CONSTELLATION ENERGY GROUP INC
Form 10-K
March 07, 2003

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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, 2002**

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)

410-234-5000

(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.
7.16% Trust Originated Preferred Securities ($25 liquidation amount per preferred security) issued by BGE Capital Trust I, 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 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 an accelerated filer Yes ý No o.

Indicate by check mark whether Baltimore Gas and Electric Company is an accelerated filer Yes o No ý.

Aggregate market value of Constellation Energy Group, Inc. Common Stock, without par value, held by non-affiliates as of June 28, 2002 was approximately $4,791,476,554 and February 28, 2003 was approximately $4,293,890,795 based upon New York Stock Exchange composite transaction closing price.

CONSTELLATION ENERGY GROUP, INC. COMMON STOCK, WITHOUT PAR VALUE 164,764,752 SHARES OUTSTANDING ON FEBRUARY 28, 2003.

DOCUMENTS INCORPORATED BY REFERENCE

Part of Form 10-K	Document Incorporated by Reference
III	Certain sections of the Proxy Statement for Constellation Energy Group, Inc. for the Annual Meeting of Shareholders to be held on April 25, 2003.

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," "expects," "intends," "plans," and other similar words. These statements 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 including coal, natural gas, oil, electricity and emission allowances,
- the timing and extent of deregulation of, and competition in, the energy markets in North America, and the rules and regulations adopted on a transitional basis in those markets,
- the conditions of the capital markets, interest rates, availability of credit, liquidity, and general economic conditions, as well as Constellation Energy and BGE's ability to maintain their current credit ratings,
- the effectiveness of Constellation Energy and BGE's risk management policies and procedures and the ability of their counterparties to satisfy their financial and performance commitments,
- the liquidity and competitiveness of wholesale markets for energy commodities,
- operational factors affecting the start-up or ongoing 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 gas transportation or electric transmission services, workforce issues, terrorism, liabilities associated with catastrophic events, and other events beyond our control,
- the inability of BGE to recover all its costs associated with providing electric retail customers service during the electric rate freeze period,
- the effect of weather and general economic and business conditions on energy supply, demand, and prices,
- regulatory or legislative developments that affect deregulation, transmission or distribution rates and revenues, demand for energy, or increase costs, including costs related to nuclear power plants, safety, or environmental compliance,

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,

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

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, and

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

Given these uncertainties, you should not place undue reliance on these forward looking statements. Please see the other sections of this report and our other periodic reports filed with the 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

Overview

Constellation Energy Group, Inc. (Constellation Energy) is a North American energy company that conducts its business through various subsidiaries including a merchant energy business and Baltimore Gas and Electric Company (BGE).

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 website address for BGE is bge.com. Both website addresses are inactive textual references and the contents of these websites are not part of this Form 10-K.

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 through a share exchange. References in this report to "we" and "our" are to Constellation Energy and its subsidiaries, collectively. References in this report to the "utility business" are to BGE.

Our merchant energy business is a competitive provider of energy solutions for large customers in North America. 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 of, and providing other risk management activities for various customers, such as utilities, municipalities, cooperatives, retail aggregators, and large commercial and industrial customers.

Our merchant energy business includes:

fossil, nuclear, and hydroelectric generating facilities and interests in qualifying facilities and power projects in the United States, origination of structured transactions (such as load-serving, tolling contracts, and power purchase agreements), and risk management services (hedging of output from generating facilities and fuel costs),

electric and gas retail energy services to large commercial and industrial customers, and

generation and consulting services.

BGE is a regulated electric and gas public transmission and 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 single-site heating, cooling, and cogeneration facilities for commercial and industrial customers,

provide home improvements, service heating, air conditioning, plumbing, electrical, and indoor air quality systems, and provide electric and natural gas retail marketing, and

own and operate a district cooling system for commercial customers in the City of Baltimore, Maryland.

In addition, we own several investments that we do not consider to be core operations. These include financial investments, real estate projects, and interests in a Latin American distribution project and in a fund that holds interests in two South American energy projects. We decided to sell certain non-core assets and accelerated the exit strategies of other projects. We sold certain non-core assets in 2002 and closed our retail merchandise stores in December 2002.

For a discussion of recent events that have impacted Constellation Energy, please refer to *Item 7. Management's Discussion and Analysis Significant Events* section. For a discussion of Constellation Energy's strategy, please refer to *Item 7. Management's Discussion and Analysis Strategy* section. For a discussion of the seasonality of our business, please refer to *Item 7. Management's Discussion and Analysis Business Environment* section.

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 special items, in *Note 3 to Consolidated Financial Statements*. Effective July 1, 2000, the financial results of the electric generation portion of our business are included in the merchant energy business segment. Prior to that date, the financial results are included in the regulated electric segment.

	Unaffiliated Revenues			
	Merchant Energy	**Regulated Electric**	**Regulated Gas**	**Other Nonregulated**
2002	35%	42%	12%	11%
2001	16	53	17	14
2000	11	57	16	16

	Net income(1)			
	Merchant Energy	**Regulated Electric**	**Regulated Gas**	**Other Nonregulated**
2002	67%	29%	8%	(4)%
2001	75	22	10	(7)
2000	68	34	9	(11)

Total Assets

	Total Assets			
	Merchant Energy	Regulated Electric	Regulated Gas	Other Nonregulated & Corp. Items
2002	63%	25%	8%	4%
2001	57	27	8	8
2000	56	26	9	9

(1) Excludes special items included in operations and a cumulative effect of change in accounting principle 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 over time. Constellation Power Source, our origination and risk management operation, dispatches the energy from our generating facilities, manages the risks associated with selling the output and obtaining the fuel, and structures transactions to meet customers' energy and risk management requirements. Generation capacity supports our origination and risk management operation by providing a source of reliable power supply that provides a physical hedge for some of our load-serving activities.

Our merchant energy business:

- provides service to distribution utilities, municipalities, and large commercial and industrial customers with approximately 18,700 megawatts (MW) of peak load in the aggregate,
- owns approximately 11,300 MW of generation capacity, and
- has under construction an 830 MW natural gas-fired combined cycle generating facility in California.

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

- PJM Platform our fossil, nuclear, and hydroelectric generating facilities and load-serving activities in the PJM Interconnection (PJM) region for which the output is primarily used to serve BGE.
- Plants with Power Purchase Agreements our generating facilities with long-term power purchase agreements, including our Nine Mile Point Nuclear Station (Nine Mile Point) nuclear generating facility and our new Oleander and University Park generating facilities.
- Competitive Supply our wholesale business that provides load-serving activities to distribution utilities (primarily in Texas and New England), other wholesale origination and risk management services, and electric and gas retail energy services to large commercial and industrial customers.
- Other our other gas-fired generating facilities, investments in qualifying facilities and domestic power projects, and our generation and consulting services.

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

PJM Platform

We own 6,485 MW of fossil, nuclear and hydroelectric generation capacity in the PJM region. The output of these plants is managed by our origination and risk management operation and is hedged through a combination of power sales to wholesale and retail market participants.

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 project that commenced operations in mid-2001. The assets transferred from BGE are subject to the lien of BGE's mortgage.

These facilities include the Calvert Cliffs Nuclear Power Plant (two units), which is our largest generating station. In March 2000, Calvert Cliffs became the first nuclear power plant in the United States to achieve license renewal. The Nuclear Regulatory Commission (NRC) approved a twenty-year license renewal for both units of Calvert Cliffs, extending the license for Unit 1 to 2034 and for Unit 2 to 2036.

Our merchant energy business provides standard offer electric service to BGE as discussed in the *Baltimore Gas and Electric Company* section. Our merchant energy business meets the load-serving requirements of this contract using the output from the PJM facilities and from purchases in the wholesale market. For 2002, the peak load supplied to BGE was approximately 5,425 MW.

Plants with Power Purchase Agreements

We own 2,530 MW of nuclear and natural gas generation capacity, and have under construction an 830 MW natural gas-fired facility that will commence operation in 2003, with power purchase agreements for their output. These facilities include Nine Mile Point, which is our second largest generating station. We purchased 100% of Unit 1 (609 MW) and 82% of Unit 2 (941 MW) in November 2001. The remaining interest in Nine Mile Point Unit 2 is owned by a subsidiary of 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 percent of our share of the Nine Mile Point plant's output back to the sellers at an average price of nearly $35 per megawatt-hour (MWH) under agreements that terminate between 2009 and 2010. The agreements for the output of both units 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 origination and risk management operation and sold into the wholesale market.

After termination of the power purchase agreements, a revenue sharing agreement will begin and continue through 2021. Under this agreement, which applies only to Unit 2, a strike price is compared to the market price for electricity. If the market price exceeds the strike price, then 80% of this excess amount is shared with the sellers. The revenue sharing agreement is unit contingent and is based on the operation of the unit.

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

The license on Nine Mile Point's Unit 1 expires in 2009 and in 2026 on Unit 2. We have commenced a license extension initiative for both units with the objective of obtaining up to 20 years of additional operations. We expect to submit the license extension application to the NRC in the fall of 2003.

Our other facilities with power purchase agreements consist of:

- the Oleander project, which commenced operations in mid-2002, and
- the University Park project, which commenced operations in mid-2001.

We have sold portions of the output of these facilities ranging from 50% to 100% under tolling contracts for terms ending in 2005 through 2009. Under these tolling contracts, our respective counterparties 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.

We are currently leasing and supervising the construction of the High Desert Power Project, an 830 MW natural-gas fired combined cycle generating facility in Victorville, California. The project is scheduled for completion in mid-2003.

We signed a long-term power sales agreement with the State of California. The contract is a "tolling" structure, under which the California Department of Water Resources (CDWR) will pay a fixed amount of $12.1 million per month and provides the CDWR the right, but not the obligation, to purchase power from the High Desert Power Project at a price linked to the variable cost of production. During the term of the contract, which runs for seven years and nine months from the commercial operation date of the plant, the High Desert Power Project will provide energy exclusively to the CDWR. The capacity payment is proportionately reduced if the plant's availability is less than 95%. We discuss the High Desert project in more detail in *Item 7. Management's Discussion and Analysis Significant Events* section.

Competitive Supply

We are a leading supplier of energy through load-serving activities in North America to wholesale customers and large commercial and industrial customers and assist them in managing their energy needs. Our competitive supply activities include the 800 MW Rio Nogales natural gas-fired generating facility that commenced operation in mid-2002 and is used to manage our Texas portfolio.

Origination of Structured Transactions

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 that serve the full energy and capacity requirements and other operational and administrative processes for large commercial and industrial customers.

These activities typically occur in regional markets in which end user customers' electricity rates have been deregulated and thereby separated from the cost of generation supply. These markets include: New England, the Mid-Atlantic, Texas, the Midwest, the West, and certain areas of Canada. Contracts with these customers generally extend from one to ten years, but some can be longer. We currently have approximately 18,700 MW of load under contract for 2003.

In 2002, we acquired NewEnergy and Alliance as discussed in *Item 7. Management's Discussion and Analysis Significant Events* section. These acquisitions expand our business in the competitive supply market by providing electricity, natural gas, transportation, and other energy related services to large commercial and industrial customers throughout the United States.

To meet our customers' load-serving requirements, our merchant energy business obtains energy from various sources, including:

- our generation assets (including our new Rio Nogales gas-fired facility),
- tolling contracts, 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 generation companies that generally extend from several months to several years but can be longer,
- bilateral power purchase agreements with third parties, or
- regional power pools.

Risk Management Activities

Our origination 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, to obtain market intelligence, and to take advantage of arbitrage opportunities that exist across different markets. 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 origination and risk management operation to manage and hedge its fixed-price purchase and sale commitments; provide fixed-price commitments to customers and suppliers; reduce exposure to the volatility of cash market prices; and hedge fuel requirements at our generation facilities.

Other

We own 1,491 MW of generating facilities and qualifying facilities and domestic power projects, which include several natural gas-fired facilities that commenced operation since 2001. The output of these facilities is managed by our origination and risk management operation and sold into the wholesale market.

In addition, we hold up to a 50% ownership interest in 28 operating energy projects that consist of electric generation (primarily relying on alternative fuel sources), fuel processing, or fuel handling facilities and are either qualifying facilities under the Public Utility Regulatory Policies Act of 1978 or otherwise exempt from, or not subject to, the Public Utility Holding Company Act of 1935. Each electric generating plant sells its output to a local utility under long-term contracts.

Our merchant energy business has invested in partnerships that own 13 operating power projects of which our ownership percentage represents 137 megawatts of electricity that are sold to Pacific Gas & Electric (PGE) and to Southern California Edison (SCE) in California under power purchase agreements. The projects entered into agreements with PGE through July 2006 and SCE through April 2007 that provide for fixed-price payments averaging $53.70 per megawatt-hour plus the stated capacity payments in the original agreements.

We also provide the following services:

- operation and maintenance services, including testing and start-up, to owners of electric generating facilities, and
- nuclear consulting services to the nuclear utility industry, along with plant life cycle support services, including aging management, spent fuel management, and project management and engineering.

Fuel Sources

Our power plants use diverse fuel sources. Our fuel mix based on capacity owned at December 31, 2002 and our generation based on actual output by fuel type in 2002 were as follows:

Fuel	Capacity Owned	Generation
Nuclear	28.6%	53.4%
Coal	24.2	35.7
Natural Gas	25.6	3.3
Oil	6.7	1.3
Renewable and Alternative(1)	4.3	4.3
Dual(2)	10.6	2.0

(1)

Includes solar, geothermal, hydro, biomass, and waste-to-energy.

(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* section.

Nuclear

The output at Calvert Cliffs over the past five years has been:

	Generation MWH	Capacity Factor
2002	12,087,408	82%
2001	13,648,932	92
2000	13,826,046	93
1999	13,309,306	91
1998	13,326,633	91

The output at Nine Mile Point over the past five years has been:

	Generation MWH*	Capacity Factor
2002	11,727,567	87%
2001	11,613,519	86
2000	11,243,095	83
1999	10,766,425	79
1998	10,837,848	80

*represents our proportionate ownership interest

The supply of fuel for nuclear generating stations includes the:

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

Uranium Concentrates:	We have under contract sufficient quantities of uranium to meet 100% of both Calvert Cliffs' and Nine Mile Point's requirements through 2004, 50% for both plants in 2005, 60% for both plants in 2006 and 25% for both plants in 2007.
Conversion:	We have contractual commitments providing for the conversion of uranium concentrate into uranium hexafluoride that will meet 100% of Calvert Cliffs' and Nine Mile Point's requirements through 2004, 50% for both plants in 2005, 67% for both plants in 2006 and 50% for both plants in 2007.
Enrichment:	We have contractual commitments that provide 100% of Calvert Cliffs' and Nine Mile Point's uranium enrichment requirements through 2006 and 25% of these requirements for both plants in 2007 and 2008.
Fuel Assembly Fabrication:	We have contracted for the fabrication of fuel assemblies for reloads required through 2013 at Calvert Cliffs and through 2005 for Nine Mile Point Unit 2 and through 2009 for Nine Mile Point Unit 1.

The nuclear fuel markets are competitive and we do not anticipate any problem 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. The Nuclear Waste Policy Act of 1982 required the federal government, through the Department of Energy (DOE) by January 31, 1998, to begin to dispose of spent nuclear fuel. The federal government has stated that it will not meet that obligation until 2010 at the earliest.

The 1982 Act assesses a tenth of one cent (one mill) per kilowatt-hour fee on nuclear electricity generated and sold to pay for the costs of disposing of spent fuel. We estimate this fee to be approximately $13 million for Calvert Cliffs and $12 million for our portion of Nine Mile Point each year based on expected operating levels. We will pay our portion of these fees into the DOE's Nuclear Waste Fund.

On February 14, 2002, the Secretary of Energy submitted to the President a recommendation for approval of the Yucca Mountain site for the development of a nuclear waste repository for the disposal of spent nuclear fuel and high level nuclear waste from the nation's defense activities. In July 2002, the President signed a resolution approving the Yucca Mountain site after receiving the approval of the U.S. Senate and House of Representatives. This action allows the Department of Energy to apply to the NRC to license the project. The Department of Energy currently expects that this facility will open in 2010. However, the opening of Yucca Mountain could be delayed due to multiple lawsuits initiated by the State of Nevada and other interested parties, the NRC licensing hearings, and other issues related to the site.

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 does not have independent spent fuel storage capacity. Rather, Nine Mile Point's Unit 1 has sufficient storage capacity within the plant until the end of its current operating license in 2009. If license renewal is obtained, independent spent fuel storage capability will need to be developed. 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.

Cost for Decommissioning Uranium Enrichment Facilities

The Energy Policy Act of 1992 contains provisions requiring 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. The sellers of the Nine Mile Point plant and a subsidiary of the Long Island Power Authority are responsible for the costs relating to the Nine Mile Point plant.

Cost for Decommissioning

We are obligated to decommission our nuclear plants at the time these plants cease operation. Both Calvert Cliffs and Nine Mile Point are required by the NRC to prepare financially for this decommissioning. 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, 2002, the trust fund was $239.7 million.

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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. 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 amount 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 at the time of sale. In return, Nine Mile Point assumed all liability for the costs to decommission Unit 1 and 82% of the cost 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, 2002, the Nine Mile Point trust fund was $405.7 million.

Coal

We purchase the majority of our coal 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	Special Coal Restrictions

	Requirement (tons)	
Brandon Shores Units 1 and 2 (combined)	3,500,000	Sulfur content less than 0.8%
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. The coal we use is produced from mines located in central and northern Appalachia.

All of the Conemaugh and Keystone plants' annual coal requirements are purchased from regional suppliers on the open market. The sulfur restrictions on coal are approximately 2.5% for the Keystone plant and approximately 4.5% 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. Each plant is restricted to coal with sulfur content less than 4%.

All of our 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 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 1,500,000 to 2,000,000 barrels of low-sulfur oil per year. Deliveries of residual fuel oil are made from the suppliers' Baltimore Harbor marine terminal for distribution to the various generating plant locations. Also, based on normal burn practices, we also require approximately 5,000,000 to 6,000,000 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 either curtailed their activities or have withdrawn completely from the business. In addition, other companies are entering the market (i.e., financial investors). 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 the 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, many of whom have extensive and diversified operating expertise including various utilities, industrial companies and independent power producers (including affiliates of utilities), and some of which have financial resources that are greater than ours.

During the transition of the energy industry to competitive markets, it is difficult for us to assess our position versus the position of existing power providers and new entrants because each company may employ widely differing strategies in their fuel supply and power sales contracts with regard to pricing, terms and conditions. Further difficulties in making competitive assessments of our company arise from states considering different types of regulatory initiatives concerning competition in the power industry. 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. In addition, some states that were considering deregulation have slowed their plans or postponed consideration of deregulation.

We believe there is adequate growth potential in the current deregulated market. However, in response to regional market differences and to promote competitive markets, the Federal Energy Regulatory Commission (FERC) proposed initiatives promoting the formation of Regional Transmission Organizations and a standard market design. If approved, these market changes could provide additional opportunities for our merchant energy business. Additionally, while competition has been adversely impacted by recent market events including the weakened financial condition of certain energy companies, we expect our business to become more competitive due to technological advances in power generation, e-commerce enabling new ways of conducting business, the entrance of new full service providers, and increased efficiency of energy markets.

However, we believe that our experience and expertise in assessing and managing risk will help us to remain competitive during volatile or otherwise adverse market circumstances.

Merchant Energy Operating Statistics

		2002		2001		2000		1999		1998
Revenues *(In millions)*										
PJM Platform	**$**	**1,391.4**	$	1,379.2	$	731.7	$		$	
Plants with Power Purchase Agreements		**456.4**		70.8						
Competitive Supply Accrual Revenues		**587.6**								
Mark-to-Market Revenues		**238.1**		175.8		151.5		147.7		47.5
Other		**92.2**		139.7		142.5		129.6		136.1
Total Revenue	**$**	**2,765.7**	$	1,765.5	$	1,025.7	$	277.3	$	183.6
Generation *(In millions)* MWH		**44.7**		37.4		18.8		1.3		1.3

Operating statistics do not reflect the elimination of intercompany transactions.

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Baltimore Gas and Electric Company

BGE is an electric and gas public transmission and 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 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. In 2002, BGE's largest electric customer provided approximately three percent of BGE's total electric revenues. In 2002, BGE's largest gas customer provided approximately one percent of BGE's total gas revenues.

Electric Business

Electric Regulatory Matters and Competition

Deregulation

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 effective July 1, 2000:

All customers can choose their electric energy supplier. BGE provides a fixed price standard offer service over various time periods for different classes of customers that do not select an alternative supplier until June 30, 2006.

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

BGE provides a market rate standard offer service for those commercial and industrial customers who are no longer eligible for fixed price standard offer service until June 30, 2006.

BGE reduced residential base rates by approximately 6.5% on average, or about $54 million a year, from rates prior to July 1, 2000. These rates will not change before July 2006. While total residential base rates remain unchanged over this transition period (July 1, 2000 through June 30, 2006), the increase in the standard offer service rate is offset by a corresponding decrease in the competitive transition charge (CTC) that BGE receives from its customers.

Commercial and industrial customers have several service options that will fix electric energy rates through June 30, 2004 and transition charges through June 30, 2006.

BGE transferred, at book value, its nuclear generating assets, its nuclear decommissioning trust fund, and related liabilities to Calvert Cliffs Nuclear Power Plant, Inc. In addition, BGE transferred, at book value, its fossil generating assets and related liabilities and its partial ownership interest in two coal plants and a hydroelectric plant located in Pennsylvania to Constellation Power Source Generation.

BGE assigned approximately $47 million to Calvert Cliffs Nuclear Power Plant, Inc. and $231 million to Constellation Power Source Generation of tax-exempt debt related to the transferred assets. At December 31, 2002, BGE remains contingently liable for the $269.8 million outstanding balance of this debt.

Standard Offer Service

Our origination and risk management operation provides BGE with 100% of the energy and capacity required to meet its standard offer service obligations through June 30, 2003. Beginning July 1, 2003, this operation will provide 90% and Allegheny Energy Supply Company, LLC will provide the remaining 10% of the energy and capacity required for BGE to meet its standard offer service obligations until June 30, 2006.

Beginning July 1, 2002, the fixed price standard offer service rate ended for large commercial and industrial customers. As a result, customers representing approximately 96% (approximately 1,200 megawatts) of load from this class purchase their electricity from an alternate supplier, including subsidiaries of Constellation Energy. The remaining large commercial and industrial customers that continue to receive their electric supply from BGE are charged market rate standard offer service.

Beginning July 1, 2004, all other commercial and industrial customers that continue to receive their electric supply from BGE will be charged a market rate standard offer service. Currently, this class of customers represents approximately 2,200 megawatts of load. Beginning July 1, 2006, BGE's current obligation to provide fixed price standard offer service to residential customers ends.

BGE's (and other Maryland utilities') role in providing electricity supply to customers is currently the subject of a proceeding at the Maryland PSC. Specifically, BGE entered into a proposed settlement agreement with parties representing customers, industry, utilities, suppliers, the Maryland Energy Administration, the Maryland PSC's Staff, and the Office of People's Counsel that extends BGE's obligation to supply standard offer service.

Under the proposed settlement agreement, BGE would be obligated to provide market-based standard offer service to residential customers until June 30, 2010, and for commercial and industrial customers for a one, two or four year period beyond June 30, 2004, depending on customer size. The rates charged during this time would be fixed during the term of the supply contract and would include an administrative fee. The proposed settlement agreement currently is before the Maryland PSC for approval.

We discuss the market risk of our regulated electric business in more detail in *Item 7. Management's Discussion and Analysis Market Risk* section.

Competition

The electric transmission and distribution services are facing competition from alternative energy sources that include on-site generation and cogeneration projects. In future years, emerging technologies, including fuel cells and solar panels, may also become a competitive factor.

Electric Load Management

BGE 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:

- customer-owned generation and curtailable service for large commercial and industrial customers,
- air conditioning control for residential and commercial customers, and
- residential water heater control.

BGE generally activates these programs on summer days when demand and/or wholesale prices are relatively high. The reduction in the summer 2002 peak load from active load management was approximately 260 MW.

Transmission and Distribution Facilities

BGE maintains approximately 250 substations and 1,300 circuit miles of transmission lines throughout central Maryland. BGE also maintains nearly 22,500 circuit miles of distribution lines. The transmission facilities are connected to those of neighboring utility systems as part of the PJM Interconnection. 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 FERC's initiatives in implementing a standard market design for wholesale electric markets in more detail in *Item 7. Management's Discussion and Analysis FERC Regulation* section.

Electric Operating Statistics

	2002	2001	2000(A)	1999(A)	1998(A)
Revenues *(In millions)*					
Residential	**$ 946.6**	$ 885.3	$ 922.6	$ 975.2	$ 948.6
Commercial	**809.5**	903.0	926.2	939.3	912.9
Industrial	**169.6**	218.1	203.6	204.3	211.5
System Sales	**1,925.7**	2,006.4	2,052.4	2,118.8	2,073.0
Interchange Sales			53.8	112.1	120.8

		2002		2001		2000(A)		1999(A)		1998(A)
Other (B)		**40.3**		33.6		29.0		29.1		27.0
Total	**$**	**1,966.0**	$	2,040.0	$	2,135.2	$	2,260.0	$	2,220.8
Sales *(In thousands)* MWH										
Residential		**12,652**		11,714		11,675		11,349		10,965
Commercial		**14,602**		14,147		14,042		13,565		13,219
Industrial		**4,475**		4,445		4,476		4,350		4,583
System Sales		**31,729**		30,306		30,193		29,264		28,767
Customers *(In thousands)*										
Residential		**1,052.3**		1,040.5		1,033.4		1,021.4		1,009.1
Commercial		**110.8**		110.9		108.9		107.7		106.5
Industrial		**4.9**		5.0		5.0		4.7		4.6
Total		**1,168.0**		1,156.4		1,147.3		1,133.8		1,120.2

(A) Operating statistics reflect the generation function as part of regulated electric operations through June 30, 2000.

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

Operating statistics do not reflect the elimination of intercompany transactions.

Gas Business

Currently, no regulation exists for the wholesale price of natural gas as a commodity, and the regulation of interstate transmission at the federal level has been reduced. All BGE gas customers have the option to purchase gas from other suppliers. BGE continues to deliver gas to all customers within its service territory. This delivery service is regulated by the Maryland PSC.

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

Delivery service customers may choose to purchase gas from several different suppliers, including subsidiaries of Constellation Energy. The basis of competition for delivery service customers is primarily commodity price.

Approximately 50% of the gas on our distribution system is for customers using delivery service. We charge all our delivery service customers fees to recover the costs for the transportation service we provide. These fees are the same as the delivery charges to customers that purchase gas from us.

For customers that buy their gas from BGE, there is a market-based rates incentive mechanism. Under market-based rates, 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.

We purchase the natural gas we resell to customers directly from many producers and marketers. We have transportation and storage agreements that expire from 2004 to 2012.

Our current pipeline firm transportation entitlements to serve our firm loads are 284,053 dekatherms (DTH) per day during the winter period and 259,053 DTH per day during the summer period.

Our current maximum storage entitlements are 235,080 DTH per day. To supplement our gas supply at times of heavy winter demands and to be available in temporary emergencies affecting gas supply, we have:

- 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.

We have under contract sufficient volumes of propane for the operation of the propane air facility and are capable of liquefying sufficient volumes of natural gas during the summer months for operations of our liquefied natural gas facility during winter emergencies.

We historically have been able to arrange short-term contracts or exchange agreements with other gas companies in the event of short-term disruptions to gas supplies.

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 our service territory. Earnings from these activities are shared between shareholders and customers. We make these sales as part of a program to balance our supply of, and cost of, natural gas.

