4(c)	Supplemental Indenture between BGE and Bankers Trust Company, as Trustee, dated as of June 20, 1995, supplementing, amending and restating Deed of Trust dated February 1, 1919. (Designated as Exhibit No. 4 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 1995, File No. 1-1910); and the following Supplemental Indentures between BGE and Bankers Trust Company, Trustee:

Dated	File No.	Designated In	Exhibit Number
*January 15, 1992	33-45259	(Form S-3 Registration)	4(a)(ii)
*February 15, 1993	1-1910	(Form 10-K Annual Report for 1992)	4(a)(i)
*March 1, 1993	1-1910	(Form 10-K Annual Report for 1992)	4(a)(ii)
*March 15, 1993	1-1910	(Form 10-K Annual Report for 1992)	4(a)(iii)
*April 15, 1993	1-1910	(Form 10-Q dated May 13, 1993)	4
*July 1, 1993	1-1910	(Form 10-Q dated August 13, 1993)	4(a)
*October 15, 1993	1-1910	(Form 10-Q dated November 12, 1993)	4
*June 15, 1996	1-1910	(Form 10-Q dated August 13, 1996)	4

*4(d)	Indenture dated July 1, 1985, between BGE and The Bank of New York (Successor to Mercantile-Safe Deposit and Trust Company), Trustee. (Designated as Exhibit 4(a) to the Registration Statement on Form S-3, File No. 2-98443); as supplemented by Supplemental Indentures dated as of October 1, 1987 (Designated as Exhibit 4(a) to the Current Report on Form 8-K, dated November 13, 1987, File No. 1-1910) and as of January 26, 1993 (Designated as Exhibit 4(b) to the Current Report on Form 8-K, dated January 29, 1993, File No. 1-1910.)
*4(e)	Form of Subordinated Indenture between the Company and The Bank of New York, as Trustee in connection with the issuance of the Junior Subordinated Debentures. (Designated as Exhibit 4(d) to the Registration Statement on Form S-3 dated August 5, 2003, File No. 333-107681.)
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