Gas Operating Statistics

	2002	2001	2000	1999	1998
Revenues *(In millions)*					
Residential					
Excluding Delivery Service	**$ 342.1**	$ 378.4	$ 328.4	$ 298.1	$ 279.2
Delivery Service	**16.5**	16.3	23.5	11.5	4.9
Commercial					
Excluding Delivery Service	**89.4**	115.5	97.9	79.3	75.6
Delivery Service	**29.2**	21.4	25.8	24.4	19.4
Industrial					
Excluding Delivery Service	**9.3**	12.8	10.9	8.2	8.0
Delivery Service	**13.9**	13.8	16.3	16.1	16.0
System Sales	**500.4**	558.2	502.8	437.6	403.1
Off-system Sales	**74.8**	113.6	101.0	42.9	40.9
Other	**6.1**	8.9	7.8	7.6	7.1
Total	**$ 581.3**	$ 680.7	$ 611.6	$ 488.1	$ 451.1

	2002	2001	2000	1999	1998
Sales *(In thousands)* DTH					
Residential					
Excluding Delivery Service	**35,364**	33,147	34,561	34,272	33,595
Delivery Service	**6,404**	7,201	9,209	4,468	1,890
Commercial					
Excluding Delivery Service	**11,583**	12,334	13,186	11,733	11,775
Delivery Service	**28,429**	25,037	22,921	20,288	16,633
Industrial					
Excluding Delivery Service	**1,207**	1,386	1,386	1,367	1,412
Delivery Service	**23,689**	23,872	32,382	33,118	34,798
System Sales	**106,676**	102,977	113,645	105,246	100,103
Off-system Sales	**18,551**	20,012	22,456	15,543	16,724
Total	**125,227**	122,989	136,101	120,789	116,827
Customers *(In thousands)*					
Residential	**567.3**	558.7	553.7	543.5	532.5
Commercial	**40.7**	40.2	40.1	39.9	39.6
Industrial	**1.3**	1.4	1.4	1.3	1.3
Total	**609.3**	600.3	595.2	584.7	573.4

Operating statistics do not reflect the elimination of intercompany transactions.

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Franchises

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

Other Nonregulated Businesses

Energy Products and Services

We offer energy products and services designed primarily to provide solutions to the energy needs of commercial and industrial customers. These energy products and services include:

- designing, constructing, and operating single-site 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 Electric and Gas Retail Marketing

We offer services to customers including:

- home improvements,
- the service of heating, air conditioning, plumbing, electrical, and indoor air quality systems, and
- electric and natural gas retail marketing.

District Cooling Services

We also provide cooling services using a central chilled water distribution system to commercial customers in the City of Baltimore.

Other

Our other nonregulated businesses include investments that we do not consider to be core operations. These include financial investments, real estate projects, and interests in a Latin American distribution project and in a fund that holds interests in two South American energy projects. In 2001, as part of our strategy to focus attention and capital resources on our core energy businesses, we accelerated our exit strategies for our remaining real estate projects and international investments.

Consolidated Capital Requirements

Our business requires a great deal of capital. Our total capital requirements for 2002 were $923 million. Of this amount, $706 million was used in our nonregulated businesses and $217 million was used in our utility operations. We estimate our total capital requirements to be $735 million in 2003.

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

Environmental Matters

We are subject to regulation by various federal, state, and local authorities with regard to:

- air quality,
- water quality, and
- disposal of hazardous substances.

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 siting and developing, 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, special, protected and cultural resources (such as wetlands, endangered species, and archeological/historical resources), chemical, and waste handling and noise impacts.

Our activities require complex and often lengthy processes to obtain approvals, permits, or licenses for new, existing, or modified facilities. Additionally, the use and handling of various chemicals or hazardous materials (including wastes) requires preparation of release prevention plans and emergency response procedures. We continuously monitor federal and state environmental initiatives in order to provide input as well as to maintain a proactive view of the future which is key to effective strategic planning. Additionally, as new laws or regulations are promulgated, we assess their applicability and implement the necessary modifications to our facilities or their operation, as required.

Our capital expenditures (excluding allowance for funds used during construction) were approximately $265 million during the five-year period 1998-2002 to comply with existing environmental standards and regulations, and we estimate that the future incremental capital expenditures necessary to comply with existing environmental standards and regulations will be approximately $20 million in 2003.

Clean Air Act

The Clean Air Act affects both existing generating facilities and new projects. The Clean Air Act and many state laws require significant reductions in SO_2 (sulfur dioxide) and NO_X (nitrogen oxide) emissions that result from burning fossil fuels. The Clean Air Act also contains other provisions that could materially affect some of our projects. Various provisions may require permits, inspections, or installation of additional pollution control technology or may require the purchase of emission allowances. Certain of these provisions are described in more detail below.

On October 27, 1998, the Environmental Protection Agency (EPA) issued a rule requiring 22 Eastern states and the District of Columbia to reduce emissions of NO_X (a precursor of ozone). Among other things, the EPA's rule establishes an ozone season, which runs from May through September, and a NO_X emission budget for each state, including Maryland and Pennsylvania. The EPA rule requires states to implement controls sufficient to meet their NO_X budget by May 30, 2004. Coal-fired power plants are a principal target of NO_X reductions under this initiative.

Many of our generation facilities are subject to NO_X reduction requirements under the EPA rule, including those located in Maryland and Pennsylvania. At the Brandon Shores and Wagner facilities, we installed emission reduction equipment to meet Maryland regulations issued pursuant to EPA's rule. The owners of the Keystone plant in Pennsylvania are installing emissions reduction equipment by July 2003 to meet Pennsylvania regulations issued pursuant to EPA's rule. We estimate our costs for the equipment needed at this plant will be approximately $35 million. Through December 31, 2002, we have spent approximately $26 million.

The EPA established new National Ambient Air Quality Standards for very fine particulates and revised standards for ozone attainment that were upheld after various court appeals. While these standards may require increased controls at some of our fossil generating plants in the future, implementation could be delayed for several years. We cannot estimate the cost of these increased controls at this time because the states, including Maryland, Pennsylvania, and California, still need to determine what reductions in pollutants will be necessary to meet the EPA standards.

The EPA and several states have filed suits against a number of coal-fired power plants in Mid-Western and Southern states alleging violations of the deterioration prevention and non-attainment provisions of the Clean Air Act's new source review requirements. In 2000, and again in 2002, using its broad investigatory powers, the EPA requested information relating to modifications made to our Brandon Shores, Crane, and Wagner plants in Baltimore, Maryland. The EPA also sent similar, but narrower, information requests to two of our newer Pennsylvania waste-coal burning plants. This information is to determine compliance with the Clean Air Act and state implementation plan requirements, including potential application of federal New Source Performance Standards. We have responded to the EPA and as of the date of this report the EPA has taken no further action.

In general, such standards can require the installation of additional air pollution control equipment upon the major modification of an existing plant. Although there have not been any new source review-related suits filed against our facilities, there can be no assurance that any of them will not be the target of an action in the future. Based on the levels 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.

The Clean Air Act requires the EPA to evaluate the public health impacts of emissions of mercury, a hazardous air pollutant, from coal-fired plants. The EPA has decided to control mercury emissions from coal-fired plants. Compliance could be required by approximately 2007. We believe final regulations could be issued in 2004 and would affect all coal-fired boilers. The cost of compliance with the final regulations could be material.

Future initiatives regarding greenhouse gas emissions and global warming continue to be the subject of much debate. The related Kyoto Protocol was signed by the United States but has since been rejected by the President, who instead has asked for an 18% decrease in carbon intensity on a voluntary basis. Future initiatives on this issue and the ultimate effects of the Kyoto Protocol and the President's initiatives on us are unknown at this time. 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 carbon dioxide emissions, a principal greenhouse gas. Our compliance costs with any mandated federal greenhouse gas reductions in the future could be material.

Clean Water Act

Our facilities are subject to a variety of federal and state regulations governing existing and potential water/wastewater and stormwater discharges.

In April 2002, the EPA proposed rules under the Clean Water Act that require that cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts. These rules pertain to existing utilities and non-utility power producers that currently employ a cooling water intake structure and whose flow exceeds 50 million gallons per day. We expect a final action on the proposed rules by February 2004. The proposed rule may require the installation of additional intake screens or other protective measures, as well as extensive site specific study and monitoring requirements. There is also the possibility that the proposed rules may lead to the installation of cooling towers on four of our fossil and both of our nuclear facilities. Our compliance costs associated with the final rules could be material.

Under current provisions of the Clean Water Act, existing permits must be renewed at least every five years, at which time permit 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. Changes to the environmental permits of our coal or other fuel suppliers due to federal or state initiatives may increase the cost of fuel, which in turn could have a significant impact on our operations.

Comprehensive Environmental Response, Compensation and Liability Act (Superfund statute)

This law, or CERCLA, among other things, imposes cleanup requirements for threatened or actual releases of hazardous substances that may endanger public health or welfare of the environment. Under CERCLA, joint and several liability may be imposed on waste generators, site owners and operators and others regardless of fault or the legality of the original disposal activity. Many states have implemented laws similar to CERCLA. Although all waste substances generated by our facilities are generally not regarded as hazardous substances, some products used in the operations and the disposal of such products are governed by CERCLA and similar state statutes.

Metal Bank

In the early 1970s, BGE shipped an unknown number of scrapped transformers to Metal Bank of America, a metal reclaimer in Philadelphia. Metal Bank's scrap and storage yard has been found to be contaminated with oil containing high levels of PCBs (hazardous chemicals frequently used as a fire resistant coolant in electrical equipment). On December 7, 1987, the EPA notified BGE and nine other utilities that they are considered potentially responsible parties (PRPs) with respect to the cleanup of the site. BGE, along with the other PRPs, submitted a remedial investigation and feasibility study to the EPA on October 14, 1994, and the EPA issued its Record of Decision on December 31, 1997. On June 26, 1998, the EPA ordered BGE, the other utility PRPs, and the owner/operator to implement the requirements of the Record of Decision. The utility PRPs have submitted the remedial design to EPA. Based on the Record of Decision, BGE's share of the reasonably possible cleanup costs, estimated to be approximately 15.47%, could be as much as $1.3 million higher than amounts we believe are probable and have recorded as a liability in our Consolidated Balance Sheets. There has been no significant activity with respect to this site since the EPA's Record of Decision in 1997.

Kane and Lombard Streets

Suit was originally filed by the EPA under CERCLA in October 1989 against BGE and several other defendants in the U.S. District Court for the District of Maryland, seeking to recover past and future clean up costs at the Kane and Lombard Street site located in Baltimore City, Maryland. The State of Maryland filed a similar complaint in the same case and court in February 1990. The complaints alleged that BGE arranged for coal fly ash to be deposited on the site. The Court dismissed these complaints in November 1995. Maryland began additional investigation on the remainder of the site for the EPA, but never completed the investigation. BGE, along with three other defendants, agreed to complete a remedial investigation and feasibility study of groundwater contamination around the site in a July 1993 consent order. The remedial investigation report and a draft feasibility study were submitted to the EPA in February 2002. In December 2002, the EPA released its proposed remedy for the site and estimated the total cost for the site to be $6.2 million. Until the EPA finalizes the plan, we cannot estimate BGE's share of the total site cleanup costs, but it is not expected to be material.

68th Street Dump

In July 1999, the EPA notified BGE, along with 19 other entities, that it may be a potentially responsible party at the 68^{th} Street Dump/Industrial Enterprises Site, also known as the Robb Tyler Dump, located in Baltimore, Maryland. The EPA indicated that it is proceeding with plans to conduct a remedial investigation and feasibility study. This site was proposed for listing as a federal Superfund site in January 1999, but the listing has not been finalized. Although our potential liability cannot be estimated, we do not expect such liability to be material based on BGE records showing that it did not send waste to the site.

Spring Gardens

In the past, predecessor gas companies (which were later merged into BGE) manufactured coal gas for residential and industrial use. The Spring Gardens site was once used to manufacture gas from coal and oil. The residue from this manufacturing process was coal tar, previously thought to be harmless but now found to contain a number of chemicals designated by the EPA as hazardous substances.

In late December 1996, BGE signed a consent order with the Maryland Department of the Environment that required it to implement remedial action plans for contamination at and around the Spring Gardens site, located in Baltimore, Maryland. BGE submitted the required remedial action plans, and they have been approved by the Maryland Department of the Environment. Based on these plans, the costs BGE considers to be probable to remedy the contamination are estimated to total $47 million. BGE recorded these costs as a liability in its Consolidated Balance Sheets and deferred these costs, net of accumulated amortization and amounts it recovered from insurance companies, as a regulatory asset. Through December 31, 2002, BGE spent approximately $39 million for remediation at this site.

BGE also is required by accounting rules to disclose additional costs it considers to be less likely than probable, but still "reasonably possible" of being incurred at this site. Because of the results of studies at this site, it is reasonably possible that these additional costs could exceed the $47 million BGE recognized by approximately $14 million.

As a result of CERCLA's no-fault, retroactive liability provisions, we cannot determine whether we will be free from substantial liabilities for other sites in the future.

Employees

Constellation Energy and its subsidiaries had, at December 31, 2002, approximately 8,700 employees. The Central Wayne plant has a partially unionized workforce where approximately 30 employees are represented by the International Union of Operating Engineers. The labor contract with this union expires June 30, 2004. At the Nine Mile Point plant, approximately 700 employees are represented by the International Brotherhood of Electrical Workers, Local 97. The labor contract with this union expires in July 2006 with wages open to negotiation in June 2003. We believe that our relations with both unions are satisfactory, but there can be no assurances that this will continue to be the case.

We discuss several workforce reduction programs in *Item 7. Management's Discussion and Analysis Significant Events* section.

Item 2. Properties

Constellation Energy's corporate offices occupy approximately 85,000 square feet of leased office space in Baltimore, Maryland. The corporate offices for most of our merchant energy business occupy approximately 100,000 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.

We own BGE's principal headquarters building in downtown Baltimore. 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 expire in 2004. These rights-of-way can be renewed during their last year for an additional period of 25 years based on a fair revaluation. Conditions of the grants are satisfactory.

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 affiliates 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 maintain office space throughout North America to support our competitive supply activities.

The following table describes our generating facilities:

Plant	Location	Installed Capacity (MW)	% Owned	Capacity Owned (MW)	Primary Fuel
		(at December 31, 2002)		(at December 31, 2002)	
PJM Platform					
Calvert Cliffs	Calvert Co., MD	1,685	100.0	1,685	Nuclear
Brandon Shores	Anne Arundel Co., MD	1,286	100.0	1,286	Coal
H. A. Wagner	Anne Arundel Co., MD	1,020	100.0	1,020	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	359 (A)	Coal
Conemaugh	Indiana Co., PA	1,711	10.6	181 (A)	Coal
Perryman	Harford Co., MD	360	100.0	360	Oil/Gas
Riverside	Baltimore Co., MD	251	100.0	251	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
Gould Street	Baltimore City, MD	104	100.0	104	Oil/Gas
Philadelphia Road	Baltimore City, MD	64	100.0	64	Oil
Safe Harbor	Safe Harbor, PA	416	66.7	277	Hydro
Total PJM Platform		9,506		6,485	
Plants with Power Purchase Agreements					
Nine Mile Point Unit 1	Scriba, NY	609	100.0	609	Nuclear
Nine Mile Point Unit 2	Scriba, NY	1,148	82.0	941	Nuclear
Oleander	Brevard Co., FL	680	100.0	680	Oil/Gas
University Park	Chicago, IL	300	100.0	300	Gas
Total Plants with Power Purchase Agreements		2,737		2,530	

Plant	Location	Installed Capacity (MW)	% Owned	Capacity Owned (MW)	Primary Fuel
Competitive Supply					
Rio Nogales	Seguin, TX	800	100.0	800	Gas
Other					
Holland Energy	Shelby Co., IL	665	100.0	665	Gas
Big Sandy	Neal, WV	300	100.0	300	Gas
Wolf Hills	Bristol, VA	250	100.0	250	Gas
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	30.3	31	Coal
Jasmin	Kern Co., CA	33	50.0	17	Coal
POSO	Kern Co., CA	33	50.0	17	Coal
Puna I	Hilo, HI	30	50.0	15	Geothermal
Mammoth Lakes G-1	Mammoth Lakes, CA	8	50.0	4	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	3	50.0	2	Geothermal
Soda Lake II	Fallon, NV	13	50.0	7	Geothermal
Stillwater	Fallon, NV	13	50.0	6	Geothermal
Rocklin	Placer Co., CA	24	50.0	12	Biomass
Fresno	Fresno, CA	24	50.0	12	Biomass
Chinese Station	Sonora, CA	22	45.0	10	Biomass
Malacha	Muck Valley, CA	32	50.0	16	Hydro
Central Wayne	Dearborn, MI	22	50.0	11	Municipal Solid Waste
SEGS IV	Kramer Junction, CA	30	12.0	4	Solar
SEGS V	Kramer Junction, CA	30	4.0	1	Solar
SEGS VI	Kramer Junction, CA	30	9.0	3	Solar
Total Other		1,934		1,491	
Total Generating Facilities		14,977		11,306	

(A) Reflects our proportionate interest in and entitlement to capacity from Keystone and Conemaugh, which include 2 megawatts of diesel capacity for Keystone and 1 megawatt of diesel capacity for Conemaugh.

The following table describes our processing facilities:

Plant	Location	Installed Capacity (MW)	% Owned	Capacity Owned (MW)	Primary Fuel
		(at December 31, 2002)		(at December 31, 2002)	

Plant	Location	Installed Capacity (MW)	% Owned	Capacity Owned (MW)	Primary Fuel
A/C Fuels	Hazelton, PA		50.0		Coal Processing
Gary PCI	Gary, IN		24.5		Coal Processing
PC Synfuel VA I	Appalachia, VA		16.7		Synfuel Processing
PC Synfuel WV I	Charleston, WV		16.7		Synfuel Processing
PC Synfuel WV II	Wheelersburg, OH		16.7		Synfuel Processing
PC Synfuel WV III	Mayberry, WV		16.7		Synfuel Processing

Item 3. Legal Proceedings

We discuss our legal proceedings in *Item 7. Management's Discussion and Analysis Business Environment* section and in *Note 11 to Consolidated Financial Statements.*

Item 4. Submission of Matters to Vote of Security Holders

Not applicable.

Executive Officers of the Registrant

Name	Age	Present Office	Other Offices or Positions Held During Past Five Years
Mayo A. Shattuck III	48	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)	Co-Chairman and Co-Chief Executive Officer DB Alex Brown, LLC and Deutsche Banc Securities, Inc., Vice Chairman Bankers Trust Corporation.
E. Follin Smith	43	Senior Vice President and Chief Financial Officer of Constellation Energy (since June 2001) and Senior Vice President and Chief Financial Officer of Baltimore Gas and Electric Company (since January 2002)	Senior Vice President and Chief Financial Officer Armstrong Holdings, Inc.; Vice President and Treasurer Armstrong Holdings, Inc. (filed for bankruptcy under Chapter 11 on December 6, 2000); and Chief Financial Officer General Motors Delphi Chassis Systems.
Thomas V. Brooks	40	President of Constellation Power Source, Inc. (since October 2001)	Vice President of Business Development and Strategy Constellation Energy; and Vice President Goldman Sachs.
Frank O. Heintz	59	President and Chief Executive Officer of Baltimore Gas and Electric Company (since July 2000)	Executive Vice President, Utility Operations BGE; and Vice President, Gas BGE.
Michael J. Wallace	55	President of Constellation Generation Group, LLC (since January 2002)	Managing Director and Member Barrington Energy Partners; and Senior Vice President Commonwealth Edison.
Thomas F. Brady	53	Senior Vice President, Corporate Strategy and Development of Constellation Energy (since May 2002)	Vice President, Corporate Strategy and Development Constellation Energy; Vice President, Retail Services BGE; and Vice President, Customer Service and Distribution BGE.

Paul J. Allen	51	Vice President, Corporate Affairs of Constellation Energy (since May 2001)	Senior Vice President and Group Head Ogilvy Public Relations.
Kathleen A. Chagnon	43	Vice President, General Counsel, and Secretary of Constellation Energy (since August 2002)	Vice President, Corporate Group General Counsel The St. Paul Companies, Inc.; and Assistant Vice President and Associate Group Counsel USF&G Corporation.
John R. Collins	45	Vice President and Chief Risk Officer of Constellation Energy (since December 2001)	Managing Director Finance Constellation Power Source Holdings, Inc.; and Senior Financial Officer Constellation Power Source, Inc.
Mark P. Huston	39	Vice President, Corporate Strategy and Development of Constellation Energy (since May 2002)	Manager, Corporate Strategy & Development Constellation Energy; Project Manager, Restructuring Project BGE; and Director, Gas Business Development BGE.
Marc C. Ugol	44	Vice President, Human Resources of Constellation Energy (since October 2002)	Senior Vice President, Human Resources and Administration Tellabs, Inc.; and Senior Vice President, Human Resources Platinum Technology International.

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 February 28, 2003, there were 50,914 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 2003, we announced an increase in our quarterly dividend from 24 cents to 26 cents per share on our common stock payable April 1, 2003 to holders of record on March 10, 2003. This is equivalent to an annual rate of $1.04 per share.

Quarterly dividends were declared on our common stock during 2002 and 2001 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 7.16% Deferrable Interest Subordinated Debentures due June 30, 2038, and any deferred interest remains unpaid; or

all dividends (and any redemption payments) due on BGE's preference stock have not been paid.

Common Stock Dividends and Price Ranges

	2002			2001		
		Price*			Price*	
	Dividend Declared	High	Low	Dividend Declared	High	Low
First Quarter	$ .24	$ 31.18	$ 26.16	$ .12	$ 44.65	$ 34.69
Second Quarter	.24	32.38	27.65	.12	50.14	40.10
Third Quarter	.24	29.85	21.51	.12	43.80	22.85
Fourth Quarter	.24	29.02	19.30	.12	28.21	20.90
Total	$ .96			$ .48		

* Based on New York Stock Exchange Composite Transactions.

Item 6. Selected Financial Data

Constellation Energy Group, Inc. and Subsidiaries

	2002	2001	2000	1999	1998
	(Dollar amounts in millions, except per share amounts)				
Summary of Operations					
Total Revenues	**$ 4,703.0**	$ 3,878.8	$ 3,774.4	$ 3,830.9	$ 3,382.5
Total Expenses	**3,878.1**	3,527.2	3,009.9	3,081.0	2,647.9
Net Gain on Sales of Investments and Other Assets	**261.3**	6.2	78.1	10.0	3.9
Income From Operations	**1,086.2**	357.8	842.6	759.9	738.5
Other Income	**30.5**	1.3	4.2	7.9	5.7
Fixed Charges	**281.5**	238.8	271.4	255.0	260.6
Income Before Income Taxes	**835.2**	120.3	575.4	512.8	483.6
Income Taxes	**309.6**	37.9	230.1	186.4	177.7
Income Before Extraordinary Item and Cumulative Effect of	**525.6**	82.4	345.3	326.4	305.9

	2002	2001	2000	1999	1998
Change in Accounting Principle					
Extraordinary Loss, Net of Income Taxes				(66.3)	
Cumulative Effect of Change in Accounting Principle, Net of Income Taxes		8.5			
Net Income	**$ 525.6**	$ 90.9	$ 345.3	$ 260.1	$ 305.9
Earnings Per Common Share and					
Earnings Per Common Share Assuming Dilution Before Extraordinary Item and Cumulative Effect of Change in Accounting Principle	**$ 3.20**	$ .52	$ 2.30	$ 2.18	$ 2.06
Extraordinary Loss				(.44)	
Cumulative Effect of Change in Accounting Principle		.05			
Earnings Per Common Share and					
Earnings Per Common Share Assuming Dilution	**$ 3.20**	$ .57	$ 2.30	$ 1.74	$ 2.06
Dividends Declared Per Common Share	**$ .96**	$ .48	$ 1.68	$ 1.68	$ 1.67
Summary of Financial Condition					
Total Assets	**$ 14,128.9**	$ 14,109.4	$ 12,939.3	$ 9,745.1	$ 9,434.1
Short-Term Borrowings	**$ 10.5**	$ 975.0	$ 243.6	$ 371.5	$
Current Portion of Long-Term Debt	**$ 426.2**	$ 1,406.7	$ 906.6	$ 808.3	$ 541.7
Capitalization					
Long-Term Debt	**$ 4,613.9**	$ 2,712.5	$ 3,159.3	$ 2,575.4	$ 3,128.1
Minority Interests	**105.3**	101.7	97.7	95.2	2.0
Preference Stock Not Subject to Mandatory Redemption	**190.0**	190.0	190.0	190.0	190.0
Common Shareholders' Equity	**3,862.3**	3,843.6	3,174.0	3,017.5	2,995.9
Total Capitalization	**$ 8,771.5**	$ 6,847.8	$ 6,621.0	$ 5,878.1	$ 6,316.0
Financial Statistics at Year End					

	2002	2001	2000	1999	1998
Ratio of Earnings to Fixed Charges	**3.33**	1.18	2.78	2.87	2.60
Book Value Per Share of Common Stock	**$ 23.44**	$ 23.48	$ 21.09	$ 20.17	$ 20.08

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

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

Baltimore Gas and Electric Company and Subsidiaries

	2002	2001	2000(A)	1999	1998
			(Dollar amounts in millions)		
Summary of Operations					
Total Revenues	**$ 2,547.3**	$ 2,720.7	$ 2,746.8	$ 3,092.2	$ 3,386.4
Total Expenses	**2,181.0**	2,408.9	2,334.4	2,387.9	2,647.9
Income From Operations	**366.3**	311.8	412.4	704.3	738.5
Other Income	**10.7**	0.4	7.5	8.4	5.7
Fixed Charges	**140.6**	154.6	184.0	205.9	238.8
Income Before Income Taxes	**236.4**	157.6	235.9	506.8	505.4
Income Taxes	**93.3**	60.3	92.4	178.4	177.7
Income Before Extraordinary Item	**143.1**	97.3	143.5	328.4	327.7
Extraordinary Loss, Net of Income Taxes				(66.3)	
Net Income	**143.1**	97.3	143.5	262.1	327.7
Preference Stock Dividends	**13.2**	13.2	13.2	13.5	21.8
Earnings Applicable to Common Stock	**$ 129.9**	$ 84.1	$ 130.3	$ 248.6	$ 305.9
Summary of Financial Condition					
Total Assets	**$ 4,779.9**	$ 4,954.5	$ 4,654.2	$ 7,272.6	$ 9,434.1
Short-Term Borrowings	**$**	$	$ 32.1	$ 129.0	$
Current Portion of Long-Term Debt	**$ 420.7**	$ 666.3	$ 567.6	$ 523.9	$ 541.7
Capitalization					
Long-Term Debt	**$ 1,499.1**	$ 1,821.7	$ 1,864.4	$ 2,206.0	$ 3,128.1

	2002	2001	2000(A)	1999	1998
Minority Interest	**19.4**	5.0	4.6	4.2	1.1
Preference Stock Not Subject to Mandatory Redemption	**190.0**	190.0	190.0	190.0	190.0
Common Shareholder's Equity	**1,461.7**	1,131.4	802.3	2,355.4	2,981.5
Total Capitalization	**$ 3,170.2**	$ 3,148.1	$ 2,861.3	$ 4,755.6	$ 6,300.7

Financial Statistics at Year End

	2002	2001	2000(A)	1999	1998
Ratio of Earnings to Fixed Charges	**2.66**	1.99	2.27	3.45	2.94
Ratio of Earnings to Fixed Charges and Preferred and Preference Stock Dividends	**2.31**	1.75	2.03	3.14	2.60

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

(A) In July 2000, BGE transferred its generation assets, net of associated liabilities, to our merchant energy business as a result of the deregulation of electric generation.

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

Introduction

Constellation Energy Group, Inc. (Constellation Energy) is a North American 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 "utility business" are to BGE.

Our merchant energy business is a competitive provider of energy solutions for large customers in North America. 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 activities) of, and providing other risk management activities for various customers, such as utilities, municipalities, cooperatives, retail aggregators, and large commercial and industrial customers. These load-serving activities typically occur in regional markets in which end use customer electricity rates have been deregulated and thereby separated from the cost of generation supply.

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

Our other nonregulated businesses:

- design, construct, and operate single-site heating, cooling, and cogeneration facilities for commercial and industrial customers,
- provide home improvements, service heating, air conditioning, plumbing, electrical, and indoor air quality systems, and provide electric and natural gas retail marketing, and

own and operate a district cooling system for commercial customers in the City of Baltimore, Maryland.

In addition, we own several investments that we do not consider to be core operations. These include financial investments, real estate projects, and interests in a Latin American distribution project and in a fund that holds interests in two South American energy projects. We sold certain non-core assets in 2002 and closed our retail merchandise stores in December 2002.

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

- factors which affect our businesses,
- our earnings and costs in the periods presented,
- changes in earnings and costs between periods,
- sources of earnings,
- impact of these factors on our overall financial condition,
- expected future expenditures for capital projects, 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 2002, 2001, and 2000. We analyze and explain the differences between periods in the specific line items of the Consolidated Statements of Income.

Effective July 1, 2000, electric generation was deregulated in Maryland and BGE transferred all of its generation assets and related liabilities at book value to our merchant energy business. As a result, the financial results of the electric generation portion of our business are included in the merchant energy business beginning July 1, 2000. Prior to July 1, 2000, the financial results of electric generation were included in BGE's regulated electric business. We discuss the deregulation of electric generation in the *Electric Competition Maryland* section.

Critical Accounting Policies

Our discussion and analysis of financial condition and results of operations are 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 assets and liabilities in our Consolidated Balance Sheets at the dates of the financial statements,
- our disclosure of contingent assets and liabilities at the dates of the financial statements, and
- our reported amounts of revenues and expenses in our Consolidated Statements of Income during the reporting periods.

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 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 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*.

Revenue Recognition/Mark-to-Market Method of Accounting

Our merchant energy business engages in origination and risk management activities using contracts for energy, other energy-related commodities, and related derivative contracts. We record merchant energy business revenues using two methods of accounting: accrual accounting and mark-to-market accounting. We describe our use of accrual accounting in more detail in *Note 1*.

On October 25, 2002, the Emerging Issues Task Force (EITF) reached a consensus on Issue 02-3, *Recognition and Reporting of Gains and Losses on Energy Trading Contracts Under EITF Issues No. 98-10 and No. 00-17*. EITF 02-3 affects how we apply the mark-to-market method of accounting. We describe our accounting for energy contracts and the impact of EITF 02-3 below.

We use mark-to-market accounting for energy trading activities and for derivatives and other contracts for which we are not permitted to use accrual accounting or hedge accounting. These mark-to-market activities include derivative and (prior to EITF 02-3) non-derivative contracts for energy and other energy-related commodities. Under the mark-to-market method of accounting, we record the fair value of energy contracts 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 on a net basis in "Nonregulated revenues" in our Consolidated Statements of Income.

At December 31, 2002, mark-to-market energy assets and liabilities consisted of a combination of energy and energy-related derivative and non-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 reserves to reflect uncertainties associated with certain estimates inherent in the determination of fair value that are 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 risks for which we record reserves and determining the level of such reserves and changes in those levels.

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

Close-out reserve this reserve represents the estimated cost to close out or sell to a third-party open mark-to-market positions. This reserve has the effect of valuing "long" positions at the bid price and "short" positions at the offer price. We compute this reserve based on our estimate of the bid/offer spread for each commodity and option price and the absolute quantity of our open positions for each year. Effective July 1, 2002, to the extent that we are not able to obtain market information for similar contracts, the close-out reserve is equivalent to the initial contract margin, thereby resulting in no gain or loss at inception. The level of total close-out reserves 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.

Credit-spread adjustment for risk management purposes, we compute the value of our mark-to-market 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 assets to reflect the credit-worthiness of each individual counterparty based upon published credit ratings, where available, or equivalent internal credit ratings and associated default probability percentages. We compute this reserve by applying the appropriate default probability percentage to our outstanding credit exposure, net of collateral, for each counterparty. The level of this reserve 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. Changes in market prices will 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. 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.

On October 25, 2002, the EITF reached a consensus on Issue 02-3 that changed the accounting for certain energy contracts. The main provisions of Issue 02-3 are as follows:

EITF 02-3 prohibits the use of mark-to-market accounting for any energy-related contracts that are not derivatives. Any contracts subject to EITF 02-3 must be accounted for on the accrual basis and recorded in the income statement gross rather than net upon application of EITF 02-3. This change applied immediately to new contracts executed after October 25, 2002 and applied to existing non-derivative energy-related contracts beginning January 1, 2003.

We are required to report the impact of initially applying EITF 02-3 as the cumulative effect of a change in accounting principle.

The EITF minutes on Issue 02-3 indicate that an entity should not record unrealized gains or losses at the inception of derivative contracts unless the fair value of the contracts is evidenced by observable market data.

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Applying EITF 02-3 will not affect our cash flows or our accounting for new load-serving contracts for which we have been using accrual accounting since early 2002. Additionally, we continued to mark existing non-derivative energy-related contracts to market for the remainder of 2002. However, EITF 02-3 requires us to record a non-cash, cumulative effect adjustment to convert these non-derivative mark-to-market contracts to accrual accounting no later than January 1, 2003.

We reviewed our portfolio of mark-to-market contracts to identify the contracts that are subject to the requirements of EITF 02-3. The primary contracts that are affected are our full requirements load-serving contracts and unit-contingent power purchase contracts, which are not derivatives. The majority of these contracts are in Texas and New England and were entered into prior to the shift to accrual accounting earlier in 2002. Additionally, we reviewed derivatives we use as supply sources and hedges of contracts that are subject to EITF 02-3. To the extent permitted by Statement of Financial Accounting Standards (SFAS) No. 133, *Accounting for Derivative Instruments and Hedging Activities,* as amended, we designated derivative contracts used to fulfill our load-serving contracts as either normal purchases or cash flow hedges under SFAS No. 133 effective January 1, 2003.

We summarize the impact on our Consolidated Balance Sheets of applying EITF 02-3 on January 1, 2003 as follows:

	Assets	Liabilities	Net
		(In millions)	
Mark-to-market energy contracts			
Current	$ 144.0	$ 94.1	$ 49.9
Noncurrent	1,348.2	881.5	466.7
Total	1,492.2	975.6	516.6
Other			
Current	85.7	56.8	28.9
Noncurrent	24.2	2.5	21.7
Total	109.9	59.3	50.6
Balance at December 31, 2002	1,602.1	1,034.9	567.2
Impact of EITF 02-3 Adoption			

	Assets	Liabilities	Net
Non-derivative net asset reversed as cumulative effect of a change in accounting principle			
Mark-to-market energy contracts	(494.7)	(119.8)	(374.9)
Other	(109.9)	(59.3)	(50.6)
Total non-derivative net asset reversed as cumulative effect of a change in accounting principle	(604.6)	(179.1)	(425.5)
Derivatives designated as hedges	(88.3)	(94.4)	6.1
Derivatives designated as normal purchases and sales	(192.6)	(128.3)	(64.3)
Mark-to-market derivatives remaining after adoption of EITF 02-3 on January 1, 2003	$ 716.6	$ 633.1	$ 83.5

On January 1, 2003, we recorded the $425.5 million non-derivative net asset removed from our Consolidated Balance Sheets as a cumulative effect of a change in accounting principle, which will reduce our 2003 net income by $263 million. The $425.5 million represents $374.9 million of non-derivative contracts recorded as "Mark-to-market energy assets and liabilities" and $50.6 million of "Other assets and liabilities" from the re-designation of Texas contracts to accrual accounting earlier in 2002. The fair value of these contracts will be recognized in earnings as power is delivered.

Additionally, on January 1, 2003, we reclassified the fair value of derivatives designated as hedges as "Risk management assets and liabilities" in the balance sheet and will account for these hedges in accordance with the provisions of SFAS No. 133. At that time, we also reclassified the fair value of derivatives designated as normal purchases and normal sales as "Other assets and liabilities" in the balance sheet and will account for these contracts on the accrual basis, with the fair value amortized into earnings over the lives of the underlying contracts.

We cannot predict the impact of applying the provisions of EITF 02-3 in the future. Those provisions prohibit mark-to-market accounting for gains at the inception of new non-derivative energy contracts, require accrual accounting for those contracts, and limit the ability to record gains at the inception of new derivative contracts. We believe that our shift to accrual accounting for new physical delivery transactions in early 2002 is consistent with the requirement of EITF 02-3 to use accrual accounting for non-derivative contracts.

However, the impact of applying EITF 02-3 in the future will be 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 derivative contracts that serve as economic hedges but do not meet the accounting requirements to qualify for normal purchase and 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 or current market transactions.

While we cannot predict the ongoing impact of applying EITF 02-3, the timing of recognizing earnings on new transactions will change. In general, earnings on new transactions will no longer be recognized at the inception of the transactions under mark-to-market accounting because they will be recognized over the term of the transaction. As a result, while total earnings over the term of a transaction will be unchanged, we expect that our reported earnings for contracts subject to EITF 02-3 will generally match the cash flows from those contracts more closely and may be less volatile under accrual accounting than under mark-to-market accounting, which reflects changes in fair value of contracts when they occur rather than when products are delivered and costs are incurred.

Alternatively, other comprehensive income may have greater fluctuations after we apply EITF 02-3 because of a larger number of derivative contracts that we designated for hedge accounting under SFAS No. 133, but these fluctuations will not affect earnings or cash flows. Additionally, because we will record revenues and costs on a gross basis under accrual accounting, our revenues and costs could increase, but our earnings will not be affected by gross versus net reporting.

We discuss the impact of mark-to-market accounting on our financial results in the *Results of Operations Merchant Energy Business* section.

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

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 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 would be as follows:

- 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 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 requires 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 involves judgement surrounding the inherent uncertainty of future cash flows.

In order to estimate an asset's future cash flows, we will consider historical cash flows, as well as reflect our understanding of the extent to which future cash flows will be either similar to or different from past experience based on all available evidence. 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 establish the cash flows.

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 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 to be disposed of by sale under SFAS No. 144, an impairment loss shall be recognized to the extent their carrying amount exceeds their fair value, including costs to sell.

The estimation of fair value under SFAS No. 144, whether in conjunction with an asset to be held and used or with an asset to be disposed of by sale, also involves estimation and judgment. We consider quoted market prices in active markets to the extent they are available. In the absence of such information, we may look to 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 and 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 also are 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 for these investments. The standard for determining whether an impairment must be recorded under APB No. 18 is whether the investment has experienced a loss in value that is considered an "other than a temporary" decline in value.

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

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Significant Events

2002

In 2002, we recorded the following special items in earnings:

	Pre-Tax	After-Tax
	(In millions)	
Workforce reduction costs:		
Costs associated with 2001 programs	$ (50.8)	$ (30.8)
Costs associated with programs initiated in 2002	(12.0)	(7.2)
Total workforce reduction costs	(62.8)	(38.0)
Impairment losses and other costs:		
Impairments of investments in qualifying facilities and power projects	(14.4)	(9.9)
Costs associated with exit of BGE Home merchandise stores	(9.0)	(6.1)
Impairments of real estate and international investments	(1.8)	(1.2)
Total impairment losses and other costs	(25.2)	(17.2)
Net gain on sales of investments and other assets	261.3	166.7
Total special items	$ 173.3	$ 111.5

We also discuss these special items in *Note 2*.

Workforce Reduction Costs

During 2002, we incurred costs related to workforce reduction efforts initiated in the fourth quarter of 2001 as discussed in the *2001* section and additional initiatives undertaken in 2002. We discuss these costs in more detail below.

Costs Associated with 2001 Programs
In 2002, we recorded $63.7 million of net workforce reduction costs associated with our 2001 workforce initiatives as discussed below. The $63.7 million included $50.8 million recognized as expense, of which BGE recognized $33.8 million. The remaining $12.9 million was recognized by BGE as a regulatory asset related to its gas business.

We recorded $52.9 million when 308 employees elected the age 50 to 54 Voluntary Special Early Retirement Program (VSERP).

We reversed $17.8 million of the $25.1 million involuntary severance accrual that was recorded in 2001 to reflect the employees that elected the age 50 to 54 VSERP and whose costs were included in that program. Ultimately, we involuntarily severed 129 employees that resulted in a total cost for the involuntary severance program of $7.3 million.

We recorded $29.6 million of settlement charges related to our pension plans under SFAS No. 88, *Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits*. These charges reflect the recognition of actuarial gains and losses associated with employees who have retired and taken their pension in the form of a lump-sum payment. Under SFAS No. 88, the settlement charge could not be recognized until lump-sum pension payments exceeded annual pension plan service and interest cost, which occurred in 2002.

We recorded a $1.6 million expense associated with deferred payments to employees eligible for the VSERP.

Partially offsetting these costs, we reversed approximately $2.6 million of previously accrued workforce reduction costs primarily as a result of the reversal of education and outplacement assistance benefits we accrued that employees did not utilize to the extent expected.

Costs Associated with 2002 Programs
In 2002, we recorded $12.0 million of expenses for anticipated involuntary severance costs in accordance with EITF 94-3, *Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)* associated with new workforce reduction initiatives as follows:

We recorded $8.5 million for workforce reduction costs for the severance of 120 employees at Calvert Cliffs Nuclear Power Plant (Calvert Cliffs).

We recorded $1.6 million of workforce reduction costs for the severance of 27 employees in our information technology organization. BGE recorded $0.6 million of this amount.

We recorded $1.9 million of workforce reduction costs for the severance of 20 employees in our legal organization. BGE recorded $0.9 million of this amount.

Ongoing Impacts
As a result of our workforce reduction programs and other process improvements, we expect to realize cost savings from productivity initiatives of approximately $65 million in 2003.

Impairment Losses and Other Costs

Investments in Qualifying Facilities and Power Projects
Our merchant energy business recorded impairment losses on certain of the investments in qualifying facilities and power projects totaling $14.4 million under the provisions of APB No. 18. The provisions of APB No. 18 require that an impairment loss be recognized when an investment experiences a loss in value that is other than temporary as discussed in our *Critical Accounting Policies* section.

During the third quarter of 2002, we performed an analysis of whether any of the investments were impaired. As a result of our analysis, we concluded that the declines in value of particular investments in certain qualifying facilities and power projects were other than temporary in nature under the provisions of APB No. 18 and we recognized the following losses in 2002:

We recognized a $5.2 million other than temporary decline in value of our investment in a partnership that owns a geothermal project in Nevada. This project experienced a well implosion and we believe that the expected cash flows from the project will not be sufficient to recover our equity interest in that partnership.

We recognized a $2.6 million other than temporary decline in value of our investment in a fuel processing site in Pennsylvania where the expected cash flows from a sublease are no longer expected to be sufficient to recover our lease costs associated with this site.

We recognized a $6.6 million other than temporary decline in value of our investment in a partnership that owns a waste burning power project in Michigan.

At December 31, 2002, our investment in qualifying facilities and domestic power projects consisted of the following:

Project Type	**Book Value**
	(In millions)
Geothermal	$ 151.4
Coal	133.9
Hydroelectric	62.6
Biomass	52.6
Fuel Processing	23.2
Solar	10.5
Total	$ 434.2

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* section. 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.

We have an investment in a partnership that owns a geothermal project with a book value of $99.0 million at December 31, 2002. Currently, the project is not generating at its designed capacity. The project is drilling wells at this site to restore the generation and we expect the geothermal resource to be sufficient to enable the project to generate adequate cash flows over the life of this project to recover our equity interest in that investment. However, should current or future well drilling at this site prove to be unsuccessful or become uneconomic causing us not to make future investments in this partnership, our investment in this partnership could become impaired under the provisions of APB No. 18 and any losses recognized could be material.

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 electric corporations to identify a separate rate component to fund the development of renewable resources technologies, including solar, biomass, and wind facilities. In addition, recently enacted legislation in California requires that each electric corporation 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 legislation also requires the California Energy Commission to award supplemental energy payments to electric corporations 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.

Closing of BGE Home Retail Merchandise Stores
In September 2002, we announced our decision to close our BGE Home retail merchandise stores. In connection with that decision, we recognized approximately $9.5 million in exit costs. We recognized $2.9 million related to expected severance costs for 93 employees and $2.9 million of costs in connection with the termination of leases for the eight stores and other exit costs in accordance with EITF 94-3.

We also recognized $3.2 million for the write-off of unamortized leasehold improvements in accordance with SFAS No. 144, and $0.5 million for the write-down of inventory to a lower-of-cost-or-market valuation in accordance with Accounting Research Bulletin No. 43, *Restatement and Revision of Accounting Research Bulletins*. The $0.5 million is included in "Operating expenses" in our Consolidated Statements of Income.

Real Estate and International Investments
As discussed in the *2001* section, we changed our strategy from an intent to hold to an intent to sell for certain of our non-core assets in 2001. During 2002, we determined that the fair value of several real estate projects and our investment in a South American generation project declined below their respective book values due to deteriorating market conditions for these projects. Accordingly, we recorded losses that totaled $1.8 million for these projects in accordance with SFAS No. 144 and APB No. 18. In 2002, we sold our investment in a South American generation project for approximately book value.

Net Gain on Sales of Investments and Other Assets

In February 2002, Reliant Resources, Inc. acquired all of the outstanding shares of Orion Power Holdings, Inc. (Orion) for $26.80 per share, including the shares we owned of Orion. We received cash proceeds of $454.1 million and recognized a gain of $255.5 million on the sale of our investment.

In the fourth quarter of 2001, we announced our decision to focus efforts and capital on core domestic energy businesses and undertook a plan to sell a number of non-core businesses and investments. In 2002, we made further progress on this initiative, and recognized approximately $5.8 million in net gains from the sale of several non-core assets including:

- Our other nonregulated businesses recognized gains totaling $6.7 million on the sale of several parcels of real estate and financial investments.
- In October 2002, we sold all of our 18 senior-living facilities for $77.2 million that represents a combination of cash and the assumption by the buyer of existing mortgages. Our other nonregulated businesses recognized a $2.8 million gain on the sale of our entire ownership interest in these facilities.
- Our merchant energy business recognized a $2.3 million gain on the sale of a discontinued wind-powered development project.
- In 2001, our merchant energy business recognized an impairment loss on four turbines, associated with a discontinued development program as discussed in the *2001* section. Since that time, many other companies canceled development projects and the market values for turbines have declined significantly. Orders for three of the four turbines were canceled with termination fees paid to the manufacturer consistent with the amount recognized in December 2001. The fourth turbine-generator set was sold during 2002 for $6.0 million below its book value.

In addition, we sold all of our Corporate Office Properties Trust (COPT) equity-method investment in 2002, approximately 8.9 million shares, as part of a public offering. We received cash proceeds of $101.3 million on the sale, which approximated the book value of our investment.

Acquisitions

NewEnergy
On September 9, 2002, we completed our purchase of AES NewEnergy, Inc. from AES Corporation. Subsequent to the acquisition, we renamed AES NewEnergy, Inc. as Constellation NewEnergy, Inc. (NewEnergy). NewEnergy is a leading national provider of electricity, natural gas, and energy services, serving approximately 4,300 megawatts (MW) of load associated with large commercial and industrial customers in

competitive energy markets including the Northeast, Mid-Atlantic, Midwest, Texas and California. We acquired 100% ownership of NewEnergy for cash of $250.3 million including $1.4 million of direct costs associated with the acquisition. We acquired cash of $45.5 million as part of the purchase. We describe the net assets acquired in *Note 14*. We include the results of NewEnergy in our merchant energy business segment beginning on the date of acquisition.

Alliance

On December 31, 2002, we purchased Alliance Energy Services, LLC and Fellon-McCord Associates, Inc. (collectively, Alliance) from Allegheny Energy, Inc. These businesses provide gas supply and transportation services and energy consulting services to large commercial and industrial businesses primarily in the Midwest region, but also in other competitive energy markets including the Northeast, Mid-Atlantic, Texas and California regions. We acquired 100% ownership of these companies for a note payable of $21.2 million that was settled in cash on January 2, 2003. We acquired cash of $4.6 million as part of the purchase. We describe the net assets acquired in *Note 14*. We will include the operating results of Alliance in our merchant energy business segment in 2003.

Renegotiations of our High Desert Power Contract

We are currently leasing and supervising the construction of the High Desert Power Project. The project is scheduled for completion in mid-2003. In April 2002, we amended our High Desert Power Project long-term power sales agreement with the State of California to provide revised pricing and more flexibility in the amount of electricity purchased from the plant by the California Department of Water Resources (CDWR) and the timing of such purchases. This amended agreement provides the State of California with the flexibility they desired, while preserving our overall economics and reducing our regulatory, fuel, and legal risks.

The contract is a "tolling" structure, under which the CDWR will pay a fixed amount of $12.1 million per month and provides CDWR the right, but not the obligation, to purchase power from the High Desert Power Project at a price linked to the variable cost of production. During the term of the contract, which runs for seven years and nine months from the commercial operation date of the plant, the High Desert Power Project will provide energy exclusively to the CDWR.

We also signed a comprehensive settlement agreement with the CDWR, the California Energy Oversight Board (EOB), the CPUC, the California Attorney General, and the Governor of California by which each of these parties agreed to release claims against us arising out of the original and renegotiated contracts.

Under the settlement agreement, the California parties filed with the Federal Energy Regulatory Commission (FERC) to withdraw us from the regulatory complaint filed at the FERC by the CPUC and EOB against all holders of long-term power contracts. We agreed to pay $1.25 million into a school and public buildings energy retrofit fund and another $1.25 million to the Attorney General's office in order to conclude this overall comprehensive settlement package.

We discuss our High Desert project in more detail in the *Capital Resources* section.

Generating Facilities Commence Operations

The following generating facilities commenced operations during the second half of 2002. Our origination and risk management operation manages the output of these plants.

Plant	Location	Capacity (MW)	Type	Primary Fuel
Rio Nogales	Seguin, TX	800	Combined Cycle	Natural Gas
Oleander	Brevard Co., FL	680	Combustion Turbine	Natural Gas
Holland Energy	Shelby Co., IL	665	Combined Cycle	Natural Gas

Pension Plan

At December 31, 2002, we recorded an after-tax charge to equity of $118 million as a result of increasing our additional minimum pension liability. We discuss this in more detail in *Note 6*.

As a result of declines in the financial markets, our actual return on pension plan assets was a loss of approximately 10% for the year ended December 31, 2002. We assume an expected return on pension plan assets of 9% for the purpose of computing annual net periodic pension expense. We determined our assumption for expected return on pension plan assets in accordance with SFAS No. 87, *Employers Accounting for Pensions*. This assumption reflects our targeted long-term investment allocation of 65% equities and 35% fixed income securities for our pension plan assets. We set the level of this assumed return based on a review of average, actual returns for these categories of investments over a long-term period. Some years our actual return on pension assets will exceed the 9% expected return, resulting in an actuarial gain; and some years our actual return will fall short of the 9% expected return, resulting in an actuarial loss.

These 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. In 2002, we contributed $152 million to our pension plans, which included $80 million to the Constellation Energy qualified pension plan and amounts received from the sellers of Nine Mile Point to the Nine Mile Point pension plan. As of the date of this report, we contributed an additional $111 million to our pension plans in 2003.

Certain Relationships

Thomas F. Brady, a Senior Vice President of Constellation Energy is a trustee of COPT. Constellation Energy sold some of its real estate holdings to COPT in 2002 for an aggregate price of less than $5 million. Constellation Energy sold, and anticipates selling, additional real estate holdings to COPT in 2003 for an aggregate price of less than $35 million. The real estate sales were made, and future sales will be made, on an arm's length basis.

2001

In 2001, we recorded the following special items in earnings:

	Pre-Tax	After-Tax
	(In millions)	
Workforce reduction costs:		
Voluntary termination benefits VSERP	$ (70.1)	$ (42.5)
Settlement and curtailment charges	(16.3)	(9.9)
Involuntary severance accrual	(19.3)	(11.7)
Total workforce reduction costs	(105.7)	(64.1)
Contract termination related costs	(224.8)	(139.6)
Impairment losses and other costs:		
Cancellation of domestic power projects	(46.9)	(30.5)
Impairments of real estate, senior-living, and international investments	(107.3)	(69.7)
Reduction of financial investment	(4.6)	(2.8)
Total impairment losses and other costs	(158.8)	(103.0)
Net gain on the sales of investments and other assets	6.2	1.9
Total special items	$ (483.1)	$ (304.8)

We also discuss these special items in *Note 2*.

Workforce Reduction Costs

In the fourth quarter of 2001, we undertook several measures to reduce our workforce through both voluntary and involuntary means. The purpose of these programs was to reduce our operating costs to become more competitive. As part of this initiative, several companies, including our merchant energy business and BGE, announced several workforce reduction initiatives to provide enhanced retirement benefits to certain eligible participants that elected to retire in 2002 and other involuntary severance programs.

As a result, we recorded $105.7 million of expenses related to these programs during the fourth quarter of 2001. BGE recorded $57.0 million of this amount as expense relating to its electric and gas businesses. BGE also recorded $19.5 million on its balance sheet as a regulatory asset of its gas business.

Contract Termination Related Costs

We announced the termination of our power business services agreement with Goldman Sachs & Co. (Goldman Sachs) in 2001. We paid Goldman Sachs a total of $355 million, representing $196 million to terminate the power business services agreement with our origination and risk management operation and $159 million previously recognized as a payable for services rendered under the agreement. We issued commercial paper and borrowed under our existing bank lines to fund this payment. In the fourth quarter of 2001, we recognized expenses of approximately $224.8 million related to the termination of the contract with Goldman Sachs.

Impairment Losses and Other Costs

In the fourth quarter of 2001, our merchant energy business recorded impairments of $46.9 million primarily due to the termination of all planned development projects not under construction, including projects in Texas, California, Florida, and Massachusetts, and due to a decline in value of an investment in

a power project in Michigan. We decided to terminate our development projects due to the expected excess generation capacity in most domestic markets and the significant decline in the forward market prices of electricity. The impairments included costs associated with four turbines no longer expected to be placed in service.

In the fourth quarter of 2001, our other nonregulated businesses recorded $107.3 million in impairments of certain non-core assets as follows:

- We decided to sell six real estate projects without further development and our senior-living facilities.
- We decided to accelerate the exit strategies for two other real estate projects that we will continue to hold and own over the next several years.
- We decided to accelerate the exit strategy for the investment in a distribution company in Panama.
- There was an other than temporary decline in value in our equity-method Bolivian investment due to a deterioration in our investment's position in the Bolivian capacity market.

In addition, our financial investments business recorded a $4.6 million reduction of its investment in an aircraft due to the decline in value of used airplanes as a result of the September 11, 2001 terrorist attacks and the general downturn in the aviation industry.

Net Gain on the Sales of Investments and Other Assets

During 2001, our other nonregulated businesses recognized a $49.5 million gain on the sale of non-core assets, including a $14.9 million gain on the sale of one million shares of our Orion investment and $34.6 million on the sales of other financial investments.

In addition, on November 8, 2001, we sold our Guatemalan power plant operations to an affiliate of Duke Energy International, L.L.C., the international business unit of Duke Energy. Through this sale, Duke Energy acquired Grupo Generador de Guatemala y Cia., S.C.A., which owns two generating plants at Esquintla and Lake Amatitlan in Guatemala. The combined capacity of the plants is 167 megawatts.

We decided to sell our Guatemalan operations to focus our efforts on our core North American energy businesses. As a result of this transaction, we are no longer committed to making significant future capital investments in this non-core operation. We recorded a loss of $43.3 million in the fourth quarter of 2001 resulting from this sale.

Nine Mile Point

On November 7, 2001, we completed our purchase of the Nine Mile Point Nuclear Station (Nine Mile Point) located in Scriba, New York. Nine Mile Point Nuclear Station, LLC, a subsidiary of Constellation Nuclear, purchased 100 percent of Nine Mile Point Unit 1 and 82 percent of Unit 2 for cash of $382.7 million including settlement costs and a sellers' note of $388.1 million to be repaid over five years with an interest rate of 11.0%. This note was prepaid in April 2002. The sellers also transferred approximately $442 million in decommissioning funds. As a result of this purchase, we own 1,550 megawatts of Nine Mile Point's 1,757 megawatts of total generating capacity.

We sell 90% of our share of Nine Mile Point's output, on a unit contingent basis (if the output is not available because the plant is not operating, there is no requirement to provide output from other sources), back to the sellers at an average price of nearly $35 per megawatt-hour for approximately 10 years under power purchase agreements.

We describe the net assets acquired in *Note 14*.

Bethlehem Steel

On October 15, 2001, Bethlehem Steel Corporation filed for reorganization under Chapter 11 of the U.S. Bankruptcy Code. Bethlehem Steel's Sparrows Point plant, located in Baltimore, Maryland is BGE's largest customer, accounting for approximately three percent of electric revenues and one percent of gas revenues. At December 31, 2002 and 2001, our exposure to Bethlehem Steel was not material. There is uncertainty regarding the continuation of Bethlehem Steel's operations; however, we do not expect the impact to be material to our financial results.

Strategy

We are pursuing an integrated energy platform that provides a balanced mix of stable and predictable earnings from regulated utility operations with a growth platform from merchant energy operations. The strategy for our merchant energy business is to be a leading competitive provider of energy solutions for large customers in North America. Our merchant energy business has electric generation assets located in various regions of the United States and has an origination and risk management operation that focuses on providing energy solutions to meet customers' needs throughout North America.

The integration of electric generation assets with origination and risk management of energy and energy-related commodities allows our merchant energy business to manage energy price risk over geographic regions and over time. Our focus is on providing solutions to customers' energy needs, and our origination and risk management operation adds value to our 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 origination and risk management operation by providing a source of reliable power supply that provides a physical hedge for some of our load-serving activities.

To achieve our strategic objectives, we expect to continue to pursue opportunities that expand our access to customers and to support our origination and risk management operation with generation assets that have diversified geographic, fuel, and dispatch characteristics. We also expect to use a disciplined growth strategy through originating transactions with large customers and by acquiring and developing additional generating facilities when desirable to support our merchant energy business.

Our merchant energy business will focus on long-term, high-value sales of energy, capacity, and related products to large customers, including distribution utilities, industrial customers, and large commercial customers primarily in the regional markets in which end-use customer electricity rates have been deregulated and thereby separated from the cost of generation supply. These markets include the New England region, the New York region, the Mid-Atlantic region, Texas, Illinois, California, and certain areas in Canada.

The growth of BGE and our other retail energy services businesses is expected through focused and disciplined expansion primarily from new customers.

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 business environment and regulatory changes, and to maintain a strong balance sheet and investment-grade credit quality.

Beginning in the fourth quarter of 2001, we undertook a number of initiatives to reduce our costs towards competitive levels and to ensure that our resources are focused on our core energy businesses. This included the implementation of workforce reduction programs, termination of all planned development projects not under construction, and the acceleration of our exit strategy for certain non-core assets.

We also might consider one or more of the following strategies:

- the complete or partial separation of BGE's transmission function from its distribution function,
- mergers or acquisitions of utility or non-utility businesses or assets, and
- sale of assets or one or more businesses.

Business Environment

General Industry

The utility industry and energy markets continue to experience significant changes as a result of less liquid and more volatile wholesale markets, deteriorating credit qualities of various industry participants, volatile power and fuel prices, excess generation in the domestic markets, and the slow recovery of the U.S. economy.

Due to market conditions in 2001, we canceled our separation plans and terminated our power business services agreement with Goldman Sachs on October 26, 2001 and decided to maintain our existing corporate structure. We also terminated all planned development projects not under construction. Separately, we initiated efforts to reduce costs in order to become more competitive and to sell certain non-core assets to focus attention and capital resources on our core energy businesses.

During 2002, the energy markets were affected by significant events, including expanded investigations by state and federal authorities into business practices of energy companies in the deregulated power and gas markets relating to "wash trading" to inflate revenues and volumes, and other trading practices allegedly designed to manipulate market prices. In addition, several merchant energy businesses significantly reduced their energy trading activities due to deteriorating credit quality.

Beginning in the second quarter of 2002, several regional energy markets experienced a significant decline in liquidity. As a result of the reduced market liquidity, our origination and risk management operation held energy positions in certain markets longer than it otherwise would have during the first half of 2002. In response to this reduced market liquidity, we reduced these positions and continue to modify our positions to reflect the underlying liquidity of the various regional energy markets.

As discussed above, certain companies in the energy industry have been experiencing deteriorating credit quality. We continue to actively manage our credit portfolio to attempt to reduce the impact of a potential counterparty default. We discuss our counterparty credit risk in more detail in the *Market Risk* section.

We also continue to examine plans to achieve our strategies and to further strengthen our balance sheet and enhance our liquidity. We discuss our strategies in the *Strategy* section. We discuss our liquidity in the *Financial Condition* section.

Electric Competition

We are facing competition in the sale of electricity in wholesale power markets and to retail customers.

Maryland

As a result of the deregulation of electric generation in Maryland, the following occurred effective July 1, 2000:

- All customers can choose their electric energy supplier. BGE provides fixed price standard offer service over various time periods for different classes of customers that do not select an alternative supplier until June 30, 2006.
- While BGE does not sell electric commodity to all customers in its service territory, BGE does deliver electricity to all customers and provides meter reading, billing, emergency response, regular maintenance, and balancing services.
- BGE provides a market rate standard offer service for those commercial and industrial customers who are no longer eligible for fixed price standard offer service until June 30, 2006.

BGE reduced residential base rates by approximately 6.5% on average, or about $54 million a year, from rates prior to July 1, 2000. These rates will not change before July 2006. While total residential base rates remain unchanged over this transition period (July 1, 2000 through June 30, 2006), the increase in the standard offer service rate is offset by a corresponding decrease in the competitive transition charge (CTC) that BGE receives from its customers.

Commercial and industrial customers have several service options that will fix electric energy rates through June 30, 2004 and transition charges through June 30, 2006.

BGE transferred, at book value, its nuclear generating assets, its nuclear decommissioning trust fund, and related assets and liabilities to Calvert Cliffs Nuclear Power Plant, Inc. In addition, BGE transferred, at book value, its fossil generating assets and related assets and liabilities and its partial ownership interest in two coal plants and a hydroelectric plant located in Pennsylvania to Constellation Power Source Generation.

Our origination and risk management operation provides BGE with 100% of the energy and capacity required to meet its standard offer service obligations through June 30, 2003. Our origination and risk management operation obtains the energy and capacity to supply BGE's standard offer service obligations from affiliates that own Calvert Cliffs and BGE's former fossil plants, supplemented with energy and capacity purchased from the wholesale market, as necessary.

In August 2001, BGE entered into contracts with our origination and risk management operation to supply 90% and Allegheny Energy Supply Company, LLC (Allegheny) to supply the remaining 10% of BGE's standard offer service for the final three years (July 1, 2003 to June 30, 2006) of the transition period. Currently, the credit ratings of Allegheny are below investment grade. Under the terms of the contract, in certain circumstances, BGE has the right to request additional credit support from Allegheny to secure performance under the contract. If BGE was to exercise these rights and Allegheny did not meet such request, BGE could liquidate and terminate the contract. As of the date of this report, Allegheny is in compliance with the terms of the contract.

BGE's (and other Maryland utilities') role in providing electricity supply to customers is currently the subject of a proceeding at the Maryland PSC. Specifically, BGE entered into a proposed settlement agreement with parties representing customers, industry, utilities, suppliers, the Maryland Energy Administration, the Maryland PSC's Staff, and the Office of People's Counsel that extends BGE's obligation to supply standard offer service.

Under the proposed settlement agreement, BGE would be obligated to provide market-based standard offer service to residential customers until June 30, 2010, and for commercial and industrial customers for a one, two or four year period beyond June 30, 2004, depending on customer size. The rates charged during this time would be fixed during the term of the supply contract and would include an administrative fee. The proposed settlement agreement currently is before the Maryland PSC for approval.

Other States

Several states, other than Maryland, have supported deregulation of the electric industry. The pace of deregulation in other states varies based on historical moves to competition and responses to recent market events. Certain states that were considering deregulation have slowed their plans or postponed consideration. In response to regional market differences and to promote competitive markets, the FERC proposed initiatives promoting the formation of Regional Transmission Organizations and a standard market design. If approved, these market changes could provide additional opportunities for our merchant energy business. We discuss these initiatives in the *FERC Regulation Regional Transmission Organizations and Standard Market Design* section.

As a result of ongoing litigation before the FERC regarding sales into the spot markets of the California Independent System Operator and Power Exchange, we estimate that we may be required to pay refunds of between $3 and $4 million for transactions that we entered into with these entities for the period between October 2000 and June 2001. However, our estimate is based on current information and because litigation is ongoing, new events could occur that could cause the actual amount, if any, to be materially different from our estimate.

Gas Competition

Currently, no regulation exists for the wholesale price of natural gas as a commodity, and the regulation of interstate transmission at the federal level has been reduced. All BGE gas customers have the option to purchase gas from other suppliers.

Regulation by the Maryland PSC

In addition to electric restructuring which was discussed earlier, regulation by the Maryland PSC influences BGE's businesses. The Maryland PSC determines the rates that BGE can charge customers for the electric distribution and gas businesses. The Maryland PSC incorporates into BGE's electric rates the transmission rates determined by FERC. Prior to July 1, 2000, BGE's regulated electric rates consisted primarily of a "base rate" and a "fuel rate." BGE unbundled its electric rates to show separate components for delivery service, competitive transition charges, standard offer services (generation), transmission, universal service, and taxes. The rates for BGE's regulated gas business continue to consist of a "base rate" and a "fuel rate."

Base Rate

The base rate is the rate the Maryland PSC allows BGE to charge its customers for the cost of providing them service, plus a profit. BGE has both an electric base rate and a gas base rate. 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 increased utility plant asset costs and higher operating costs, plus a profit, beginning at the time of replacement. Generally, rate increases improve our utility earnings because they allow us to collect more revenue. However, rate increases are normally granted based on historical data, and those increases may not always keep pace with increasing costs. Other parties may petition the Maryland PSC to decrease base rates.

On June 19, 2000, the Maryland PSC authorized a $6.4 million annual increase in our gas base rates effective June 22, 2000.

As a result of the deregulation of electric generation in Maryland, BGE's residential electric base rates are frozen until 2006. Electric delivery service rates are frozen until 2004 for commercial and industrial customers. The generation and transmission components of rates are frozen for different time periods depending on the service options selected by those customers.

Fuel Rate

Through June 30, 2000, we charged our electric customers separately for the fuel we used to generate electricity (nuclear fuel, coal, gas, or oil) and for the net cost of purchases and sales of electricity. We charged the actual cost of these items to the customer with no profit to us. If these fuel costs increased, the Maryland PSC generally permitted us to increase the fuel rate.

Under deregulation of electric generation, BGE's electric fuel rate was frozen until July 1, 2000, at which time the fuel rate clause was discontinued. We deferred the difference between our actual costs of fuel and energy and what we collected from customers under the fuel rate through June 30, 2000.

In September 2000, the Maryland PSC approved the collection of the $54.6 million accumulated difference between our actual costs of fuel and energy and the amounts collected from customers that were deferred under the electric fuel rate clause through June 30, 2000. We collected this accumulated difference from customers over the twelve-month period ended October 2001. Effective July 1, 2000, earnings are affected by the changes in the cost of fuel and energy.

We charge our gas customers separately for the natural gas they purchase from us. The price we charge for the natural gas is based on a market-based rates incentive mechanism approved by the Maryland PSC. We discuss market-based rates and a current proceeding with the Maryland PSC in more detail in the *Gas Cost Adjustments* section and in *Note 1*.

FERC Regulation

Regional Transmission Organizations and Standard Market Design

In December 1999, FERC issued Order 2000, amending its regulations under the Federal Power Act to advance the formation of Regional Transmission Organizations (RTOs) that would allow easier access to transmission.

On July 31, 2002, the FERC issued a proposed rulemaking regarding implementation of a standard market design (SMD) for wholesale electric markets. The SMD rulemaking is intended to complement the FERC's RTO order, and will require RTOs to substantially comply with its provisions. The SMD proposal requires transmission providers to turn over the operation of their facilities to an independent operator that will operate them consistent with a revised market structure proposed by the FERC. According to the FERC, the revised market structure will reduce inefficiencies caused by inconsistent market rules and barriers to transmission access. The FERC proposed that its rule be implemented in stages by October 1, 2004. Comments on the SMD proposal were submitted in February 2003. However, in early 2003, the FERC announced that it would issue a report on SMD and again solicit comments from interested parties.

In 1997, BGE turned over the operation of its transmission facilities to PJM, a FERC approved RTO, which generally conducts its operations in accordance with FERC standard market design principles. We believe that the SMD proposal may lead to long-term benefits for Constellation Energy and BGE because the proposal will promote competition in regions where it is implemented. However, until the proposal is finalized, we cannot predict its effect on our, or BGE's, financial results.

Cash Management

In August 2002, the FERC issued proposed rules for the regulation of cash management practices of a regulated subsidiary of a nonregulated parent. As currently proposed, we do not believe the proposed rule will have a material effect on our, and BGE's, financial results. We discuss our cash management arrangement in *Note 15*.

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 and fuels, and changes in energy supply and demand may impact the price of these energy commodities in both the spot market and the forward market. Typically, demand for electricity and its price are higher in the summer and the winter, when weather is more extreme. Similarly, 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.

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. Residential sales for our regulated businesses are impacted more by weather than commercial and industrial sales, which are mostly affected by business needs for electricity and gas.

However, the Maryland PSC allows us 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 *Weather Normalization* section.

We measure the weather's effect using "degree-days." The measure of degree-days for a given day is the difference between the average daily actual temperature and a baseline temperature of 65 degrees. Cooling degree-days result when the average daily actual temperature exceeds the 65 degree baseline. Heating degree-days result when the average daily actual temperature is less than the baseline.

During the cooling season, hotter weather is measured by more cooling degree-days and results in greater demand for electricity to operate cooling systems. During the heating season, colder weather is measured by more heating degree-days and results in greater demand for electricity and gas to operate heating systems.

We show the number of cooling and heating degree-days in 2002 and 2001, the percentage change in the number of degree-days from the prior year, and the number of degree-days in a "normal" year as represented by the 30-year average in the following table.

	2002	2001	30-year Average
Cooling degree-days	**1,006**	787	836
	27.8%	6.9%	

	2002	2001	30-year Average
Percentage change from prior year			
Heating degree-days	**4,542**	4,514	4,736
Percentage change from prior year	**0.6%**	(8.5)%	

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 availability and reliability within and between regions,
- procedures used to maintain the integrity of the physical electricity system during extreme conditions, and
- changes in the nature and extent of federal and state regulations.

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.

Other factors, aside from weather, 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 downtrend, our customers tend to consume less electricity and gas.

Environmental and Legal Matters

You will find details of our environmental matters in *Note 11* and *Item 1. Business Environmental Matters* section. You will find details of our legal matters in *Note 11*. Some of the 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*.

Results of Operations

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

Overview

Net Income

	2002	2001	2000
		(In millions)	
Net Income Before Special Items Included in Operations:			
Merchant energy	**$ 275.5**	$ 291.2	$ 213.6
Regulated electric	**119.8**	84.5	106.5
Regulated gas	**31.9**	38.3	30.6
Other nonregulated	**(13.1)**	(26.8)	(33.4)
Net Income Before Special Items Included in Operations	**414.1**	387.2	317.3
Special Items Included in Operations:			
Net gain on sales of investments and other assets	**166.7**	1.9	47.2
Workforce reduction costs	**(38.0)**	(64.1)	(4.2)
Impairments of investment in qualifying facilities and domestic power projects	**(9.9)**	(30.5)	
Costs associated with exit of BGE Home merchandise stores	**(6.1)**		
Impairments of real estate, senior-living, and international investments	**(1.2)**	(69.7)	
Contract termination related costs		(139.6)	
Reduction of financial investment		(2.8)	
Deregulation transition cost			(15.0)
Net Income Before Cumulative Effect of Change in Accounting Principle	**525.6**	82.4	345.3
Cumulative Effect of Change in Accounting Principle		8.5	
Net Income	**$ 525.6**	$ 90.9	$ 345.3

Net income for the periods presented reflect a significant shift from the regulated electric business to the merchant energy business as a result of the transfer of BGE's electric generation assets to nonregulated subsidiaries on July 1, 2000.

2002

Our total net income for 2002 increased $434.7 million, or $2.63 per share, compared to 2001 mostly because of the following:

- We recognized a $163.3 million after-tax gain, or $1.00 per share, on the sale of our investment in Orion as previously discussed in the *Significant Events* section.
- We recorded special items in 2001 that had a negative impact in that year.
- We had cost reductions due to productivity initiatives associated with our corporate-wide workforce reduction and other productivity programs.
- The addition of Nine Mile Point Nuclear Station (Nine Mile Point) to the generation fleet increased net income.
- We benefited from the absence of Goldman Sachs fees due to the termination of the power business services agreement in October 2001.
- We had higher mark-to-market earnings from our origination and risk management operation.
- We had higher earnings from our regulated electric business because of warmer summer weather in the central Maryland region.
- We had higher earnings from the addition of NewEnergy.
- We had higher earnings from our other nonregulated businesses due to the growth of our energy services business and improved results from our international portfolio.

These increases were partially offset by special items recorded in 2002 as previously discussed in the *Significant Events* section and the following:

- We had higher fixed charges due to the issuance of $2.5 billion of long-term debt that was primarily used to repay short-term borrowings and due to lower capitalized interest because of the new generating facilities that commenced operations since mid-2001.
- Our merchant energy business had higher purchased fuel costs.
- We had lower earnings due to the extended outage at Calvert Cliffs to replace the steam generators at Unit 1.
- Our merchant energy business had lower earnings due to the impact of large commercial and industrial customers leaving BGE's standard offer service and electing other generation suppliers resulting in the sale of excess generation at lower wholesale market prices.
- Our merchant energy business had lower earnings from our investments in qualifying facilities and domestic power projects.

In addition, our other nonregulated businesses recorded the following in 2001 that had a positive impact in that period:

- an $8.5 million after-tax, or $.05 per share, gain for the cumulative effect of adopting SFAS No. 133, and
- gains on the sale of securities of $30.0 million after-tax, or $.19 per share.

Earnings per share contributions from all of our business segments are impacted by the dilution resulting from the issuance of 13.2 million of common shares during 2001.

2001

Our total net income for 2001 decreased $254.4 million, or $1.73 per share, compared to 2000 mostly because the special items included in operations as previously discussed in the *Significant Events* section more than offset the $69.9 million, or $.29 per share, increase in our net income before special items.

Net income before special items was $387.2 million, or $2.41 per share, in 2001 compared to $317.3 million, or $2.12 per share, in 2000. Net income before special items was higher compared to 2000 mostly because BGE recorded $75.0 million pre-tax, or approximately $.30 per share, of amortization expense for the reduction of our generating plants associated with the deregulation of electric generation in 2000 that had a negative impact in that year. In addition, we had higher earnings from our regulated gas business in 2001 mostly because of increases in

the sharing mechanism under our gas cost adjustment clauses and the increase in our base rates. These increases were offset by the impact of a 6.5% annual electric residential rate reduction that was effective July 1, 2000.

The decrease in total net income for 2001 compared to 2000 also was partially offset by the following:

Our merchant energy business recorded in 2000 an expense of $15.0 million after-tax, or $.10 per share, for a deregulation transition cost to Goldman Sachs that had a negative impact in that year.

BGE recorded an expense of $4.2 million after-tax, or $.03 per share, for its employees that elected to participate in a targeted VSERP in 2000 that had a negative impact in that year.

We recorded an $8.5 million after-tax, or $.05 per share, gain for the cumulative effect of adopting SFAS No. 133 in the first quarter of 2001.

In the following sections, we discuss our net income by business segment in greater detail.

Merchant Energy Business

Background

Our merchant energy business is a competitive provider of energy solutions for large customers in North America. As discussed in the *Business Environment Electric Competition* section, in connection with the July 1, 2000 implementation of customer choice in Maryland, BGE's generating assets became part of our nonregulated merchant energy business, and our origination and risk management operation began selling to BGE the energy and capacity required to meet its standard offer service obligations for the first three years (July 1, 2000 to June 30, 2003) of the transition period.

In August 2001, BGE entered into a contract with our origination and risk management operation to provide 90% of the energy and capacity required for BGE to meet its standard offer service requirements for the final three years (July 1, 2003 to June 30, 2006) of the transition period. Also effective July 1, 2000, merchant energy business revenues include 90% of the competitive transition charges (CTC revenues) BGE collects from its customers and the portion of BGE's revenues providing for nuclear decommissioning costs.

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 policies as follows:

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

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 on a net basis in the period in which the change occurs. EITF 02-3 will affect how we apply the mark-to-market method of accounting. We discuss EITF 02-3 in the *Critical Accounting Policies* section and in *Note 1*.

Mark-to-market accounting requires us to make estimates and assumptions using judgment in determining the fair value of our contracts and in recording revenues from those contracts. We discuss the effects of mark-to-market accounting on our revenues in the *Competitive Supply Mark-to-Market Revenues* 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*.

As a result of the changes in our organization and senior management in late 2001, including the cancellation of our business separation and the termination of the power business services agreement with Goldman Sachs, we re-evaluated our load-serving activities in Texas and New England as discussed in more detail in the *Competitive Supply* section. We determined that since we manage these activities as a physical delivery business rather than a trading business, it is appropriate to apply accrual accounting for these activities. After the re-designation of existing contracts to non-trading, we began to record revenues and expenses on a gross basis, but this did not have a material impact on earnings because the resulting increase in revenues was accompanied by a similar increase in fuel and purchased energy expenses.

As a result of applying accrual accounting to an increasing portion of our merchant energy business, including the January 1, 2003 implementation of EITF 02-3, future mark-to-market earnings will be lower than they otherwise would have been because we will record the margin on new transactions as power is delivered to customers over the contract term using accrual accounting rather than in full at the inception of each new contract. However, we expect accrual earnings for 2003 to be $52 million higher than they would have been prior to applying EITF 02-3, reflecting the 2003 portion of the fair value of contracts converted to accrual accounting using market prices as of December 31, 2002.

While we cannot predict the ongoing impact of applying EITF 02-3, the timing of recognizing earnings on new transactions will change. In general, earnings on new transactions will no longer be recognized at the inception of the transactions under mark-to-market accounting because they will be recognized over the term of the transaction. However, we cannot predict the total impact of these changes on our earnings for the reasons discussed in the *Critical Accounting Policies* section.

Additionally, we also expect lower earnings volatility for this portion of our business because unrealized changes in the fair value of load-serving contracts will no longer be recorded as revenue at the time of the change under mark-to-market accounting as is required for trading activities. Any contracts subject to EITF 02-3 must be accounted for on the accrual basis and recorded gross rather than net upon application of EITF 02-3, which was effective after October 25, 2002 for new non-derivative transactions (including spot market purchases and sales) and January 1, 2003 for contracts existing as of October 25, 2002.

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Our merchant energy business results were as follows:

Net Income

	2002	2001	2000
		(In millions)	
Revenues	**$ 2,765.7**	$ 1,765.5	$ 1,025.7
Fuel and purchased energy expenses	**1,151.3**	484.5	199.5
Operations and maintenance expenses	**787.4**	597.8	387.3
Workforce reduction costs	**26.5**	46.0	
Impairment losses and other costs	**14.4**	46.9	
Contract termination related costs		224.8	
Depreciation and amortization	**242.8**	174.9	83.6
	83.5	49.4	24.6

	2002	2001	2000
Taxes other than income taxes			
Net loss on sales of assets	**3.7**		
Income from Operations	**$ 456.1**	$ 141.2	$ 330.7
Net Income	**$ 247.2**	$ 93.1	$ 198.6
Net Income Before Special Items Included in Operations	**$ 275.5**	$ 291.2	$ 213.6
Workforce reduction costs	**(16.0)**	(28.0)	
Impairment of investments in qualifying facilities and domestic power projects	**(9.9)**	(30.5)	
Net loss on sales of assets	**(2.4)**		
Contract termination related costs		(139.6)	
Deregulation transition cost			(15.0)
Net Income	**$ 247.2**	$ 93.1	$ 198.6

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 origination and risk management operation manages our costs of procuring fuel and energy and revenues we realize from the sale of energy to our customers. The difference between revenues and fuel and purchased energy expenses is the primary driver of 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 the relationship between revenues and fuel and purchased energy expenses. We discuss non-fuel direct costs, such as ancillary services, transmission costs, financing, and legal costs in conjunction with other operations and maintenance expenses later in this section.

We analyze our merchant energy revenues and fuel and purchased energy expenses in the following categories because of differences in the revenue sources, the nature of fuel and purchased energy expenses, and the risk profile of each category.

PJM Platform our fossil, nuclear, and hydroelectric generating facilities and load-serving activities in the PJM Interconnection (PJM) region for which the output is primarily used to serve BGE.

Plants with Power Purchase Agreements our generating facilities with long-term power purchase agreements, including our Nine Mile Point nuclear generating facility and our new Oleander and University Park generating facilities.

Competitive Supply our wholesale business that provides load-serving activities to distribution utilities (primarily in Texas and New England), other wholesale origination and risk management services, and electric and gas retail energy services to large commercial and industrial customers.

Other our other gas-fired generating facilities, investments in qualifying facilities and domestic power projects, and our generation and consulting services.

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

	2002		2001		2000	
	(Dollar amounts in millions)					
Revenues:						
PJM Platform	**$ 1,391.4**		$ 1,379.2		$ 731.7	
Plants with Power Purchase Agreements	**456.4**		70.8			
Competitive Supply	**825.7**		175.8		151.5	
Other	**92.2**		139.7		142.5	
Total	**$ 2,765.7**		$ 1,765.5		$ 1,025.7	
Fuel and purchased energy expenses:						
PJM Platform	**$ 527.5**		$ 420.9		$ 199.5	
Plants with Power Purchase Agreements	**40.0**		13.9			
Competitive Supply	**552.9**					
Other	**30.9**		49.7			
Total	**$ 1,151.3**		$ 484.5		$ 199.5	
Revenue less fuel and purchased energy expenses:		**% of Total**		**% of Total**		**% of Total**
PJM Platform	**$ 863.9**	**53%**	$ 958.3	75%	$ 532.2	65%
Plants with Power Purchase Agreements	**416.4**	**26**	56.9	4		
Competitive Supply	**272.8**	**17**	175.8	14	151.5	18
Other	**61.3**	**4**	90.0	7	142.5	17
Total	**$ 1,614.4**	**100%**	$ 1,281.0	100%	$ 826.2	100%

PJM Platform

	2002	2001	2000
	(In millions)		
Revenues	**$ 1,391.4**	$ 1,379.2	$ 731.7

	2002	2001	2000
Fuel and purchased energy expenses	**527.5**	420.9	199.5
Revenues less fuel and purchased energy	**$ 863.9**	$ 958.3	$ 532.2

Revenues

BGE Standard Offer Service

The majority of PJM Platform revenues arise from BGE standard offer service. Revenues from BGE's standard offer service requirements decreased $8.3 million, including CTC and decommissioning revenues that decreased $4.3 million, in 2002 compared to 2001.

These decreases were due to approximately 1,200 megawatts of large commercial and industrial customers leaving BGE's standard offer service in the second quarter of 2002 and electing other electric generation suppliers, partially offset by higher volumes sold to BGE due to warmer summer weather. However, approximately one-third of the load for large commercial and industrial customers left BGE's standard offer service and elected BGE Home, a subsidiary of Constellation Energy, as their electric generation supplier. Our merchant energy business continues to provide the energy to BGE Home to meet the requirements of these customers under market-based rates. Revenues from BGE Home were $45.3 million in 2002. BGE Home is included in our other nonregulated businesses.

CTC revenues are impacted by the CTC rates our merchant energy business receives from BGE customers as well as the volumes delivered to BGE customers. The CTC rates decline over the transition period as previously discussed in the *Electric Competition Maryland* section.

Revenues from BGE's standard offer service requirements increased $578.0 million, including CTC and decommissioning revenues that increased $74.4 million, in 2001 compared to 2000 because our merchant energy business provided BGE's standard offer service requirements for a full year in 2001 as compared to six months in 2000.

Other PJM Revenues

Other merchant energy revenues in the PJM region decreased $32.6 million in 2002 compared to 2001 mostly because of the following:

- The sales of power from our owned generation in excess of that required to serve BGE's standard offer service requirements decreased $17.9 million compared to 2001. These sales decreased primarily due to lower generation because of the extended outage at Calvert Cliffs in order to replace the steam generators at Unit 1 and lower generation from our coal plants partially offset by higher revenues due to warmer summer weather.
- Our merchant energy business recognized a $9.5 million gain on the sale of a project under development in this region in 2001 that had a positive impact in that year.

Other merchant energy revenues in the PJM region increased $69.5 million in 2001 compared to 2000 mostly because of the following:

- The sales of power from our Baltimore plants in excess of that required to serve BGE's standard offer service requirements increased $51.2 million.
- Our merchant energy business recognized a $9.5 million gain on the sale of a project under development in the PJM region in March 2001.
- The Handsome Lake generating facility that commenced operations in 2001 provided revenues of $8.8 million.

Fuel and Purchased Energy Expenses

Our merchant energy business had higher fuel and purchased energy expenses in the PJM region in 2002 compared to 2001 primarily due to higher replacement power costs from the extended outage at Calvert Cliffs and higher coal prices. These were partially offset by lower generation at our coal plants.

Our merchant energy business began an extended outage at Unit 1 of Calvert Cliffs during the first quarter of 2002 to replace the unit's steam generators, which was completed at the end of June 2002. As a result, our merchant energy business had lower revenues and higher operating costs, including higher purchased energy to meet BGE's standard offer service. Calvert Cliffs will replace the steam generators for Unit 2 during the 2003 refueling outage. Based on our current outage schedule, we expect the 2003 outage to be shorter than the 2002 extended outage. However, this outage will be significantly longer than a normal refueling outage. We expect lower annual revenues and higher annual operating costs in 2003 from Calvert Cliffs compared to 2001 due to the longer outage.

Our merchant energy business had higher fuel and purchased energy expenses in the PJM region in 2001 compared to 2000 mostly because 2001 reflects a full year's operation of the generation plants that were transferred from BGE effective July 1, 2000. The fuel cost increase also reflects higher fuel prices for generating electricity mostly because coal prices increased during 2001 compared to 2000.

Plants with Power Purchase Agreements

	2002	**2001**	**2000**
		(In millions)	
Revenues	**$ 456.4**	$ 70.8	$
Fuel and purchased energy expenses	**40.0**	13.9	
Revenues less fuel and purchased energy	**$ 416.4**	$ 56.9	$

The increases in revenues and expenses primarily were due to a full year's results from Nine Mile Point, which we acquired in November 2001, and the University Park generating facility, which commenced operations in the second half of 2001. In addition, the Oleander generating facility commenced operations in the second half of 2002.

Competitive Supply

	2002	**2001**	**2000**
		(In millions)	
Accrual revenues	**$ 587.6**	$	$
Mark-to-market revenues	**238.1**	175.8	151.5
Fuel and purchased energy expenses	**552.9**		
Revenues less fuel and purchased energy	**$ 272.8**	$ 175.8	$ 151.5

We analyze our accrual and mark-to-market competitive supply activities separately below.

Accrual Revenues and Fuel and Purchased Energy Expenses

Our accrual revenues and fuel and purchased energy expenses increased in 2002 primarily due to the re-designation of our Texas and New England load-serving activities to accrual and the acquisition of NewEnergy in September 2002. Texas and New England revenues were $310.5 million, and purchased energy expenses were $317.1 million. NewEnergy's revenues were $261.3 million, and purchased energy expenses were $211.6 million. We discuss the re-designation of Texas and New England below.

Since February 2002, we manage our Texas load-serving activities as a physical delivery business separate from our trading activities and re-designated these activities as non-trading. We believe this designation more accurately reflects the substance of our Texas load-serving physical delivery activities.

At the time of this change in designation, we reclassified the fair value of load-serving contracts and physically delivering power purchase agreements in Texas from "Mark-to-market energy assets and liabilities" to "Other assets and liabilities." The contracts reclassified consisted of gross assets of $78 million and gross liabilities of $15 million, or a net asset of $63 million. EITF 02-3 required us to remove the unamortized balance of these assets and liabilities, excluding the costs of any acquired contracts, from our Consolidated Balance Sheets by January 1, 2003.

After the change in designation, the results of our Texas load-serving business are included in "Nonregulated revenues" on a gross basis as power is delivered to our customers and "Operating expenses" as costs are incurred. Prior to the re-designation, the results of these activities were reported on a net basis as part of mark-to-market revenues included in "Nonregulated revenues." Mark-to-market revenues for the Texas trading activities were a net loss of $1.2 million for the portion of 2002 prior to designation as non-trading. Mark-to-market revenues for the Texas trading activities were a net loss of $33.4 million in 2001.

Since future power sales revenues and costs from this business will be reflected in our Consolidated Statements of Income as part of "Nonregulated revenues" when power is delivered and "Operating expenses" when the costs are incurred, this re-designation generally will delay the recognition of earnings from this business in the future compared to what we would have recognized under mark-to-market accounting. The change in designation of our Texas load-serving business did not impact our cash flows.

In addition, our New England load-serving business consists primarily of contracts to serve the full energy and capacity requirements of retail customers and electric distribution utilities and associated power purchase agreements to supply our customers' requirements. We manage this business primarily to assure profitable delivery of customers' energy requirements rather than as a traditional trading activity. Therefore, we use accrual accounting for New England load-serving transactions and associated power purchase agreements entered into since the second quarter of 2002.

Because applicable accounting rules significantly limited the circumstances under which contracts previously designated as a trading activity could be re-designated as non-trading, prior to EITF 02-3, we were required to continue to include contracts entered into before the second quarter of 2002 in our mark-to-market accounting portfolio. However, under EITF 02-3, on January 1, 2003, we removed these contracts from our "Mark-to-market energy assets and liabilities" and began to account for these contracts under the accrual method of accounting.

We discuss the implications of EITF 02-3 in more detail in the *Critical Accounting Policies* section and in *Note 1*.

Mark-to-Market Revenues

Mark-to-market revenues include net gains and losses from origination 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*. We also discuss the implications of EITF 02-3 on the mark-to-market method of accounting 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 revenues and earnings will fluctuate. We cannot predict these fluctuations, but the impact on our revenues and 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 revenues and earnings are:

- the number, size, and profitability of new transactions,
- changes in the level and volatility of forward commodity prices and interest rates,
- changes in estimates of customers' load requirements as a result of changes in weather and customer attrition due to the selection of other suppliers, and
- the number and size of our open derivative positions.

Mark-to-market revenues were as follows:

	2002	2001	2000

	2002	2001	2000
		(In millions)	
Unrealized revenues			
Origination transactions	**$ 160.4**	$ 227.0	$ 158.8
Risk management			
Unrealized changes in fair value	**66.9**	(55.7)	(4.0)
Changes in valuation techniques	**10.8**	4.5	(3.3)
Reclassification of settled contracts to realized	**(45.4)**	(19.7)	57.0
Total risk management	**32.3**	(70.9)	49.7
Total unrealized revenues	**192.7**	156.1	208.5
Realized revenues	**45.4**	19.7	(57.0)
Total mark-to-market revenues	**$ 238.1**	$ 175.8	$ 151.5

Revenues from origination transactions represent the initial unrealized fair value of new wholesale energy transactions (including restructurings) at the time of contract execution to the extent permitted by applicable accounting rules. Risk management revenues represent both realized and unrealized gains and losses from changes in the value of our entire portfolio. We discuss the changes in mark-to-market revenues below. We show the relationship between our revenues and the change in our net mark-to-market energy asset later in this section.

Our mark-to-market revenues were and continue to be affected by a decrease in the portion of our activities that is subject to mark-to-market accounting. As previously discussed, we re- designated our Texas load-serving business as accrual during 2002, and we began to account for new non-derivative origination transactions on the accrual basis rather than under mark-to-market accounting. Under EITF 02-3, we no longer record existing non-derivative contracts at fair value beginning January 1, 2003. Further, effective July 1, 2002, to the extent that we are not able to observe quoted market prices or other current market transactions for contract values determined using models, we record a reserve to adjust such contracts to result in zero gain or loss at inception. We remove the reserve and record such contracts at fair value when we obtain current market information for contracts with similar terms and counterparties.

Mark-to-market revenues increased $62.3 million during 2002 compared to 2001 mostly because of net gains from risk management activities compared to net losses in the prior year, partially offset by lower revenues from origination transactions. The increase in risk management revenues is primarily due to the absence of mark-to-market losses recorded in 2001 on Texas trading activities designated as non-trading in 2002, favorable changes in regional power prices, price volatility, and other factors in 2002 compared to 2001. The decrease in origination revenues reflects the use of accrual accounting for new load-serving transactions originated beginning in the second quarter of 2002, the impact of applying the EITF guidance on recording gains at the time of contract origination as previously described, and fewer individually significant transactions in 2002 as compared to 2001.

Mark-to-market revenues increased $24.3 million during 2001 compared to 2000 mostly because of higher revenues from new origination transactions, partially offset by net losses from risk management activities. The increase in origination revenues reflects new full-requirements load-serving transaction volumes, primarily in New England and Texas. The increase in risk management net losses is primarily due to decreases in both future power prices and price volatility in 2001 and costs of establishing hedges for new origination transactions. The decrease in forward prices and volatility negatively affected the mark-to-market value of our portfolio of supply arrangements. However, these mark-to-market losses were more than offset by mark-to-market gains in the form of new origination transactions that were in part enabled by these supply arrangements.

Mark-to-Market Energy Assets and Liabilities

Our mark-to-market energy assets and liabilities are comprised of a combination of derivative and non-derivative (physical) contracts. The non-derivative assets and liabilities primarily relate to load-serving activities originated prior to the shift to accrual accounting earlier this year.

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 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,

	2002	**2001**
	(In millions)	
Current Assets	**$ 144.0**	$ 398.4
Noncurrent Assets	**1,348.2**	1,819.8
Total Assets	**1,492.2**	2,218.2
Current Liabilities	**94.1**	323.3
Noncurrent Liabilities	**881.5**	1,476.5
Total Liabilities	**975.6**	1,799.8
Net mark-to-market energy asset	**$ 516.6**	$ 418.4

At December 31, 2002, the primary components of our net mark-to-market energy asset were as follows:

	(In millions)
Non-derivative contracts reversed as part of cumulative effect of a change in accounting principle effective January 1, 2003	$ 374.9
Derivatives designated as hedges effective January 1, 2003	(6.1)
Derivatives designated as normal purchases and sales effective January 1, 2003	64.3
Other positions	83.5
Total	$ 516.6

The non-derivative portion of the net asset represents the fair value of contracts that we reclassified to accrual effective January 1, 2003 as required by EITF 02-3. Derivatives designated as hedges effective January 1, 2003 represent derivative contracts used to hedge our physical delivery contracts in connection with the implementation of EITF 02-3. Derivatives designated as normal purchases and sales effective January 1, 2003, represent derivative contracts used to economically hedge our physical delivery contracts in connection with the implementation of EITF 02-3 but which receive accrual accounting treatment. The remainder of the net asset primarily consists of a PJM generation hedge comprised of a group of options that serve as an economic hedge of the PJM generation portfolio. These options give us the right to sell power at a floor price which is valuable to our generation operation when market prices are low and also give us the right to buy power at a capped price, which adds value when the market prices are high. We have not designated these options as hedges under SFAS No. 133 due to the complexity of qualifying options as effective hedges under the requirements of that standard.

The following are the primary sources of the change in net mark-to-market energy asset during 2002 and 2001:

	2002	**2001**
	(In millions)	
Fair value beginning of year	**$ 418.4**	$ 527.9

	2002		2001	
Changes in fair value recorded as revenues				
Origination transactions	**$ 160.4**		$ 227.0	
Unrealized changes in fair value	**66.9**		(55.7)	
Changes in valuation techniques	**10.8**		4.5	
Reclassification of settled contracts to realized	**(45.4)**		(19.7)	
Total changes in fair value recorded as revenues		**192.7**		156.1
Changes in fair value recorded as operating expenses		**9.0**		(15.0)
Changes in value of exchange-listed futures and options		**(8.5)**		6.9
Net change in premiums on options		**(40.1)**		(242.2)
Texas contracts re-designated as non-trading		**(63.3)**		
Other changes in fair value		**8.4**		(15.3)
Fair value at end of year		**$ 516.6**		$ 418.4

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

Origination transactions represent the initial unrealized fair value at the time these contracts are executed.

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 revenue:

Changes in fair value recorded as operating expenses represent accruals for future incremental expenses in connection with servicing origination transactions. While these accruals are recorded as part of the fair value of the net mark-to-market energy asset, they are reflected in our Consolidated Statements of Income as expenses rather than revenues.

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.

We discuss our Texas contracts re-designated as non-trading in more detail in the *Competitive Supply* section.

The settlement terms of the net mark-to-market energy asset and sources of fair value as of December 31, 2002 are as follows:

	Settlement Term							Fair Value
	2003	**2004**	**2005**	**2006**	**2007**	**2008**	**Thereafter**	
				(In millions)				
Prices provided by external sources (1)	$ 50.1	$ (23.9)	$ (65.1)	$ (0.5)	$ (1.1)	$ (3.5)	$ 10.5	$ (33.5)
Prices based on models	(0.2)	124.4	113.8	83.9	72.2	77.7	78.3	550.1
Total net mark-to-market energy asset	$ 49.9	$ 100.5	$ 48.7	$ 83.4	$ 71.1	$ 74.2	$ 88.8	$ 516.6

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

The implementation of EITF 02-3 significantly impacted the amount and composition of the net mark-to-market energy asset. The table below presents the settlement terms of our net mark-to-market energy asset as of January 1, 2003 after reflecting the impact of implementing EITF 02-3. We discuss EITF 02-3 and the effect of its implementation in more detail in the *Critical Accounting Policies* section and in *Note 1*.

	Settlement Term After Reflecting Implementation of EITF 02-3							Fair Value
	2003	**2004**	**2005**	**2006**	**2007**	**2008**	**Thereafter**	
				(In millions)				
Prices provided by external sources (1)	$ 9.7	$ (2.4)	$ (48.7)	$ (1.0)	$ (3.0)	$ (5.2)	$ 3.9	$ (46.7)
Prices based on models	0.8	1.1	35.3	24.5	23.0	20.0	25.5	130.2
Total net mark-to-market energy asset	$ 10.5	$ (1.3)	$ (13.4)	$ 23.5	$ 20.0	$ 14.8	$ 29.4	$ 83.5

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 tables 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 hours for delivery terms primarily through 2004, but up to 2010, depending upon the region,
- forward purchases and sales of electricity during off-peak hours for delivery terms primarily through 2004, but up to 2007, depending upon the region,
- options for the purchase and sale of electricity during peak hours for delivery terms through 2003, depending upon the region,
- forward purchases and sales of electric capacity for delivery terms through 2005,
- forward purchases and sales of natural gas, coal and oil for delivery terms through 2005, and
- options for the purchase and sale of natural gas, coal and oil for delivery terms through 2005.

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,
- estimated volumes for customer requirements, which are influenced by customer switching behavior, impact of temperature on electric prices, and customer acquisition and servicing costs,
- estimated volumes for tolling contracts, 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 origination 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 tables 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 tables 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 tables. However, based upon the nature of the origination 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 tables represent expected future cash flows based on the level of forward prices and volatility factors as of December 31, 2002 and could change significantly as a result of future changes in these factors. Additionally, because the depth and liquidity of the power markets varies substantially between regions and time periods, the prices used to determine fair value could be affected significantly by the volume of transactions executed.

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.

Other

	2002	**2001**	**2000**
		(In millions)	
Revenues	**$ 92.2**	$ 139.7	$ 142.5
Fuel and purchased energy expenses	**30.9**	49.7	
Revenues less fuel and purchased energy	**$ 61.3**	$ 90.0	$ 142.5

We analyze the revenues and fuel and purchased energy expenses of the final category of our merchant energy business below.

Revenues

Our other merchant energy business revenues decreased in 2002 compared to 2001 mostly because we had lower revenues of $23.4 million from our mid-continent region facilities that commenced operations in mid-summer of 2001 primarily due to lower output from these facilities because of a less favorable relationship between energy prices and gas costs. In addition, we had lower revenues of $14.0 million from our investments in qualifying facilities and domestic power projects. We discuss our investments in qualifying facilities and domestic power projects in more detail on the next page.

Our other merchant energy business revenues decreased in 2001 compared to 2000 mostly because of the following:

- Our merchant energy business had lower revenues of $27.1 million from our investments in qualifying facilities and domestic power projects.
- Our merchant energy business terminated an operating arrangement and sold certain subsidiaries of Constellation Operating Services Inc. (COSI) to Orion in 2000. COSI ended its exclusive arrangement with Orion to operate Orion's facilities, and Orion purchased from COSI the four subsidiary companies formed to operate power plants owned by Orion. Our merchant energy business recognized a $13.3 million gain on this sale in 2000 which had a positive impact on that year, and the absence of $25.6 million of revenues during 2001 compared to 2000 due to the sale of these subsidiaries.

These lower revenues were partially offset by higher revenues of $59.2 million from our mid-continent region gas-fired peaking facilities that commenced operations in mid-summer of 2001.

Investments in Qualifying Facilities and Domestic Power Projects

Our merchant energy business holds up to a 50% ownership interest in 28 operating domestic energy projects that consist of electric generation, fuel processing, or fuel handling facilities. Of these 28 projects, 20 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. Earnings from our investments were $9.1 million in 2002, $23.1 million in 2001, and $50.2 million in 2000.

The decrease in revenues in 2002 compared to 2001 was due to a geothermal project generating at a lower capacity and lower revenues from our California projects as discussed below. The decrease in revenues in 2001 compared to 2000 was primarily due to lower revenues from our California projects.

California Power Purchase Agreements

Our merchant energy business has $260.6 million invested in partnerships that own 13 operating power projects of which our ownership percentage represents 137 megawatts of electricity that are sold to Pacific Gas & Electric (PGE) and to Southern California Edison (SCE) in California under power purchase agreements. Our merchant energy business was not paid in full for its sales from these plants to the two utilities from November 2000 through early April 2001. At December 31, 2001, our portion of the amount due for unpaid power sales from these utilities was approximately $45 million. We recorded reserves of approximately 20% of this amount in 2001.

Through the date of this report, we received the $45 million for unpaid power sales plus interest. We reversed all of our credit reserves that totaled $9.1 million during the first quarter of 2002 as payments ensued following court-approved restructuring agreements.

Revenues from these projects, net of credit reserves, were $20.0 million in 2002, $22.1 million in 2001, and $44.1 million in 2000. While California power prices were significantly lower during 2002 compared to 2001, 2001 results were reduced by credit reserves established for our exposure in California. These reserves were subsequently reversed in 2002 as discussed above, which had a positive impact in 2002.

Revenues decreased in 2001 compared to 2000 because of lower power prices in California during the second half of 2001. While energy rates were higher during the first half of 2001, the higher rates were offset by reserves established for our exposure in California during that year.

The projects entered into agreements with PGE through July 2006 and SCE through April 2007 that provide for fixed-price payments averaging $53.70 per megawatt-hour plus the stated capacity payments in the original agreements.

Fuel and Purchased Energy Expenses

Our other merchant energy business fuel and purchased energy expenses decreased in 2002 compared to 2001 mostly because we had lower fuel and purchased energy for our mid-continent region facilities primarily due to lower demand for the output of these facilities.

Operations and Maintenance Expenses

Our merchant energy business operations and maintenance expenses increased $189.6 million in 2002 compared to 2001 mostly due to the following:

- Higher operations and maintenance expenses of $224.0 million associated with the acquisitions of Nine Mile Point in November 2001 and NewEnergy in September 2002.
- Higher operations and maintenance expenses of $11.6 million associated with new generating facilities that commenced operations beginning in mid-2001 and mid-2002.

These increases were partially offset by the following:

- Lower costs of approximately $31 million due to productivity initiatives associated with our corporate-wide workforce reduction and other productivity programs.
- Lower origination and risk management operating expenses of $10.2 million as a result of the absence of Goldman Sachs fees due to the termination of the power business services agreement in October 2001. The Goldman Sachs fees were $28.9 million in 2001. This decrease was partially offset by an increase in expenses associated with the growth of the operation.

Our merchant energy business operations and maintenance expenses increased $210.5 million in 2001 compared to 2000 mostly due to the following:

Higher operations and maintenance expenses of $203.0 million mostly because 2001 reflects a full year's operation of the generation plants that were transferred from BGE effective July 1, 2000.

Higher operations and maintenance expenses of $29.5 million associated with the acquisitions of Nine Mile Point in November 2001.

Higher operations and maintenance expenses of $4.3 million associated with new generating facilities that commenced operations beginning in mid-2001.

Higher origination and risk management operating expenses of $41.2 million as a result of the growth of the operation and higher direct expenses primarily due to higher transaction volumes.

These increases were partially offset by the following:

The decrease in the Goldman Sachs fees of $52.4 million due to the termination of the power business services agreement in October 2001. The Goldman Sachs fee was $81.3 million in 2000, which included the $24.0 million, or $.10 per share, deregulation transition cost.

Lower operations and maintenance expenses at COSI of $20.9 million due to the sale of certain subsidiaries as previously discussed.

Workforce Reduction Costs, Impairment Losses and Other Costs, Contract Termination Related Costs, and Net Loss on Sales of Assets

Our merchant energy business recognized the following in 2002:

$26.5 million of expenses associated with our workforce reduction efforts,

$14.4 million of impairment losses for the decline in value of certain investments in partnerships that have investments in qualifying facilities and domestic power projects,

$6.0 million loss on the sale of a steam turbine generator set, and

$2.3 million gain on the sale of Cabazon, a wind-powered independent power project located in California.

Our merchant energy business recognized the following in 2001:

$224.8 million of expenses related to the termination of the power business services agreement with Goldman Sachs,

$46.0 million of expenses associated with our workforce reduction efforts,

$40.8 million of impairment losses of certain planned development projects that were terminated, and

$6.1 million loss on the impairment of a power project.

We discuss these special items in more detail in the *Significant Events* section and in *Note 2*.

As a result of our workforce reduction programs and other process improvement initiatives, our merchant energy business expects to realize cost savings of approximately $44 million partially offset by other increases in operating costs in 2003.

Depreciation and Amortization Expense

Merchant energy depreciation and amortization expense increased $67.9 million in 2002 compared to 2001 mostly because of the depreciation and amortization associated with Nine Mile Point and the new generating facilities.

Merchant energy depreciation and amortization expense increased $91.3 million in 2001 compared to 2000 mostly because 2001 includes a full year of expenses associated with the generation plants that were transferred from BGE effective July 1, 2000. Additionally, 2001 expenses include depreciation and amortization associated with the new generating facilities and Nine Mile Point.

Taxes Other Than Income Taxes

Merchant energy taxes other than income taxes increased $34.1 million in 2002 compared to 2001 mostly because of taxes other than income taxes associated with Nine Mile Point and the new generating facilities.

Merchant energy taxes other than income taxes increased $24.8 million in 2001 compared to 2000 mostly because of taxes other than income taxes associated with the generation plants that were transferred from BGE effective July 1, 2000. Additionally, 2001 expenses include taxes other than income taxes associated with Nine Mile Point and the new generating facilities.

Regulated Electric Business

As previously discussed, our regulated electric business was significantly impacted by the July 1, 2000 implementation of customer choice. These changes include BGE's generating assets and related liabilities becoming part of our nonregulated merchant energy business on that date.

Effective July 1, 2000, BGE unbundled its rates to show separate components for delivery service, transition charges, standard offer services (generation), transmission, universal service, and taxes. BGE's rates also were frozen in total except for the implementation of a residential base rate reduction totaling approximately $54 million annually. In addition, 90% of the CTC revenues BGE collects and the portion of its revenues providing for decommissioning costs, are included in revenues of the merchant energy business.

As part of the deregulation of electric generation, while total rates were frozen over the transition period, the increasing rates received from customers under the standard offer service are offset by declining CTC rates.

Net Income

	2002	**2001**	**2000**
		(In millions)	
Revenues	**$ 1,966.0**	$ 2,040.0	$ 2,135.2
Fuel and purchased energy expenses	**1,080.7**	1,192.8	870.7
Operations and maintenance expenses	**252.4**	258.7	447.2
Workforce reduction costs	**34.0**	55.7	7.0
Depreciation and amortization	**174.2**	173.3	319.9
Taxes other than income taxes	**137.0**	139.5	157.8
Income from Operations	**$ 287.7**	$ 220.0	$ 332.6
Net Income	**$ 99.3**	$ 50.9	$ 102.3
Net Income Before Special Items Included in Operations	**$ 119.8**	$ 84.5	$ 106.5
Workforce reduction costs	**(20.5)**	(33.6)	(4.2)
Net Income	**$ 99.3**	$ 50.9	$ 102.3

	2002	2001	2000

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 in 2002 compared to 2001 mostly because of the following:

- increased distribution sales volumes due to warmer summer weather, increased usage per customer, and an increased number of customers,
- cost reductions resulting from our corporate-wide workforce reduction programs and other productivity initiatives, and
- lower interest expense.

Net income from the regulated electric business decreased in 2001 compared to 2000 mostly because of the July 1, 2000 deregulation of electric generation as discussed later in this section.

Electric Revenues

The changes in electric revenues in 2002 and 2001 compared to the respective prior year were caused by:

	2002	2001
	(In millions)	
Distribution sales volumes	**$ 32.7**	$ 2.8
Standard offer service	**(70.2)**	(79.3)
Fuel rate surcharge	**(43.2)**	30.5
Total change in electric revenues from electric system sales	**(80.7)**	(46.0)
Interchange and other sales		(53.8)
Other	**6.7**	4.6
Total change in electric revenues	**$ (74.0)**	$ (95.2)

Distribution Sales Volumes

"Distribution sales volumes" are sales to customers in BGE's service territory at rates set by the Maryland PSC.

The percentage changes in our electric system sales volumes, by type of customer, in 2002 and 2001 compared to the respective prior year were:

	2002	2001
Residential	**8.0%**	0.3%
Commercial	**3.2**	0.7
Industrial	**0.7**	(0.7)

In 2002, we distributed more electricity to residential and commercial customers compared to 2001 due to warmer summer weather, increased usage per customer, and an increased number of customers. We distributed about the same amount of electricity to industrial customers in 2002 compared to 2001.

In 2001, we distributed about the same amount of electricity to all customer classes compared to 2000 due primarily to milder winter weather offset by an increased number of customers.

Standard Offer Service

BGE provides standard offer service for customers that do not select an alternative generation supplier as previously discussed. Standard offer service revenues decreased in 2002 compared to 2001 primarily as a result of large commercial and industrial customers leaving BGE's standard offer service and electing other electric generation suppliers. These decreased revenues were partially offset by increased sales to residential customers due to warmer summer weather and an increase in the standard offer service rate that BGE charges its customers.

As a result of large commercial and industrial customers leaving BGE's service, BGE also had lower purchased energy expense as discussed in the *Electric Fuel and Purchased Energy Expenses* section.

Standard offer service revenues decreased in 2001 compared to 2000 mostly due to:

- the 6.5% annual residential rate reduction of $17.6 million recorded through June 30, 2001, and
- $74.4 million of higher CTC and decommissioning revenues that were transferred to the merchant energy business effective July 1, 2000.

These decreases were partially offset by the increase in the standard offer service rate that BGE charges its customers and other net impacts of the rate restructuring previously discussed.

Fuel Rate Surcharge

Prior to July 1, 2000, we deferred (included as an asset or liability in our Consolidated Balance Sheets and excluded from our Consolidated Statements of Income) the difference between our actual costs of fuel and energy and what we collected from customers under the fuel rate in a given period. Effective July 1, 2000, the fuel rate clause was discontinued as a result of the deregulation of electric generation. In September 2000, the Maryland PSC approved the collection of the $54.6 million accumulated difference between our actual costs of fuel and energy and the amounts collected from customers that were deferred under the electric fuel rate clause through June 30, 2000. We collected this accumulated difference from customers over the twelve-month period ended October 2001.

Interchange and Other Sales

"Interchange and other sales" are sales in the PJM energy market and to others. PJM is a FERC approved RTO that also operates a regional power pool with members that include many wholesale market participants, as well as BGE and other utility companies. Prior to the implementation of customer choice, BGE sold energy to

PJM members and to others after it had satisfied the demand for electricity in its own system.

Effective July 1, 2000, BGE no longer engages in interchange sales, as these activities are included in our merchant energy business, which resulted in a decrease in interchange and other sales for 2001 compared to 2000.

Electric Fuel and Purchased Energy Expenses

	2002	2001	2000
		(In millions)	
Actual costs	**$ 1,080.7**	$ 1,150.5	$ 868.0
Recovery of costs deferred under electric fuel rate clause		42.3	2.7
Total electric fuel and purchased energy expenses	**$ 1,080.7**	$ 1,192.8	$ 870.7

Actual Costs

As discussed in the *Business Environment Electric Competition* section, effective July 1, 2000, BGE transferred its generating assets to, and began purchasing substantially all of the energy and capacity required to provide electricity to standard offer service customers from, the merchant energy business.

Our actual costs of fuel and purchased energy decreased in 2002 compared to 2001 mostly because BGE purchased less energy due to large commercial and industrial customers leaving BGE's fixed price standard offer service and electing other electric generation suppliers.

Our actual costs of fuel and purchased energy increased in 2001 compared to 2000 mostly because of the deregulation of electric generation. The higher amount BGE paid for purchased energy from our merchant energy business is offset by the absence of $206.4 million in 2001 in fuel costs, and lower operations and maintenance, depreciation, taxes, and other costs at BGE as a result of no longer owning and operating the transferred electric generation plants.

Prior to July 1, 2000, BGE's purchased fuel and energy costs only included actual costs of fuel to generate electricity (nuclear fuel, coal, gas, or oil) and electricity we bought from others.

Electric Operations and Maintenance Expenses

Regulated electric operations and maintenance expenses decreased $6.3 million in 2002 compared to 2001 mostly due to cost reductions resulting from our corporate-wide workforce reduction programs and other productivity initiatives.

Regulated electric operations and maintenance expenses decreased $188.5 million during 2001 compared to 2000 mostly because effective July 1, 2000, costs of $194.7 million were no longer incurred by this business segment. These costs were associated with the electric generation assets that were transferred to the merchant energy business.

Workforce Reduction Costs

BGE's electric business recognized expenses associated with our workforce reduction efforts as previously discussed in the *Significant Events* section and in *Note 2*.

As a result of our workforce reduction programs and other process improvement initiatives, our electric business expects to realize cost savings of approximately $17 million partially offset by other increases in operating costs in 2003.

Electric Depreciation and Amortization Expense

Regulated electric depreciation and amortization expense was about the same during 2002 compared to 2001. Regulated electric depreciation and amortization expense decreased $146.6 million during 2001 compared to 2000 mostly due to:

- the absence of $75.0 million of amortization expense recorded in 2000 associated with the $150 million reduction of our generating plants as a result of the deregulation of electric generation, and
- $75.1 million of expenses associated with the transfer of the generation assets to the merchant energy business effective July 1, 2000.

Electric Taxes Other Than Income Taxes

Regulated electric taxes other than income taxes were about the same during 2002 compared to 2001. Regulated electric taxes other than income taxes decreased $18.3 million during 2001 compared to 2000 mostly due to the absence of taxes other than income taxes associated with the generation assets that were transferred to the merchant energy business effective July 1, 2000 partially offset by fewer tax credits.

Regulated Gas Business

All BGE customers have the option to purchase gas from other suppliers. To date, customer choice has not had a material effect on our, or BGE's, financial results.

Net Income

	2002	2001	2000
		(In millions)	
Revenues	**$ 581.3**	$ 680.7	$ 611.6
Gas purchased for resale expenses	**316.7**	401.3	350.6
Operations and maintenance expenses	**102.9**	104.3	100.6
Workforce reduction costs	**1.3**	1.3	
Depreciation and amortization	**47.4**	47.7	46.2
Taxes other than income taxes	**34.4**	34.3	34.8
Income from Operations	**$ 78.6**	$ 91.8	$ 79.4
Net Income	**$ 31.1**	$ 37.5	$ 30.6
Net Income Before Special Items Included in Operations	**$ 31.9**	$ 38.3	$ 30.6
Workforce reduction costs	**(0.8)**	(0.8)	
Net Income	**$ 31.1**	$ 37.5	$ 30.6

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 decreased during 2002 compared to 2001 mostly due to a $7.7 million pre-tax disallowed portion of a previously established regulatory asset as discussed in the *Gas Cost Adjustments* section and a $3.7 million pre-tax decrease in the shareholders' portion of the sharing mechanism under our gas cost adjustment clauses.

Net income from our regulated gas business increased during 2001 compared to 2000 mostly due to a $3.6 million pre-tax increase in the shareholders' portion of the sharing mechanism under our gas cost adjustment clauses and an increase in our base rates.

Gas Revenues

The changes in gas revenues in 2002 and 2001 compared to the respective prior year were caused by:

	2002	2001
	(In millions)	
Distribution sales volumes	**$ 1.4**	$ (3.4)
Base rates	**(2.9)**	3.3
Weather normalization	**(0.5)**	11.9
Gas cost adjustments	**(55.8)**	43.6
Total change in gas revenues from gas system sales	**(57.8)**	55.4
Off-system sales	**(38.8)**	12.6
Other	**(2.8)**	1.1
Total change in gas revenues	**$ (99.4)**	$ 69.1

<u>*Distribution Sales Volumes*</u>

The percentage changes in our distribution sales volumes, by type of customer, in 2002 and 2001 compared to the respective prior year were:

	2002	2001
Residential	**3.5%**	(7.8)%
Commercial	**7.1**	3.5
Industrial	**(1.4)**	(25.2)

We distributed more gas to residential and commercial customers during 2002 compared to 2001 mostly due to increased usage per customer, slightly colder weather, and an increased number of customers. We distributed less gas to industrial customers mostly because of a decreased number of customers.

We distributed less gas to residential customers during 2001 compared to 2000 mostly due to milder winter weather and lower usage per customer partially offset by an increased number of customers. We distributed more gas to commercial customers mostly due to higher usage per customer. We distributed less gas to industrial customers mostly because of lower usage due to customers switching to lower cost alternative fuel sources and lower business needs related to the general downturn in the economy, partially offset by an increased number of customers.

Base Rates

Base rate revenues decreased during 2002 compared to 2001 mostly because of a decrease in the rate approved by the Maryland PSC associated with the energy conservation surcharge program.

Base rate revenues increased during 2001 compared to 2000 mostly because the Maryland PSC authorized a $6.4 million annual increase in our base rates effective June 22, 2000.

Weather Normalization

The Maryland PSC allows us to record a monthly adjustment to our gas revenues to eliminate the effect of abnormal weather patterns on our gas system sales volumes. This means our monthly gas 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 market-based rates, 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. The shareholders' portion decreased $3.7 million during 2002 compared to 2001. The shareholders' portion increased $3.6 million during 2001 compared to 2000.

Effective November 2001, the Maryland PSC approved an order 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. We do not expect these changes to have a material impact on our financial results.

Delivery service customers are not subject to the gas cost adjustment clauses because we are not selling gas to them. We charge these customers fees to recover the fixed costs for the transportation service we provide. These fees are the same as the base rate charged for gas distributed and are included in gas distribution volumes.

Gas cost adjustment revenues decreased during 2002 compared to 2001 mostly because the gas we sold to non-delivery service customers was at a lower price, partially offset by more gas sold. Gas cost adjustment revenues increased during 2001 compared to 2000 mostly because the gas we sold to non-delivery service customers was at a higher price, partially offset by less gas sold. In the first half of 2001, the revenue increase reflects the significant increase in natural gas prices.

In December 2002, a Hearing Examiner from the Maryland PSC issued a proposed order related to our annual gas adjustment clause review proceeding that will allow us to recover $1.7 million of a previously established regulatory asset of $9.4 million for certain credits that were over-refunded to customers through our market-based rates. BGE reserved the remaining difference of $7.7 million as disallowed fuel costs.

However, we appealed the proposed order. As of the date of this report, the Maryland PSC has not acted on BGE's appeal.

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 we have satisfied our customers' demand, are not subject to gas cost adjustments. The Maryland PSC approved an arrangement for part of the margin from off-system sales to benefit customers (through reduced costs) and the remainder to be retained by BGE (which benefits shareholders).

Revenues from off-system gas sales decreased during 2002 compared to 2001 mostly because we sold less gas at a lower price.

Revenues from off-system gas sales increased during 2001 compared to 2000 mostly because the gas we sold off-system was at a higher price partially offset by less gas sold. In the first half of 2001, the revenue increase reflects the significant increase in natural gas prices.

Gas Purchased For Resale Expenses

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

Gas costs decreased during 2002 as compared to 2001 because we purchased gas at a lower price partially offset by the $7.7 million of disallowed fuel costs as previously discussed in the *Gas Cost Adjustments* section.

Gas costs increased during 2001 compared to 2000 mostly because gas we purchased was at a higher price partially offset by less gas purchased for both system and off-system sales.

Gas Operations and Maintenance Expenses

Regulated gas operations and maintenance expenses were about the same during 2002 and 2001 compared to the respective prior year. In 2002, cost reductions resulting from our corporate-wide workforce reduction programs and other productivity initiatives were offset by the amortization of gas regulatory assets established in 2001 related to these initiatives.

Workforce Reduction Costs

BGE's gas business recognized expenses associated with our workforce reduction efforts as previously discussed in the *Significant Events* section and in *Note 2*.

As a result of our workforce reduction programs and other process improvement initiatives, our gas business expects to realize cost savings of approximately $4 million partially offset by other increases in operating costs in 2003.

Other Nonregulated Businesses

Net Income

	2002	2001	2000
		(In millions)	
Revenues	**$ 537.4**	$ 552.6	$ 635.2
Operating expenses	**505.9**	510.7	588.8
Workforce reduction costs	**1.0**	2.7	
Impairment losses and other costs	**10.8**	111.9	
Depreciation and amortization	**16.6**	23.2	20.3
Taxes other than income taxes	**4.3**	3.4	4.3
Net gain on sales of investments and other assets	**265.0**	6.2	78.1

	2002	2001	2000
Income (Loss) from Operations	**$ 263.8**	$ (93.1)	$ 99.9
Net Income (Loss) Before Cumulative Effect of Change in Accounting Principle	**$ 148.0**	$ (99.1)	$ 13.8
Cumulative Effect of Change in Accounting Principle		8.5	
Net Income (Loss)	**$ 148.0**	$ (90.6)	$ 13.8
Net Loss Before Special Items Included in Operations	**$ (13.1)**	$ (26.8)	$ (33.4)
Net gain on sales of investments and other assets	**169.1**	1.9	47.2
Workforce reduction costs	**(0.7)**	(1.7)	
Costs associated with exit of BGE Home merchandise stores	**(6.1)**		
Impairment of real estate, senior-living, and international investments	**(1.2)**	(69.7)	
Reduction of financial investment		(2.8)	
Net Income (Loss) Before Cumulative Effect of Change in Accounting Principle	**148.0**	(99.1)	13.8
Cumulative Effect of Change in Accounting Principle		8.5	
Net Income (Loss)	**$ 148.0**	$ (90.6)	$ 13.8

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

Net income from our other nonregulated businesses increased during 2002 compared to 2001 mostly because of the following:

We recognized a $255.5 million pre-tax gain on the sale of our investment in Orion in 2002.

We recorded impairment losses and other costs in 2001 that had a negative impact in that year.

We recognized a loss on the sale of our Guatemalan operations in 2001 that had a negative impact in that year.

We had higher earnings due to the growth of our energy services business and improved results from our international portfolio.

These increases were partially offset by the following:

We recognized gains on the sale of securities in 2001 that had a positive impact in that year, including the $14.9 million pre-tax gain on the sale of one million shares of our Orion investment and $34.6 million pre-tax gains on the sale of securities by our financial investments operation.

We recorded $9.5 million of pre-tax costs associated with the exit of BGE Home merchandise stores in 2002.

We recorded impairment losses of $1.8 million pre-tax related to certain non-core assets in 2002.

Net income from our other nonregulated businesses decreased during 2001 compared to 2000 mostly because of the following items:

Our Latin American operation recorded a loss of $43.3 million pre-tax on the sale of our Guatemalan operations.

We recorded impairment losses of $107.3 million pre-tax related to certain non-core assets.

Our financial investments operation recorded a $4.6 million pre-tax reduction of its investment in an aircraft due to the decline in value of used airplanes as a result of the September 11, 2001 terrorist attacks and the general downturn in the aviation industry.

Our financial investments operation had lower earnings due to lower gains on the sale of securities and declining equity values in 2001 compared to 2000.

We discuss our special items further in the *Significant Events* section and in *Note 2*.

In addition, we recognized an $8.5 million after-tax, or $.05 per share, gain for the cumulative effect of adopting SFAS No. 133 in the first quarter of 2001.

As previously discussed in the *Significant Events* section, we decided to sell certain non-core assets and accelerate the exit strategies on other assets that we will continue to hold and own over the next several years. These assets included approximately 1,300 acres of land holdings in various stages of development located in seven sites in the central Maryland region, an operating waste water treatment plant located in Anne Arundel County, Maryland, all of our 18 senior-living facilities and certain international power projects. In 2002, we sold approximately 800 acres of land holdings, all of our senior-living facilities, and a South American generating facility. 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 additional losses.

Our remaining projects are partially or substantially developed. Our strategy is to hold and in some cases further develop these projects to increase their value. However, if we were to sell these projects in the current market, we may have losses that could be material, although the amount of the losses is hard to predict.

In addition, we initiated a liquidation program for our financial investments operation and expect to sell substantially all of our investments in this operation by the end of 2003. Through February 28, 2003, we liquidated approximately 85% of our investment portfolio since the beginning of 2002.

Consolidated Nonoperating Income and Expenses

Other Income

Other income increased $29.2 million during 2002 compared to 2001 mostly because of interest income on the nuclear decommissioning trust fund transferred in connection with the acquisition of Nine Mile Point and income on temporary cash investments. Other income was about the same in 2001 compared to 2000.

Other income for BGE increased $10.3 million during 2002 compared to 2001 mostly because of interest income on temporary cash investments in the Constellation Energy cash pool. Other income for BGE decreased $7.1 million during 2001 compared to 2000 mostly due to the absence of income on the Calvert Cliffs decommissioning trust fund that was transferred to our merchant energy business effective July 1, 2000 as a result of electric deregulation.

Fixed Charges

Total fixed charges increased $42.7 million during 2002 compared to 2001 mostly because of a higher level of debt outstanding at higher interest rates and lower capitalized interest due to our new generating facilities commencing operations. In 2002, we issued $2.5 billion of long-term debt and used the proceeds to repay short-term borrowings, to prepay the Nine Mile Point sellers' note, and to fund acquisitions. Total fixed charges decreased $32.6 million during 2001 compared to 2000 mostly because of lower interest rates and higher capitalized interest associated with our construction of new generating facilities. These decreases were offset partially by a higher average level of debt outstanding.

Total fixed charges for BGE decreased $14.0 million during 2002 as compared to 2001 mostly because of a lower level of debt outstanding due to the repayment of maturing long-term debt. Total fixed charges for BGE decreased $29.4 million during 2001 compared to 2000 mostly because of a lower level of debt outstanding primarily due to the transfer of debt to our merchant energy business effective July 1, 2000 due to the implementation of electric deregulation.

Income Taxes

The differences in income taxes result from a combination of the changes in income and the effective tax rate. We include an analysis of the changes in the effective tax rate in *Note 9*.

Financial Condition

Cash Flows

Cash provided by operations was $1,020.0 million in 2002 compared to $573.3 million in 2001 and $850.9 million in 2000.

Cash used in investing activities was $319.8 million in 2002 compared to $1,472.7 million in 2001 and $1,106.5 million in 2000. The decrease in 2002 compared to 2001 was mostly due to the sale of Orion and COPT that generated $555.4 million in cash proceeds, as well as the liquidation program associated with our investment portfolio and a decrease in capital spending due to the termination of all planned development projects. This was partially offset by the acquisitions of NewEnergy (net of cash acquired) for $204.8 million in September 2002 and of Alliance (net of cash acquired) for $16.6 million in December 2002. The increase in 2001 compared to 2000 was mostly due to increased purchases of property, plant and equipment and other capital expenditures including $382.7 million relating to the net cash paid for the acquisition of Nine Mile Point.

Cash used in financing activities was $157.6 million in 2002 compared to cash provided by financing activities of $789.1 million in 2001 and $345.6 million in 2000. The decrease in 2002 compared to 2001 was mostly due to higher repayment of debt in 2002 and the issuance of common stock in 2001. This was partially offset by higher issuance of debt during 2002. The increase in 2001 compared to 2000 was mostly due to increased proceeds from the issuance of common stock, an increase in proceeds from the net issuance of short-term borrowings, and a $130.0 million decrease in common stock dividends paid. These items were partially offset by the issuance of less long-term debt and higher repayments of our long-term debt.

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, and the amount of debt as a component of total capitalization. All Constellation Energy and BGE credit ratings have stable outlooks. 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 Originated Preferred Securities and Preference Stock	BBB	Baa1	A-

Available Sources of Funding

In 2001, we decided to sell certain non-core assets to focus on our core strategies. During 2002, we realized proceeds of over $800 million from the sale of non-core assets and used these funds to repay both short-term and long-term debt. In addition, during 2002, we issued $2.5 billion of debt and established $1.28 billion of credit facilities resulting in $1.7 billion of total credit facilities. We continuously monitor our liquidity requirements and believe that our 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 the $2.5 billion of debt issued in 2002, Constellation Energy has a commercial paper program under which we can issue short-term notes to fund our subsidiaries. At December 31, 2002, we had approximately $1.5 billion of credit under three facilities as discussed below.

In June 2002, Constellation Energy arranged a $640 million 364-day revolving credit facility and a $640 million three-year revolving credit facility. We use these two facilities to allow issuance of commercial paper and letters of credit along with our previously established $188.5 million revolving credit facility that expires in June 2003.

At December 31, 2002, we had $338.7 million of outstanding letters of credit that results in approximately $1.1 billion of unused credit facilities. These three facilities can issue letters of credit up to approximately $1.1 billion. Constellation Energy also has access to interim lines of credit as required from time to time to support its outstanding commercial paper.

BGE

BGE maintains $200.0 million in annual committed credit facilities, expiring May through November 2003, in order to allow commercial paper to be issued. As of December 31, 2002, BGE had no outstanding commercial paper, which results in $200.0 million in unused credit facilities. BGE also has access to interim lines of credit as required from time to time to support its outstanding commercial paper.

Other Nonregulated Businesses

BGE Home Products & Services maintains a program to sell up to $50 million of receivables.

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 business requires a great deal of capital. Our actual consolidated capital requirements for the years 2000 through 2002, along with the estimated annual amount for 2003, are shown in the table below.

We will continue to have cash requirements for:

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

Capital requirements for 2003 and 2004 include estimates of spending for existing and anticipated projects. We continuously review and modify those estimates. Actual requirements may vary from the estimates included in the table below because of a number of factors including:

- regulation, legislation, and competition, BGE load requirements,

environmental protection standards,

the type and number of projects selected for construction or acquisition,

the effect of market conditions on those projects,

the cost and availability of capital, and

the availability of cash from operations.

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

	2000	2001	2002	2003
		(In millions)		
Nonregulated Capital Requirements:				
Merchant energy (excludes acquisitions)				
Construction program	$ 537	$ 697	$ 122	$
Steam generators	21	53	83	70
Environmental controls	45	89	66	20
Continuing requirements (including nuclear fuel)	96(A)	205	370	320(B)
Total merchant energy capital requirements	699	1,044	641	410
Other nonregulated capital requirements	131	35	65	65
Total nonregulated capital requirements	830	1,079	706	475
Utility Capital Requirements:				
Regulated electric				
Generation	73			
Steam generators	13			
Environmental controls	17			
Transmission and distribution	187	180	167	205
Total regulated electric	290	180	167	205
Regulated gas	60	59	50	55
Total utility capital requirements	350	239	217	260
Total capital requirements	$ 1,180	$ 1,318	$ 923	$ 735

(A)
Effective July 1, 2000, includes $44.6 million for electric generation and nuclear fuel formerly part of BGE's regulated electric business.

(B)
Excludes capital requirements and financing costs for the High Desert Power Project, which are estimated to be approximately $90 million for the full year of 2003.

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

As of the date of this report, we have not completed our 2004 capital budgeting process, but expect our 2004 capital requirements to be approximately $600-700 million.

Capital Requirements

Merchant Energy Business

Our merchant energy business will invest in the following:

- Costs for replacing the steam generators at Calvert Cliffs. In March 2000, we received a license extension from the NRC that extends Calvert Cliffs' operating licenses to 2034 for Unit 1 and 2036 for Unit 2. Replacement of the steam generators will allow us to operate these units through our operating license periods. The 2002 steam generator replacement for Unit 1 was completed at the end of June 2002. We expect the 2003 steam generator replacement to occur during the 2003 refueling outage for Unit 2.

- Continuing requirements, including construction expenditures for improvements to generating plants, nuclear fuel costs, costs of complying with the Environmental Protection Agency (EPA), Maryland, and Pennsylvania nitrogen oxides (NOx) emissions regulations, and enhancements to our information technology infrastructure. We discuss the NOx regulations and timing of expenditures in *Note 11*.

The table on the previous page does not include the financing for the High Desert 830 megawatt gas-fired generation project in California, which is under an operating lease with a term through February 2006. Under the terms of the lease, we are required to make payments that represent all or a portion of the lease balance if construction is terminated prior to completion or we default under the lease.

Under certain circumstances, we may be required to either post cash collateral equal to the outstanding lease balance or we may elect to purchase the property for the outstanding lease balance. At any time during the term of the lease we have the right to pay off the lease and acquire the asset from the lessor. At December 31, 2002, the outstanding lease balance plus other committed expenses was approximately $585 million.

Our wholly owned subsidiary, High Desert Power Project LLC, is supervising the construction of, and leasing, the High Desert project from High Desert Power Trust, an independent special purpose entity (SPE) created to own and lease the project to our subsidiary. Neither Constellation Energy nor any affiliate owns any equity or other interest in High Desert Power Trust, which is owned by a consortium of banks and other financial institutions. We provide a guaranty of High Desert Power Project LLC's obligations to the Trust.

The High Desert Power Project uses an off-balance sheet financing structure through this SPE and currently qualifies as an operating lease. As an operating lease, we do not record any assets or debt associated with the project in our Consolidated Balance Sheets. In January 2003, the FASB issued Interpretation No. (FIN) 46, *Consolidation of Variable Interest Entities*, that will impact the accounting for, but not the cash flows associated with, our High Desert operating lease and the related SPE. Under the interpretation and current lease structure, we will be required to consolidate the SPE in our Consolidated Balance Sheets as of July 1, 2003, which is the effective date of FIN 46. Had we consolidated this project at December 31, 2002, we would have recorded approximately $488.7 million of development, construction, and capitalized financing costs as an asset and the related financial obligations as a liability in our Consolidated Balance Sheets. We discuss FIN 46 in more detail in *Note 1*.

The lease with the Trust contains several events of default that are commonly found in financings of this type, including failure to make all payments when due, failure to comply with all covenants, violation of material representations and warranties and change of control. In addition, several events of default are applicable to us as guarantor, including defaults in other material financing agreements and failure to own 100% of BGE's common stock.

At the conclusion of the lease term in 2006, we have the following options:

renew the lease upon approval of the lessors,

elect to purchase the property for a price equal to the lease balance at the end of the term, or

request the lessor to sell the property.

If the lessor sells the property, we guarantee the payment of any difference between the sale proceeds and the lease balance at the time of sale up to a maximum amount of approximately 83% of such lease balance. The lease balance at the end of the term is currently estimated to be $600 million, which represents the estimated cost of the project; however, this may vary based on the ultimate cost of construction and interest incurred during the construction period.

Regulated Electric and Gas

Regulated electric and gas construction expenditures primarily include new business construction needs and improvements to existing facilities.

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. Most of the projects recently constructed were funded through corporate borrowings by Constellation Energy. Many of the qualifying facilities and independent power projects that we have an interest 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.

BGE

Funding for utility capital expenditures is expected from internally generated funds. During 2003, we expect our regulated utility business to generate significant excess cash flows from operations. If necessary, additional funding may be obtained from commercial paper issuances, available capacity under credit facilities, the issuance of long-term debt, trust securities, or preference stock, and/or from time to time equity contributions from Constellation Energy. During 2002, Constellation Energy made a $200 million capital contribution to BGE. BGE also participates in a cash pool administered by Constellation Energy as discussed in *Note 15*.

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. BGE Home Products & Services can continue to fund capital requirements through sales of receivables.

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 Operation Other Nonregulated Businesses* section.

Committed Amounts

Our total contractual and contingent obligations as of December 31, 2002 are shown in the following table:

	Payments/Expiration				
	2003	2004-2005	2006-2007	Thereafter	Total
	(In millions)				
Contractual Obligations					
Short-term borrowings	$ 10.5	$	$	$	$ 10.5
Nonregulated long-term debt[1]	5.5	315.6	620.1	2,208.6	3,149.8
BGE long-term debt	284.2	194.7	591.4	829.7	1,900.0
BGE preference stock				190.0	190.0
Fuel and transportation	626.9	316.9	145.2	94.2	1,183.2
Purchased capacity and energy[2]	182.8	160.7	46.5	73.1	463.1
Operating leases	34.6	103.7	38.0	151.6	327.9
Capital and loan commitments [3]	32.7	0.5			33.2
Total contractual obligations	$ 1,177.2	$ 1,092.1	$ 1,441.2	$ 3,547.2	$ 7,257.7
Contingent Obligations					
Letters of credit	$ 338.3	$ 0.4	$	$	$ 338.7
Guarantees - competitive supply[4]	1,758.8	167.0	35.8	189.4	2,151.0
Other guarantees, net [5]	16.5	2.2	602.1	140.8	761.6
Total contingent obligations	$ 2,113.6	$ 169.6	$ 637.9	$ 330.2	$ 3,251.3
Total obligations	$ 3,290.8	$ 1,261.7	$ 2,079.1	$ 3,877.4	$ 10,509.0

1 *Amounts reflected in long-term debt maturities do not include $394.3 million investors may require us to repay early through put options and remarketing features.*

2 *Our contractual obligations for purchased capacity and energy are shown on a gross basis for certain transactions, including contracts in Texas that were re-designated and NewEnergy.*

3 *Amounts related to capital expenditures are included for applicable years in our capital requirements table.*

4 *While the face amount of these guarantees is $2,151.0 million, we do not expect to fund the full amount as our calculation of the fair value of obligations covered by these guarantees was $519.8 million at December 31, 2002.*

5 *Other guarantees in the above table are shown net of liabilities recorded at December 31, 2002 in our Consolidated Balance Sheets. The 2006 amount shown in the table primarily relates to the High Desert lease.*

While we included our contingent obligations in the table above, these amounts do not represent incremental consolidated Constellation Energy obligations; rather, they primarily represent guarantees from one Constellation entity to another. We do not expect to fund the full amounts under the letters of credit and guarantees. Specifically, the $2,151.0 million guarantees competitive supply represent the face amount of these guarantees. However, we do not expect to fund the full amount, as our calculation of the fair value of obligations covered by these guarantees was $519.8 million at December 31, 2002.

Lease payments under the High Desert operating lease are reflected in "Other guarantees, net" in the table on the previous page. The lease balance at the end of the 2006 lease term is currently estimated to be $600 million.

The table on the previous page does not include the fixed payment portions of our mark-to-market energy assets and liabilities primarily related to capacity payments under tolling contracts. We discuss the expected settlement terms of these contracts in the *Competitive Supply Mark-to-Market Energy Assets and Liabilities* section.

Liquidity Provisions

We have certain agreements that contain provisions that would require additional collateral upon significant 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. However, under counterparty contracts related to our origination and risk management operation, where we are obligated to post collateral, we estimate that we would have additional collateral obligations based on downgrades to the following credit ratings for our Senior Unsecured Debt:

Credit Ratings Downgraded	Level Below Current Rating	Incremental Obligations	Cumulative Obligations
		(In millions)	
BBB/Baa2	1	$ 55	$ 55
BBB-/Baa3	2	125	180
Below investment grade	3	500	680

At December 31, 2002, we had approximately $1.3 billion of unused credit facilities and $615.0 million of cash available to meet potential requirements. However, based on market conditions and contractual obligations at the time of such a downgrade, we could be required to post collateral in an amount that could exceed the amounts specified above, and which could be material.

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

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 violated, the lending institutions can decline making new advances or issuing 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, 2002, the debt to capitalization ratios as defined in the credit agreements were no greater than 57%.

A BGE credit facility of $50.0 million that expires in August 2003 requires BGE to maintain a ratio of debt to capitalization equal to or less than 70%. At December 31, 2002, the debt to capitalization ratio for BGE as defined in the credit agreement was 54%. At December 31, 2002, no amount is outstanding under this facility.

Failure by Constellation Energy, or BGE, to comply with these covenants could result in the maturity of the debt outstanding under these facilities being accelerated. 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 and Nine Mile Point to ensure these plants have funds to meet expenses and obligations to safely operate and maintain the plants.

We discuss our short-term borrowings in *Note 7*, long-term debt in *Note 8*, lease requirements in *Note 10*, and commitments and guarantees in *Note 11*.

Market Risk

We are exposed to various market risks, including changes in interest rates, certain commodity prices, credit risk, and equity prices. To manage our market risk, we may enter into various derivative instruments including swaps, forward contracts, futures contracts, and options. In this section, we discuss our current market risk and the related use of derivative instruments.

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. We may use derivative instruments to manage our interest rate risks. 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

	2003	2004	2005	2006	2007	Thereafter	Total	Fair value at Dec. 31, 2002
				(Dollar amounts in millions)				
Short-term debt								
Variable-rate debt	$ 10.5	$	$	$	$	$	$ 10.5	$ 10.5
Average interest rate	3.61%						3.61%	
Long-term debt								
Variable-rate debt	$ 5.0	$ 7.0	$ 7.5	$ 120.6	$ 10.0	$ 185.8	$ 335.9	$ 335.9
Average interest rate	5.49%	5.45%	5.50%	1.75%	5.50%	1.76%	2.08%	
Fixed-rate debt	$ 284.7(A)	$ 152.0	$ 343.8	$ 352.8	$ 728.1	$ 2,852.5	$ 4,713.9	$ 5,018.8
Average interest rate	6.50%	5.75%	7.72%	5.54%	7.00%	6.90%	6.74%	

(A)
Amount excludes $136.5 million of long-term debt that contains certain put options under which lenders could potentially require us to repay the debt prior to maturity and is classified as current portion of long-term debt in our Consolidated Balance Sheets.

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 standard offer service and our competitive supply activities, and our mark-to-market 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 operational 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. A number of factors associated with the structure and operation of the electricity 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 have not hedged the associated financial exposure, this 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,
- procedures used to maintain the integrity of the physical electricity system during extreme conditions, and
- changes in the nature and extent of federal and state regulations.

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.

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 either to generate power using plants with more costly fuel or 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 earnings.

Operational Risk

Operational 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. For 2003, we expect to use the majority of the generating capacity controlled by our merchant energy business to provide standard offer service to BGE or to serve the load requirements of the sellers of Nine Mile Point. Beginning in July 2002, approximately 1,200 megawatts of industrial customer load moved from BGE's standard offer service to market-based rates. Going forward, our merchant energy business will supply 100% of the standard offer service to BGE through June 30, 2003 and 90% from July 1, 2003 through June 30, 2006.

As a result of declines in BGE's standard offer service load and the 2,900 megawatts of natural gas-fired peaking and combined cycle generating facilities recently constructed, we have a substantial amount of generating capacity that is subject to future changes in wholesale electricity prices and 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 on 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 as changes in fuel costs.

Additionally, 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 sale commitments through the operation of other more costly generating facilities or through the purchase of energy in the wholesale market at higher prices.

Our nuclear plants produce electricity at a relatively low marginal cost. As a result, the costs of replacement energy associated with outages at these plants can be significant. If an unplanned outage were to occur during the summer or winter when demand was at a high level, the replacement power costs could have a material adverse impact on our financial results. Calvert Cliffs experienced an extended outage to replace the steam generators for Unit 1 during a refueling outage in the spring of 2002, and will experience another extended outage to replace the steam generators for Unit 2 during a refueling outage in the spring 2003.

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, 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 electricity and purchases of fuel and 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, and
- fixing the price for a portion of anticipated energy purchases to supply our load-serving customers.

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 monitor and manage our risk exposures through separate, but complementary financial, operational, and credit reporting systems. Constellation Energy's board of directors establishes parameters for the risks that we can undertake and risk levels are monitored daily by management and our Chief Risk Officer. In addition, we maintain segregation of duties, with credit review and risk monitoring functions performed by groups that are independent from revenue producing groups.

We measure the sensitivity of our 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 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 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 amount represents the potential pre-tax loss in the fair value of mark-to-market energy assets and liabilities over a one-day holding period. Based on the confidence levels in the table below, we would expect a one-day change in fair value greater than or equal to the daily value at risk at least once per year. Our value at risk was as follows:

	99.9% Confidence Level		**95% Confidence Level**	
Year Ended December 31,	**2002**	**2001**	**2002**	**2001**
	(In millions)			
Year end	**$ 7.4**	$ 18.0	**$ 3.0**	$ 7.4
Average	**15.5**	18.0	**6.4**	7.5
High	**33.8**	68.9	**13.9**	26.9
Low	**4.2**	8.7	**1.7**	3.6

The high value at risk amount for the year 2001 represents certain hedge contracts entered into in anticipation of closing an offsetting transaction. When the offsetting transaction closed within several days, the value at risk amount returned to a level more representative of the average for the year.

Due to the inherent limitations of statistical measures such as value at risk, the relative immaturity of the competitive market for electricity and related derivatives, 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

Effective July 1, 2000, BGE's residential rates are frozen for a six-year period, and its commercial and industrial rates are frozen for four to six years. BGE entered into standard offer service arrangements with our origination and risk management operation and Allegheny Energy Supply Company to provide the energy and capacity required to meet its standard offer service obligations through June 30, 2006.

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 1*. At December 31, 2002 and 2001, 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 a counterparty's nonperformance. We use credit policies to manage our credit risk, including utilizing an established credit approval process, monitoring 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, net of any unrealized losses, where we have a legally enforceable right of setoff.

Recently, several major participants in the energy markets suffered severe declines in their credit ratings or declared bankruptcy. However, as of December 31, 2002, approximately 85% of our credit portfolio was rated at least investment grade by the major rating agencies, with 3% rated below investment grade and 12% not rated. Of the portion not rated, 84% primarily represents governmental entities, municipalities, cooperatives, power pools, or other load-serving entities that we assess are equivalent to investment grade based on internal credit ratings.

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 origination and risk management operation had contracted for), we could sustain 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, we would have to make to settle unrealized losses on accrual contracts.

Equity Price Risk

We are exposed to price fluctuations in equity markets primarily through our financial investments operation, our pension plan assets, and our nuclear decommissioning trust funds. We are required by the NRC to maintain an externally funded trust 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 $65 million reduction in the fair value of our financial investments that are classified as trading or available-for-sale securities. In 2002, the value of our defined benefit pension plan assets decreased by approximately $90 million due to declines 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 6*.

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

The management of Constellation Energy and BGE (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.

The Companies maintain an accounting system and related system of internal controls designed to provide reasonable assurance that the financial records are accurate and that the Companies' assets are protected. The Companies' staff of internal auditors, which reports directly to the Chief Financial Officer, conducts periodic reviews to maintain the effectiveness of internal control procedures. PricewaterhouseCoopers LLP, independent accountants, audit the financial statements and express their opinion on them. They perform their audit in accordance with auditing standards generally accepted in the United States of America.

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.

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

REPORT OF INDEPENDENT ACCOUNTANTS

To the Shareholders of Constellation Energy Group, Inc. and 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 Constellation Energy Group, Inc. and Subsidiaries and of Baltimore Gas and Electric Company and Subsidiaries at December 31, 2002 and 2001, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2002 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. of this Form 10-K 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 the financial statement schedule are the responsibility of the Companies' 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 auditing standards generally accepted in the United States of America, which 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.

We have also previously audited, in accordance with auditing standards generally accepted in the United States of America, the consolidated balance sheets and statement of capitalization of Constellation Energy Group, Inc. and Subsidiaries and of Baltimore Gas and Electric Company and Subsidiaries as of December 31, 2000, 1999 and 1998, and the related consolidated statements of income, cash flows, and common shareholders' equity and comprehensive income for the years ended December 31, 1999 and 1998 (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. included in the Selected Financial Data for each of the five years in the period ended December 31, 2002, and the information set forth in the Summary of Operations and Summary of Financial Condition of Baltimore Gas and Electric Company included in the Selected Financial Data for each of the five years in the period ended December 31, 2002, is fairly stated, in all material respects, in relation to the consolidated financial statements from which it has been derived.

As discussed in *Note 1* to the consolidated financial statements, in 2001, the Companies changed their method of accounting for derivative and hedging activities pursuant to Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended by Statement of Financial Accounting Standards No. 138, *Accounting for Certain Derivative Instruments and Certain Hedging Activities (an amendment of FASB Statement No. 133).*

PricewaterhouseCoopers LLP
Baltimore, Maryland
January 29, 2003

CONSOLIDATED STATEMENTS OF INCOME

Constellation Energy Group, Inc. and Subsidiaries

Year Ended December 31,	2002	2001	2000
		(In millions, except per share amounts)	
Revenues			
Nonregulated revenues	**$ 2,166.9**	$ 1,164.9	$ 1,035.9
Regulated electric revenues	**1,965.6**	2,039.6	2,134.7
Regulated gas revenues	**570.5**	674.3	603.8

Year Ended December 31,	2002	2001	2000
Total revenues	**4,703.0**	3,878.8	3,774.4
Expenses			
Operating expenses	**3,049.9**	2,392.2	2,311.4
Workforce reduction costs	**62.8**	105.7	7.0
Impairment losses and other costs	**25.2**	158.8	
Contract termination related costs		224.8	
Depreciation and amortization	**481.0**	419.1	470.0
Taxes other than income taxes	**259.2**	226.6	221.5
Total expenses	**3,878.1**	3,527.2	3,009.9
Net Gain on Sales of Investments and Other Assets	**261.3**	6.2	78.1
Income from Operations	**1,086.2**	357.8	842.6
Other Income	**30.5**	1.3	4.2
Fixed Charges			
Interest expense	**312.3**	283.2	282.4
Interest capitalized and allowance for borrowed funds used during construction	**(44.0)**	(57.6)	(24.2)
BGE preference stock dividends	**13.2**	13.2	13.2
Total fixed charges	**281.5**	238.8	271.4
Income Before Income Taxes	**835.2**	120.3	575.4
Income Taxes	**309.6**	37.9	230.1
Income Before Cumulative Effect of Change in Accounting Principle	**525.6**	82.4	345.3
Cumulative Effect of Change in Accounting Principle, Net of Income Taxes of $5.6 (see Note 1)		8.5	
Net Income	**$ 525.6**	$ 90.9	$ 345.3
Earnings Applicable to Common Stock	**$ 525.6**	$ 90.9	$ 345.3
Average Shares of Common Stock Outstanding	**164.2**	160.7	150.0
Earnings Per Common Share and Earnings Per Common Share Assuming Dilution Before Cumulative Effect of Change in Accounting Principle	**$ 3.20**	$ .52	$ 2.30
Cumulative Effect of Change in Accounting Principle		.05	
Earnings Per Common Share and Earnings Per Common Share Assuming Dilution	**$ 3.20**	$ .57	$ 2.30

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,

	2002	2001
	(In millions)	
Assets		
Current Assets		
Cash and cash equivalents	**$ 615.0**	$ 72.4
Accounts receivable (net of allowance for uncollectibles of **$41.9** and $22.8, respectively)	**1,247.3**	738.9
Trading securities	**77.1**	178.2
Mark-to-market energy assets	**144.0**	398.4
Risk management assets	**72.3**	65.2
Fuel stocks	**126.5**	110.2
Materials and supplies	**208.6**	210.2
Prepaid taxes other than income taxes	**57.1**	64.7
Other	**153.9**	58.0
Total current assets	**2,701.8**	1,896.2
Investments and Other Assets		
Real estate projects and investments	**86.1**	210.7
Investments in qualifying facilities and power projects	**439.2**	499.1
Investment in Orion Power Holdings, Inc.		442.5
Financial investments	**36.9**	60.7
Nuclear decommissioning trust funds	**645.4**	683.5
Mark-to-market energy assets	**1,348.2**	1,819.8
Risk management assets	**88.8**	77.6
Goodwill	**115.9**	
Other	**167.8**	132.8
Total investments and other assets	**2,928.3**	3,926.7
Property, Plant and Equipment		
Regulated property, plant and equipment		
Plant in service	**4,952.4**	4,862.4
Construction work in progress	**118.3**	81.8
Plant held for future use	**4.5**	4.5
Total regulated property, plant and equipment	**5,075.2**	4,948.7
Nonregulated generation property, plant and equipment	**6,811.9**	6,538.7

At December 31,

	2002	2001
Other nonregulated property, plant and equipment	**242.0**	192.9
Nuclear fuel (net of amortization)	**224.8**	174.8
Accumulated depreciation	**(4,396.8)**	(4,161.8)
Net property, plant and equipment	**7,957.1**	7,693.3
Deferred Charges		
Regulatory assets (net)	**405.7**	463.8
Other	**136.0**	129.4
Total deferred charges	**541.7**	593.2
Total Assets	**$ 14,128.9**	$ 14,109.4

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,

	2002	2001
	(In millions)	
Liabilities and Equity		
Current Liabilities		
Short-term borrowings	**$ 10.5**	$ 975.0
Current portion of long-term debt	**426.2**	1,406.7
Accounts payable	**943.4**	523.3
Mark-to-market energy liabilities	**94.1**	323.3
Risk management liabilities	**20.1**	11.7
Dividends declared	**42.8**	23.0
Accrued interest	**95.5**	57.7
Other	**392.8**	250.4
Total current liabilities	**2,025.4**	3,571.1
Deferred Credits and Other Liabilities		
Deferred income taxes	**1,330.7**	1,431.0
Mark-to-market energy liabilities	**881.5**	1,476.5
Risk management liabilities	**149.5**	12.5
Net pension liability	**334.6**	215.5
Postretirement and postemployment benefits	**352.8**	330.9

At December 31,	2002	2001
Deferred investment tax credits	**85.7**	93.4
Other	**197.2**	130.7
Total deferred credits and other liabilities	**3,332.0**	3,690.5
Capitalization (See Statement of Capitalization)		
Long-term debt	**4,613.9**	2,712.5
Minority interests	**105.3**	101.7
BGE preference stock not subject to mandatory redemption	**190.0**	190.0
Common shareholders' equity	**3,862.3**	3,843.6
Total capitalization	**8,771.5**	6,847.8
Commitments, Guarantees, and Contingencies (see Note 11)		
Total Liabilities and Equity	**$ 14,128.9**	$ 14,109.4

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

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CONSOLIDATED STATEMENTS OF CASH FLOWS

Constellation Energy Group, Inc. and Subsidiaries

Year Ended December 31,	2002	2001	2000
		(In millions)	
Cash Flows From Operating Activities			
Net income	**$ 525.6**	$ 90.9	$ 345.3
Adjustments to reconcile to net cash provided by operating activities			
Cumulative effect of change in accounting principle		(8.5)	
Depreciation and amortization	**548.0**	468.9	524.8
Deferred income taxes	**148.3**	(26.5)	42.1
Investment tax credit adjustments	**(7.9)**	(8.1)	(8.4)
Deferred fuel costs	**23.9**	37.6	2.8
Pension and postemployment benefits	**(116.2)**	55.3	27.9
Net gain on sales of investments and other assets	**(261.3)**	(6.2)	(78.1)
Workforce reduction costs	**62.8**	105.7	7.0
Impairment losses and other costs	**25.2**	158.8	
Contract termination related costs		26.2	
Deregulation transition cost			24.0
Equity in earnings of affiliates less than (in excess of) dividends received	**67.0**	2.0	(5.3)

Year Ended December 31,	2002	2001	2000
Changes in			
Accounts receivable	**(236.8)**	53.7	(214.1)
Mark-to-market energy assets and liabilities	**(133.7)**	109.5	(379.6)
Risk management assets and liabilities	**58.6**	(93.2)	
Materials, supplies and fuel stocks	**(11.7)**	(90.9)	14.5
Other current assets	**130.3**	(20.5)	(31.1)
Accounts payable	**188.4**	(226.7)	384.9
Other current liabilities	**50.4**	7.8	21.3
Other	**(40.9)**	(62.5)	172.9
Net cash provided by operating activities	**1,020.0**	573.3	850.9
Cash Flows From Investing Activities			
Purchases of property, plant and equipment	**(831.9)**	(1,302.5)	(1,067.0)
Acquisitions, net of cash acquired	**(221.4)**	(382.7)	
Contributions to nuclear decommissioning trust funds	**(17.6)**	(22.0)	(13.2)
Payments for structured deal fees	**(51.4)**		
Sale of (investment in) Orion	**454.1**	26.2	(101.5)
Sale of investments and other assets	**383.9**	260.9	169.9
Purchases of marketable equity securities	**(0.2)**	(33.2)	(80.8)
Other investments	**(35.3)**	(19.4)	(13.9)
Net cash used in investing activities	**(319.8)**	(1,472.7)	(1,106.5)
Cash Flows From Financing Activities			
Net issuance (maturity) of short-term borrowings	**(964.5)**	731.4	(127.9)
Proceeds from issuance of			
Long-term debt	**2,529.3**	1,175.2	1,374.0
Common stock	**28.5**	504.4	35.9
Repayment of long-term debt	**(1,627.7)**	(1,510.2)	(697.0)
Common stock dividends paid	**(137.8)**	(120.7)	(250.7)
Other	**14.6**	9.0	11.3
Net cash (used in) provided by financing activities	**(157.6)**	789.1	345.6
Net Increase (Decrease) in Cash and Cash Equivalents	**542.6**	(110.3)	90.0
Cash and Cash Equivalents at Beginning of Year	**72.4**	182.7	92.7
Cash and Cash Equivalents at End of Year	**$ 615.0**	$ 72.4	$ 182.7
Other Cash Flow Information:			
Cash paid during the year for:			
Interest (net of amounts capitalized)	**$ 230.5**	$ 238.3	$ 268.2
Income taxes	**$ 157.8**	$ 101.5	$ 184.7

Non-Cash Transaction:

In connection with our purchase of Nine Mile Point in 2001, the fair value of the net assets purchased was $770.8 million. We paid $382.7 million in cash, including settlement costs, and incurred a sellers' note of $388.1 million as discussed further in *Note 14*.

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

Years Ended December 31, 2002, 2001, and 2000	**Common Stock**		**Retained**	**Accumulated Other Comprehensive**	**Total**
	Shares	**Amount**	**Earnings**	**Income**	**Amount**
	(Dollar amounts in millions, number of shares in thousands)				
Balance at December 31, 1999	149,556	$ 1,494.0	$ 1,499.1	$ 24.4	$ 3,017.5
Comprehensive Income					
Net income			345.3		345.3
Other comprehensive income (OCI)					
Reclassification of net gain on sales of securities from OCI to net income, net of taxes of $18.4				(28.1)	(28.1)
Net unrealized gain on securities, net of taxes of $27.9				46.7	46.7
Total Comprehensive Income					363.9
Common stock dividend declared ($1.68 per share)			(251.8)		(251.8)
Common stock issued	976	35.9			35.9
Other		8.8	(0.3)		8.5
Balance at December 31, 2000	150,532	1,538.7	1,592.3	43.0	3,174.0
Comprehensive Income					
Net income			90.9		90.9
Other comprehensive income					
Cumulative effect of change in accounting principle, net of taxes of $22.6				(35.5)	(35.5)
Reclassification of net gain on sales of securities from OCI to net income, net of taxes of $15.7				(24.0)	(24.0)
Net unrealized gain on securities, net of taxes of $87.5				148.5	148.5
Net unrealized gain on hedging instruments, net of taxes of $65.6				102.6	102.6
Minimum pension liability, net of taxes of $29.3				(44.7)	(44.7)
Total Comprehensive Income					237.8
Common stock dividend declared ($.48 per share)			(77.1)		(77.1)
Common stock issued	13,176	504.4			504.4
Other		(0.9)	5.4		4.5
Balance at December 31, 2001	163,708	2,042.2	1,611.5	189.9	3,843.6

	Shares	Amount	Retained Earnings	Accumulated Other Comprehensive Income	Total
Comprehensive Income					
Net income			**525.6**		**525.6**
Other comprehensive income					
Reclassification of net gain on sales of securities from OCI to net income, net of taxes of $87.7				**(152.8)**	**(152.8)**
Reclassification of net gains on hedging instruments from OCI to net income, net of taxes of $10.9				**(17.8)**	**(17.8)**
Net unrealized loss on securities, net of taxes of $28.6				**(43.2)**	**(43.2)**
Net unrealized loss on hedging instruments, net of taxes of $31.7				**(52.2)**	**(52.2)**
Minimum pension liability, net of taxes of $77.2				**(118.1)**	**(118.1)**
Total Comprehensive Income					**141.5**
Common stock dividend declared ($.96 per share)			**(157.6)**		**(157.6)**
Common stock issued	**1,135**	**28.5**			**28.5**
Other		**8.2**	**(1.9)**		**6.3**
Balance at December 31, 2002	**164,843**	**$ 2,078.9**	**$ 1,977.6**	**$ (194.2)**	**$ 3,862.3**

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

CONSOLIDATED STATEMENTS OF CAPITALIZATION

Constellation Energy Group, Inc. and Subsidiaries

At December 31,

	2002	2001
	(In millions)	
Long-Term Debt		
Long-term debt of Constellation Energy		
Floating rate notes, due January 17, 2002	**$**	$ 635.0
$7\frac{7}{8}$% Notes, due April 1, 2005	**300.0**	300.0
6.35% Fixed Rate Notes, due April 1, 2007	**600.0**	
6.125% Fixed Rate Notes, due September 1, 2009	**500.0**	
7.00% Fixed Rate Notes, due April 1, 2012	**700.0**	
7.60% Fixed Rate Notes, due April 1, 2032	**700.0**	
Total long-term debt of Constellation Energy	**2,800.0**	935.0
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
Adjustable rate pollution control loan, due July 1, 2014	**20.0**	20.0

At December 31,

	2002	2001
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
5 1/2% Installment series, due July 15, 2002		6.7
District Cooling facilities loan, due December 1, 2031	**25.0**	25.0
Loans under revolving credit agreements	**51.7**	46.0
11% Installment note, due November 7, 2006		388.1
Mortgage and construction loans		
Floating rate mortgage notes and construction loans, due through 2005		13.8
4.25% Mortgage note, due March 15, 2009	**3.3**	19.7
Total long-term debt of nonregulated businesses	**349.8**	769.1
First Refunding Mortgage Bonds of BGE		
7 1/4% Series, due July 1, 2002		124.0
6 1/2% Series, due February 15, 2003	**124.8**	124.8
6 1/8% Series, due July 1, 2003	**124.9**	124.9
5 1/2% Series, due April 15, 2004	**125.0**	125.0
Remarketed floating rate series, due September 1, 2006	**111.5**	111.5
7 1/2% Series, due January 15, 2007	**123.5**	123.5
6 5/8% Series, due March 15, 2008	**124.9**	124.9
7 1/2% Series, due March 1, 2023	**98.1**	98.1
7 1/2% Series, due April 15, 2023	**72.2**	84.0
Total First Refunding Mortgage Bonds of BGE	**904.9**	1,040.7
Other long-term debt of BGE		
5.25% Notes, due December 15, 2006	**300.0**	300.0
Floating rate reset notes, due February 5, 2002		200.0
Medium-term notes, Series B	**12.1**	23.1
Medium-term notes, Series C	**25.5**	25.5
Medium-term notes, Series D	**68.0**	68.0
Medium-term notes, Series E	**199.5**	200.0
Medium-term notes, Series G	**140.0**	140.0
6.75% Remarketable or redeemable securities, due December 15, 2012		173.0
Total other long-term debt of BGE	**745.1**	1,129.6
BGE obligated mandatorily redeemable trust preferred securities of subsidiary trust holding solely 7.16% deferrable interest subordinated debentures due June 30, 2038	**250.0**	250.0
Unamortized discount and premium	**(9.7)**	(5.2)
Current portion of long-term debt	**(426.2)**	(1,406.7)
Total long-term debt	**$ 4,613.9**	$ 2,712.5

See Notes to Consolidated Financial Statements.

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CONSOLIDATED STATEMENTS OF CAPITALIZATION

Constellation Energy Group, Inc. and Subsidiaries

At December 31,

	2002		2001	
	(In millions)			
Minority Interests	**$**	**105.3**	$	101.7
BGE Preference Stock				
Cumulative preference stock not subject to mandatory redemption, 6,500,000 shares authorized				
7.125%, 1993 Series, 400,000 shares outstanding, not callable prior to July 1, 2003		**40.0**		40.0
6.97%, 1993 Series, 500,000 shares outstanding, not callable prior to October 1, 2003		**50.0**		50.0
6.70%, 1993 Series, 400,000 shares outstanding, not callable prior to January 1, 2004		**40.0**		40.0
6.99%, 1995 Series, 600,000 shares outstanding, not callable prior to October 1, 2005		**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; 164,842,708 and 163,707,950 shares issued and outstanding at December 31, 2002 and 2001, respectively. (At December 31, 2002, 18,000,000 shares were reserved for the long-term incentive plans, 11,451,868 shares were reserved for the Shareholder Investment Plan, 1,806,100 shares were reserved for the continuous offering programs, and 1,505,863 shares were reserved for the employee savings plan.)		**2,078.9**		2,042.2
Retained earnings		**1,977.6**		1,611.5
Accumulated other comprehensive (loss) income		**(194.2)**		189.9
Total common shareholders' equity		**3,862.3**		3,843.6
Total Capitalization	**$**	**8,771.5**	$	6,847.8

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

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CONSOLIDATED STATEMENTS OF INCOME

Baltimore Gas and Electric Company and Subsidiaries

Year Ended December 31,

	2002		2001		2000	
			(In millions)			
Revenues						
Electric revenues	**$**	**1,966.0**	$	2,040.0	$	2,135.2
Gas revenues		**581.3**		680.7		611.6

Year Ended December 31,	2002	2001	2000
Total revenues	**2,547.3**	2,720.7	2,746.8
Expenses			
Operating Expenses			
Electric fuel and purchased energy	**1,080.7**	1,192.8	870.7
Gas purchased for resale	**316.7**	401.3	350.6
Operations and maintenance	**355.3**	363.0	547.4
Workforce reduction costs	**35.3**	57.0	7.0
Depreciation and amortization	**221.6**	221.0	366.1
Taxes other than income taxes	**171.4**	173.8	192.6
Total expenses	**2,181.0**	2,408.9	2,334.4
Income from Operations	**366.3**	311.8	412.4
Other Income	**10.7**	0.4	7.5
Fixed Charges			
Interest expense	**142.1**	156.2	187.2
Allowance for borrowed funds used during construction	**(1.5)**	(1.6)	(3.2)
Total fixed charges	**140.6**	154.6	184.0
Income Before Income Taxes	**236.4**	157.6	235.9
Income Taxes			
Current	**67.4**	62.4	142.1
Deferred	**28.0**	0.2	(44.4)
Investment tax credit adjustments	**(2.1)**	(2.3)	(5.3)
Total income taxes	**93.3**	60.3	92.4
Net Income	**143.1**	97.3	143.5
Preference Stock Dividends	**13.2**	13.2	13.2
Earnings Applicable to Common Stock	**$ 129.9**	$ 84.1	$ 130.3

See Notes to Consolidated Financial Statements.

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CONSOLIDATED BALANCE SHEETS

Baltimore Gas and Electric Company and Subsidiaries

At December 31,	2002	2001
	(In millions)	
Assets		
Current Assets		
Cash and cash equivalents	**$ 10.2**	$ 37.4
	357.5	295.2

At December 31,	2002	2001
Accounts receivable (net of allowance for uncollectibles of **$11.5** and $13.4, respectively)		
Investment in cash pool, affiliated company	**338.1**	439.1
Accounts receivable, affiliated companies	**131.2**	63.4
Fuel stocks	**40.6**	52.3
Materials and supplies	**31.8**	33.1
Prepaid taxes other than income taxes	**42.0**	43.8
Other	**10.3**	36.3
Total current assets	**961.7**	1,000.6
Other Assets		
Receivable, affiliated company	**63.3**	183.3
Other	**85.9**	74.5
Total other assets	**149.2**	257.8
Utility Plant		
Plant in service		
Electric	**3,422.3**	3,349.9
Gas	**1,041.0**	1,014.4
Common	**489.1**	498.1
Total plant in service	**4,952.4**	4,862.4
Accumulated depreciation	**(1,851.4)**	(1,751.4)
Net plant in service	**3,101.0**	3,111.0
Construction work in progress	**118.3**	81.8
Plant held for future use	**4.5**	4.5
Net utility plant	**3,223.8**	3,197.3
Deferred Charges		
Regulatory assets (net)	**405.7**	463.8
Other	**39.5**	35.0
Total deferred charges	**445.2**	498.8
Total Assets	**$ 4,779.9**	$ 4,954.5

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

CONSOLIDATED BALANCE SHEETS

Baltimore Gas and Electric Company and Subsidiaries

At December 31,	**2002**	**2001**
	(In millions)	
Liabilities and Equity		
Current Liabilities		
Current portions of long-term debt	$ **420.7**	$ 666.3
Accounts payable	**103.2**	63.6
Accounts payable, affiliated companies	**85.6**	92.6
Customer deposits	**54.2**	50.0
Accrued taxes	**9.0**	7.6
Accrued interest	**31.4**	37.0
Accrued vacation costs	**19.5**	21.7
Other	**30.2**	39.2
Total current liabilities	**753.8**	978.0
Deferred Credits and Other Liabilities		
Deferred income taxes	**528.9**	503.1
Postretirement and postemployment benefits	**278.0**	266.1
Deferred investment tax credits	**20.5**	22.7
Decommissioning of federal uranium enrichment facilities	**14.6**	19.3
Other	**13.9**	17.2
Total deferred credits and other liabilities	**855.9**	828.4
Long-term Debt		
First refunding mortgage bonds of BGE	**904.9**	1,040.7
Other long-term debt of BGE	**745.1**	1,129.6
Company obligated mandatorily redeemable trust preferred securities of subsidiary trust holding solely 7.16% debentures of BGE due June 30, 2038	**250.0**	250.0
Long-term debt of nonregulated businesses	**25.0**	71.0
Unamortized discount and premium	**(5.2)**	(3.3)
Current portion of long-term debt	**(420.7)**	(666.3)
Total long-term debt	**1,499.1**	1,821.7
Minority Interest	**19.4**	5.0
Preference Stock Not Subject to Mandatory Redemption	**190.0**	190.0
Common Shareholder's Equity		

At December 31,

	2002	2001
Common stock	**912.2**	711.9
Retained earnings	**549.5**	419.5
Total common shareholder's equity	**1,461.7**	1,131.4
Commitments, Guarantees, and Contingencies (see Note 11)		
Total Liabilities and Equity	**$ 4,779.9**	$ 4,954.5

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

Baltimore Gas and Electric Company and Subsidiaries

Year Ended December 31,

	2002	2001	2000
		(In millions)	
Cash Flows From Operating Activities			
Net income	**$ 143.1**	$ 97.3	$ 143.5
Adjustments to reconcile to net cash provided by operating activities			
Depreciation and amortization	**224.4**	223.3	393.6
Deferred income taxes	**28.0**	0.2	(44.4)
Investment tax credit adjustments	**(2.1)**	(2.3)	(5.3)
Deferred fuel costs	**23.9**	37.6	2.8
Pension and postemployment benefits	**(40.7)**	14.7	16.1
Allowance for equity funds used during construction	**(2.8)**	(3.0)	(2.6)
Workforce reduction costs	**35.3**	57.0	7.0
Changes in			
Accounts receivable	**(62.3)**	117.8	(101.4)
Receivables, affiliated companies	**52.2**	(113.5)	(128.7)
Materials, supplies and fuel stocks	**13.0**	(14.0)	11.1
Other current assets	**27.8**	(30.5)	31.8
Accounts payable	**39.6**	(55.7)	(88.6)
Accounts payable, affiliated companies	**(7.0)**	(10.9)	98.8
Other current liabilities	**(11.2)**	(7.7)	(7.1)
Other	**33.2**	61.5	68.1
Net cash provided by operating activities	**494.4**	371.8	394.7
Cash Flows From Investing Activities			
Utility construction expenditures (excluding equity portion of AFC)	**(216.7)**	(236.4)	(309.5)
Investment in cash pool at parent	**101.0**	(441.1)	2.0
Nuclear fuel expenditures			(39.5)

Year Ended December 31,	2002	2001	2000
Contributions to nuclear decommissioning trust fund			(8.8)
Other	**(17.0)**	(20.9)	0.1
Net cash used in investing activities	**(132.7)**	(698.4)	(355.7)
Cash Flows From Financing Activities			
Net maturity of short-term borrowings		(32.1)	(96.9)
Proceeds from issuance of long-term debt		532.1	377.3
Repayment of long-term debt	**(575.5)**	(394.1)	(121.7)
Preference stock dividends paid	**(13.2)**	(13.2)	(13.2)
Distribution from (to) parent	**200.0**	250.0	(188.5)
Other	**(0.2)**		1.8
Net cash (used in) provided by financing activities	**(388.9)**	342.7	(41.2)
Net (Decrease) Increase in Cash and Cash Equivalents	**(27.2)**	16.1	(2.2)
Cash and Cash Equivalents at Beginning of Year	**37.4**	21.3	23.5
Cash and Cash Equivalents at End of Year	**$ 10.2**	$ 37.4	$ 21.3
Other Cash Flow Information			
Cash paid during the year for:			
Interest (net of amounts capitalized)	**$ 147.5**	$ 162.0	$ 184.7
Income taxes	**$ 36.6**	$ 102.8	$ 127.6

Noncash Investing and Financing Activities:

On July 1, 2000, BGE transferred $1,578.4 million of generation assets, net of associated liabilities, to nonregulated affiliates of Constellation Energy as a result of the deregulation of electric generation.

See Notes to Consolidated Financial Statements.

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1 Significant Accounting Policies

Nature of Our Business

Constellation Energy Group, Inc. (Constellation Energy) is a North American 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 large customers. BGE is a regulated electric and gas public transmission and 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 "utility business" are to BGE.

Consolidation Policy

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

Consolidation

We use consolidation when we own a majority of the voting stock of the subsidiary. This means the accounts of our subsidiaries are combined with our accounts. We eliminate intercompany balances and transactions when we consolidate these accounts. We discuss the implications of the Financial Accounting Standards Board (FASB) Interpretation No. 46, *Consolidation of Variable Interest Entities* on our future consolidation policy later in this Note.

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 Utility 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 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 Consolidated Balance Sheets and exclude from our Consolidated Statements of Income) certain utility expenses and income as regulatory assets and liabilities. We have recorded these regulatory assets and liabilities in our Consolidated Balance Sheets in accordance with Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulation.*

In addition, the FASB through its Emerging Issues Task Force (EITF) issued EITF 97-4, *Deregulation of the Pricing of Electricity Issues Related to the Application of FASB Statements No. 71 and 101.* The EITF concluded that a company should cease to apply SFAS No. 71 when either legislation is passed or a regulatory body issues an order that contains sufficient detail to determine how the transition plan will affect the deregulated portion of the business. Additionally, a company would continue to recognize regulatory assets and liabilities in the Consolidated Balance Sheets to the extent that the transition plan provides for their recovery.

We summarize and discuss our regulatory assets and liabilities further in *Note 5*.

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 assets and liabilities in our Consolidated Balance Sheets at the dates of the financial statements,

our disclosure of contingent assets and liabilities at the dates of the financial statements, and

our reported amounts of revenues and expenses in our Consolidated Statements of Income during the reporting periods.

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.

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Reclassifications

We have reclassified certain prior-year amounts for comparative purposes. These reclassifications did not affect consolidated net income for the years presented.

Revenues

Nonregulated Businesses

We record nonregulated business revenues using two methods of accounting: accrual accounting and mark-to-market accounting. We use accrual accounting for our merchant energy business transactions, including non-trading long-term power sales contracts that are not subject to mark-to-market accounting. Transactions subject to accrual accounting include the generation or purchase and sale of electricity and gas as part of our physical delivery activities. Under accrual accounting, we record revenues in the period earned for services rendered, commodities or products delivered, or contracts settled.

We use mark-to-market accounting for energy trading activities and for derivatives and other contracts for which we are not permitted to use accrual accounting or hedge accounting. We discuss our use of hedge accounting in the *Risk Management and Hedging Activities* section later in this Note. These mark-to-market activities include derivative and (prior to EITF 02-3) non-derivative contracts for energy and other energy-related commodities. Under the mark-to-market method of accounting, we record the fair value of energy contracts as mark-to-market energy assets and liabilities at the time of contract execution. We record reserves to reflect uncertainties associated with certain estimates inherent in the determination of fair value. To the extent possible, we utilize market-based data together with quantitative methods for both measuring the risks for which we record reserves and determining the level of such reserves and changes in those levels.

We describe below the main types of reserves we record and the process for establishing each.

Close-out reserve this reserve represents the estimated cost to close out or sell to a third-party open mark-to-market positions. This reserve has the effect of valuing "long" positions at the bid price and "short" positions at the offer price. We compute this reserve based on our estimate of the bid/offer spread for each commodity and option price and the absolute quantity of our open positions for each year. Effective July 1, 2002, to the extent that we are not able to obtain market information for similar contracts, the close-out reserve is equivalent to the initial contract margin, thereby recording no gain or loss at inception. The level of total close-out reserves 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.

Credit-spread adjustment for risk management purposes, we compute the value of our mark-to-market 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 assets to reflect the credit-worthiness of each individual counterparty based upon published credit ratings, where available, or equivalent internal credit ratings and associated default probability percentages. We compute this reserve by applying the appropriate default probability percentage to our outstanding credit exposure, net of collateral, for each counterparty.

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 positions,
- net gains and losses from realized transactions, and
- changes in reserves.

We record the changes in mark-to-market energy assets and liabilities on a net basis in "Nonregulated revenues" in our Consolidated Statements of Income. At December 31, 2002, mark-to-market energy assets and liabilities consist of a combination of energy and energy-related derivative and non-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.

During 2002, the FASB issued EITF 02-3, *Recognition and Reporting of Gains and Losses on Energy Trading Contracts Under EITF Issues No. 98-10 and No. 00-17* that changed the accounting for energy contracts. These changes include requiring the accrual method of accounting for energy contracts that are not derivatives and clarifying when gains or losses can be recognized at the inception of derivative contracts. We discuss EITF 02-3 in more detail in the *Recently Issued Accounting Standards* section later in this Note.

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 the balance sheets in accordance with FASB Interpretation No. 39, *Offsetting of Amounts Related to Certain Contracts*.

We also include equity in earnings from our investments in qualifying facilities and power projects in revenues.

Regulated Utility

We record utility revenues when we provide service to customers.

Fuel and Purchased Energy Costs

We incur costs for:

- the fuel we use to generate electricity,
- purchases of electricity from others, and
- natural gas that we resell.

These costs are included in "Operating expenses" in our Consolidated Statements of Income. We discuss each of these separately below.

Fuel Used to Generate Electricity and Purchases of Electricity From Others

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.

Our accrual-basis third-party fuel and purchased energy expenses were as follows:

	2002	2001	2000
	(In millions)		
Fuel and Purchased Energy	**$ 1,144.2**	$ 479.6	$ 429.7

Effective July 1, 2000, these costs are recorded as incurred. Historically and until July 1, 2000, we were allowed to recover our costs of electric fuel under the electric fuel rate clause set by the Maryland PSC. Under the electric fuel rate clause, we charged our electric customers for:

- the fuel we used to generate electricity (nuclear fuel, coal, gas, or oil), and
- the net cost of purchases and sales of electricity.

We charged the actual costs of these items to customers with no profit to us. To do this, we had to keep track of what we spent and what we collected from customers under the fuel rate in a given period. Usually these two amounts were not the same because there was a difference between the time we spent the money and the time we collected it from our customers.

Under the electric fuel rate clause, we deferred the difference between our actual costs of fuel and energy and what we collected from customers under the fuel rate in a given period. We either billed or refunded our customers that difference in the future. As a result of the deregulation of electric generation, the fuel rate was discontinued effective July 1, 2000.

Natural Gas

We charge our gas customers for the natural gas they purchase from us using "gas cost adjustment clauses" set by the Maryland PSC. These clauses operate similarly to the electric fuel rate clause described earlier in this Note. However, the Maryland PSC approved a modification of the gas cost adjustment clauses to provide a market-based rates incentive mechanism. Under market-based rates, 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. Effective November 2001, the Maryland PSC approved an order 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.

Risk Management and Hedging Activities

Market Risks

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 12*. SFAS No. 133, as amended by SFAS No. 138, *Accounting for Certain Derivative Instruments and Certain Hedging Activities,* requires that we recognize all derivatives not qualifying for the normal purchase and normal sale exemption in our Consolidated Balance Sheets at fair value. Changes in the value of derivatives that are not hedges must be recorded in earnings. Under SFAS No. 133, changes in the value of derivatives designated as cash-flow hedges that are effective in offsetting the variability in cash flows of forecasted transactions are recognized in other comprehensive income until the forecasted transactions occur. The ineffective portion of changes in fair value of derivatives used as cash-flow hedges is immediately recognized in earnings.

In accordance with the transition provisions of SFAS No. 133, we recorded the following at January 1, 2001:

- an $8.5 million after-tax cumulative effect adjustment that increased earnings, and
- a $35.5 million after-tax cumulative effect adjustment that reduced other comprehensive income.

The cumulative effect adjustment recorded in earnings represents the fair value as of January 1, 2001 of a warrant for 705,900 shares of common stock of Orion. The warrant had an exercise price of $10 per share and was received in conjunction with our investment in Orion. As part of the sale of Orion to Reliant Resources, Inc., we received cash equal to the difference between Reliant's purchase price of $26.80 per share and the exercise price multiplied by the number of shares subject to the warrant.

The cumulative effect adjustment recorded in other comprehensive income represents certain forward sales of electricity that we designated as cash-flow hedges of forecasted transactions primarily through our merchant energy business.

Interest Rate Swaps

We use interest rate swaps to manage our interest rate exposures associated with new debt issuances. These swaps are in anticipation of planned financing transactions and are designated as cash-flow hedges under SFAS No. 133, with our gains or losses recorded in "Risk management assets or liabilities" in our Consolidated Balance Sheets and "Accumulated other comprehensive income," in our Consolidated Statements of Common Shareholders' Equity and Consolidated Statements of Capitalization. Any gain or loss on the hedges will be reclassified from "Accumulated other comprehensive income" into "Interest expense" and be included in earnings during the periods in which the interest payments being hedged occur.

Commodity Prices

Our merchant energy and regulated gas businesses use derivative and non-derivative instruments to manage changes in their respective commodity prices as discussed in more detail below.

Merchant Energy Business

Our origination and risk management operation manages market risk on a portfolio basis, subject to established risk management policies. Our origination and risk management operation 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.

Under the provisions of SFAS No. 133, we record gains and losses on derivative contracts designated as cash-flow hedges of firm commitments or anticipated transactions in "Accumulated other comprehensive income" in our Consolidated Statements of Common Shareholders' Equity and Consolidated Statements of Capitalization prior to the settlement of the anticipated hedged physical transaction. We reclassify these gains or losses into earnings upon settlement of the underlying hedged transaction. We record derivatives used for hedging activities from our merchant energy business in "Risk management assets and liabilities" in our Consolidated Balance Sheets.

Regulated Gas Business

We use basis swaps in the winter months (November through March) to hedge our price risk associated with natural gas purchases under our market-based rates incentive mechanism. We also use fixed-to-floating and floating-to-fixed swaps to hedge our price risk associated with our off-system gas sales.

The fixed portion represents a specific dollar amount that we will pay or receive, and the floating portion represents a fluctuating amount based on a published index that we will receive or pay. Our regulated gas business internal guidelines do not permit the use of swap agreements for any purpose other than to hedge price risk.

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, monitoring 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, net of any unrealized losses, where we have a legally enforceable right of setoff.

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 origination and risk management operation had contracted for), we could sustain 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, we would have to make to settle unrealized losses on accrual contracts.

Electric and gas utilities, cooperatives, and energy marketers comprise the majority of counterparties underlying our assets from our origination and risk management activities. We held cash collateral from counterparties totaling $50.1 million as of December 31, 2002 and $3.5 million as of December 31, 2001. These amounts are included in "Other deferred credits and other liabilities" in our Consolidated Balance Sheets.

Taxes

We summarize our income taxes in *Note 9*. Our subsidiary income taxes are computed on a separate return basis. As you read this section, it may be helpful to refer to *Note 9*.

Income Tax Expense

We have two categories of income taxes 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.

Investment Tax Credits

We have deferred the investment tax credits associated with our regulated utility business and assets previously held by our regulated utility business in our Consolidated Balance Sheets. The investment tax credits are amortized evenly to income over the life of each property. We reduce income tax expense in our Consolidated Statements of Income for the investment tax credits and other tax credits associated with our nonregulated businesses, other than leveraged leases.

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 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 utility 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 5*.

State and Local Taxes

State and local income taxes are included in "Income taxes" in our Consolidated Statements of Income.

We also pay Maryland public service company franchise tax on transmission, 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. Stock options to purchase approximately 4.1 million shares in 2002, approximately 0.1 million shares in 2001, and approximately 1.4 million shares in 2000 were not dilutive and were excluded from the computation of diluted EPS for these respective years.

Stock-Based Compensation

Under our long-term incentive plans, we granted stock options, performance and service-based restricted stock, and equity to officers, key employees, and members of the Board of Directors. We discuss this in more detail in *Note 13*.

As permitted by SFAS No. 123, *Accounting for Stock-Based Compensation*, we measure our stock-based compensation in accordance with Accounting Principles Board Opinion (APB) No. 25, *Accounting for Stock Issued to Employees,* and related interpretations.

Our stock options are granted with an exercise price equal to the market value of the stock at the date of grant. Accordingly, no compensation expense is recorded for these awards. However, when we grant options subject to a contingency, we recognize compensation expense when options granted have an exercise price less than the market value of the underlying common stock on the date the contingency is satisfied. We amortize compensation expense for restricted stock over the performance/service period, which is typically a one to five year period.

The following table illustrates the effect on net income and earnings per share had we applied the fair value recognition provision of SFAS No. 123 to all outstanding stock option and stock awards in each year.

	2002	**2001**	**2000**
		(In millions, except per share amounts)	
Net income, as reported	**$ 525.6**	$ 90.9	$ 345.3
Add: Stock-based compensation expense included in reported net income, net of related tax effects	**6.1**	(6.1)	9.8
Deduct: Stock-based compensation expense determined under fair value based method for all awards, net of related tax effects	**(16.8)**	(0.9)	(9.0)
Pro-forma net income	**$ 514.9**	$ 83.9	$ 346.1
Earnings per share:			
Basic as reported	**$ 3.20**	$ .57	$ 2.30
Basic pro forma	**$ 3.14**	$ .52	$ 2.31
Diluted as reported	**$ 3.20**	$ .57	$ 2.30
Diluted pro forma	**$ 3.13**	$ .52	$ 2.31

In the table above, the stock-based compensation expense included in reported net income, net of related tax effects is as follows:

in 2002, $6.1 million, after-tax, or $10.1 million pre-tax comprised of $3.0 million of pre-tax expense for certain stock options, $6.6 million for restricted stock, and $0.5 million for equity grants,

in 2001, a $(6.1) million, after-tax, or $(10.1) million pre-tax reversal of expense for restricted stock as a result of non-attainment of performance criteria, and

in 2000, $9.8 million, after-tax, or $16.3 million pre-tax for restricted stock grants.

Cash and Cash Equivalents

All highly liquid investments with original maturities of three months or less are considered cash equivalents.

Inventory

We record our fuel stocks and materials and supplies at the lower of cost or market. We determine cost using the average cost method.

Real Estate Projects and Investments

In *Note 4*, we summarize the real estate projects and investments that are in our Consolidated Balance Sheets. At December 31, 2002, the projects and investments primarily consist of:

- approximately 500 acres of land holdings in various stages of development located at 6 sites in the central Maryland region, and
- an operating waste water treatment plant located in Anne Arundel County, Maryland.

The costs incurred to develop properties are included as part of the cost of the properties.

Financial Investments and Trading Securities

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. We classify these investments as either trading securities or available-for-sale securities, which we describe separately below. We report investments that are not covered by SFAS No. 115 at their cost.

Trading Securities

Our other nonregulated businesses classify some of their investments in marketable equity securities and financial limited partnerships as trading securities. We include any unrealized gains or losses on these securities in "Nonregulated revenues" in our Consolidated Statements of Income.

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 reserves under the heading "Nuclear Decommissioning" later in this Note.

In addition, our other nonregulated businesses classified some of their investments in marketable equity securities 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 Consolidated Statements of Capitalization.

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

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 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.

We determine if long-lived assets 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. 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*, provides the accounting 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 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.

Goodwill

Goodwill is the excess of the purchase price of an acquisition over the fair value of the net assets acquired. We do not amortize goodwill and certain other intangibles under the provisions of SFAS No. 142, *Goodwill and Other Intangible Assets.* SFAS No. 142 requires the evaluation of goodwill for impairment at least annually or more frequently if events and circumstances indicate that the asset might be impaired. We discuss our acquisitions in *Note 14*.

Property, Plant and Equipment, Depreciation, Amortization, and Decommissioning

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 and financing costs (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 $168 million at December 31, 2002 and $148 million at December 31, 2001. 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 generation property, plant and equipment" in our Consolidated Balance Sheets.

The "Nonregulated generation property, plant and equipment" in our Consolidated Balance Sheets includes nonregulated generation construction work in progress of $237.2 million at December 31, 2002 and $1,146.2 million at December 31, 2001.

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 composite, straight-line method. This includes regulated utility property, plant and equipment and nonregulated generating assets previously owned by the regulated utility. 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.

Depreciation Expense

We compute depreciation for our generating, electric transmission and distribution, and gas facilities over the estimated useful lives of depreciable property using either the:

- composite, straight-line rates (approved by the Maryland PSC for our regulated utility business) 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 three percent per year, or
- modified units of production method (greater of straight-line method or units of production method).

Other assets are depreciated using the straight-line method and the following estimated useful lives:

Asset	**Estimated Useful Lives**
Building and improvements	20 - 50 years
Transportation equipment	5 - 15 years
Office equipment and computer software	3 - 20 years

Amortization Expense

Amortization is an accounting process of reducing an amount in our Consolidated Balance Sheets evenly 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.

Nuclear Fuel

We amortize nuclear fuel based on the energy produced over the life of the fuel including the quarterly fees we pay to the Department of Energy for the future disposal of spent nuclear fuel. These fees are based on the kilowatt-hours of electricity sold. We report the amortization expense for nuclear fuel in "Operating expenses" in our Consolidated Statements of Income.

Nuclear Decommissioning

We record an expense and a reserve for the costs expected to be incurred in the future to decommission Calvert Cliffs based on a sinking fund methodology. The accumulated decommissioning reserve is recorded in "Accumulated depreciation" in our Consolidated Balance Sheets. The total reserve was $333.7 million at December 31, 2002 and $304.6 million at December 31, 2001. Our contributions to the nuclear decommissioning trust funds were $17.6 million for 2002, $22.0 million for 2001, and $13.2 million for 2000.

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 recorded a reserve for the costs expected to be incurred in the future to decommission Nine Mile Point under the discounted future cash flows methodology. The total reserve was $242.1 million at December 31, 2002 and $224.4 million at December 31, 2001. 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, 2002 and December 31, 2001.

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 and Nine Mile Point. 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.

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 in Constellation Energy or its affiliates and any other entity owning a nuclear power plant.

As owners of Calvert Cliffs Nuclear Power Plant, 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. We amortize 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.

Capitalized Interest and Allowance for Funds Used During Construction

Capitalized Interest

With the deregulation of electric generation, we ceased accruing AFC (discussed below) for electric generation-related construction projects.

Our nonregulated businesses capitalize interest costs under SFAS No. 34, *Capitalizing Interest Costs,* for costs incurred to finance our power plant construction projects and real estate developed for internal use.

Allowance for Funds Used During Construction (AFC)

We finance regulated utility construction projects with borrowed funds and equity funds. We are allowed by the Maryland PSC to record the costs of these funds as part of the cost of construction projects in our Consolidated Balance Sheets. We do this through the AFC, which we calculate using a rate authorized by the Maryland PSC. We bill our 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. We compound AFC annually.

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 to interest expense over the life of the debt.

When we incur gains or losses on debt that we retire prior to maturity in our regulated utility business, we amortize those gains or losses over the remaining original life of the debt.

Accounting Standards Adopted

SFAS No. 148

In December 2002, the Financial Accounting Standards Board (FASB) issued SFAS No. 148, *Accounting for Stock-Based Compensation Transition and Disclosure an amendment of FASB Statement No. 123.* SFAS No. 148 provides alternative methods of transition for a voluntary change to fair value-based methods of accounting for stock-based employee compensation. The Statement also amends the disclosure requirements of SFAS No. 123 to require prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method used on reported results. The provisions of the Statement were effective for financial statements for fiscal years ending after December 15, 2002.

Recently Issued Accounting Standards

SFAS No. 143

In 2001, the FASB issued SFAS No. 143, *Accounting for Asset Retirement Obligations.* SFAS No. 143 provides the accounting requirements for recognizing legal obligations associated with the retirement of tangible long-lived assets. This statement requires a cumulative effect of a change in accounting principle to be reported upon initial adoption and is effective for fiscal years beginning after June 15, 2002, with early adoption permitted. In January 2003, we recognized a net after-tax gain of approximately $68 million in accordance with this statement.

Substantially all of this net gain relates to the impact of adopting SFAS No. 143 on the measurement of the liability for the decommissioning of our Calvert Cliffs nuclear power plant. Losses on the adoption of SFAS No. 143 in other areas of our business are offset by the gain relating to the decommissioning of our Nine Mile Point nuclear power plant. The Calvert Cliffs' gain is primarily due to using a longer discount period as a result of license extension. The existing liability for the decommissioning of Calvert Cliffs was determined in accordance with ratemaking treatment established by the Maryland PSC and is based on a previous decommissioning cost estimate that contemplated decommissioning being completed at a point in time much closer to the expiration of the plant's original operating license.

As discussed earlier in this Note, we use the composite depreciation method for certain generating facilities and for our utility business. This method is currently an acceptable method of accounting under generally accepted accounting principles and is widely-used in the energy, transportation, and telecommunication industries. Under the composite depreciation method, the anticipated costs of removing assets upon retirement are provided for over the life of those assets as a component of depreciation expense.

However, the accounting profession has recently determined that SFAS No. 143 precludes the recognition of expected costs of retiring assets in excess of anticipated salvage proceeds as a component of depreciation expense or accumulated depreciation unless they are legal obligations under SFAS No. 143. Instead, we must recognize these costs as incurred.

We currently are evaluating the impact of this new guidance on our implementation of SFAS No. 143 and on our financial results. For our merchant energy business, we expect the elimination of cost of removal in excess of anticipated salvage proceeds from accumulated depreciation to increase the $68 million after-tax gain we recorded in January 2003 discussed above. On a comparable basis, we expect depreciation expense for 2003 and future years to be lower than prior years since the depreciation expense will no longer include a component for anticipated cost of removal in excess of salvage. Also, effective January 1, 2003 we will only record those asset removal costs that represent legal obligations under SFAS No. 143 prior to their being incurred.

As of the date of this report, we cannot determine the ultimate impact on the cumulative effect adjustment under SFAS No. 143 given the new accounting guidance. However, we expect the impact of this determination to be material to our financial results.

We do not expect the adoption of SFAS No. 143 to be material to BGE's financial results. BGE is required by the Maryland PSC to use the composite depreciation method under regulatory accounting. As a result, we expect the impact of the new guidance to be limited to a balance sheet reclassification of cost of removal from accumulated depreciation to regulatory assets and liabilities.

SFAS No. 146

In July 2002, the FASB issued SFAS No. 146, *Accounting for Exit or Disposal Activities*. SFAS No. 146 addresses significant issues regarding the recognition, measurement, and reporting of costs that are associated with exit and disposal activities, including restructuring activities that are currently accounted for under EITF 94-3. The provisions of the Statement will be effective for disposal activities initiated after December 31, 2002, with early application encouraged. We will reflect the requirements of this statement in any exit or disposal initiatives after its effective date.

FIN 45

In November 2002, the FASB issued Interpretation No. (FIN) 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others.* This Interpretation provides the disclosures to be made by a guarantor in interim and annual financial statements about obligations under certain guarantees. The Interpretation also clarifies that a guarantor is required to recognize, at the inception of a guarantee, a liability for the fair value of the obligation. The initial recognition and measurement requirements are effective prospectively for guarantees issued or modified after December 31, 2002. However, the disclosure requirements of the interpretation are effective for this Form 10-K and are included in *Note 11*.

FIN 46

In January 2003, the FASB issued FIN 46, *Consolidation of Variable Interest Entities*, that addresses conditions when an entity should be consolidated based upon variable interests rather than voting interests. Variable interests are ownership interests or contractual relationships that enable the holder to share in the financial risks and rewards resulting from the activities of a Variable Interest Entity (VIE). A VIE is a corporation, partnership, trust, or any other legal structure used for business purposes that either does not have equity investors with voting rights or has equity investors that do not provide sufficient financial resources for the entity to support its activities.

In order to apply FIN 46, we must evaluate every entity with which we are involved through variable interests to determine whether the entity is a VIE and, if it is, whether or not we are the primary beneficiary of the entity. The primary beneficiary of a VIE is the entity that receives the majority of the entity's expected losses, residual returns, or both. FIN 46 requires us to disclose information about significant variable interests we hold and to consolidate a VIE for which we are the primary beneficiary. As a result, FIN 46 could result in consolidation of an entity that we are associated with other than by (and even in the absence of) a voting ownership interest.

The requirements of FIN 46 apply immediately to all VIEs created after January 31, 2003 and are effective beginning in the third quarter of 2003 for all VIEs created before February 1, 2003. At the time of initially applying FIN 46 to previously unconsolidated VIEs, we will remove from our Consolidated Balance Sheets any previously recognized amounts related to those entities and record the carrying value of the assets, liabilities, and minority interest as reflected in their financial statements. The difference between the net amount added to the Consolidated Balance Sheets and the amounts removed (if any) upon initial adoption of FIN 46 must be recorded in earnings as the cumulative effect of an accounting change.

Based upon our initial review of entities with which we are involved through variable interests, we believe that some of these entities are VIEs for which we will have to make disclosures or which we will be required to consolidate when we apply FIN 46 in the third quarter of 2003. The VIEs for which we are the primary beneficiary (and therefore will have to consolidate) include the High Desert Power Project, a geothermal power project, the Safe Harbor Water Power Corporation, and an office building in Annapolis, Maryland, that we partially occupy. The other VIEs with which we are involved (but not as primary beneficiary) include certain other power projects and fuel processing facilities.

Our variable interests in these entities generally consist of equity investments and, in some instances, guarantees of the entities' debt or the value of the entities' assets. The following is summary information about these entities as of December 31, 2002:

	Primary Beneficiary	Significant Interest	Total
	(In millions)		
Total assets	$ 802	$ 472	$ 1,274
Total liabilities	618	419	1,037
Our ownership interest	124	19	143
Other ownership interests	60	34	94
Our maximum exposure to loss	662	68	730

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We believe that the net amount we will add to our Consolidated Balance Sheets when we consolidate VIEs for which we are the primary beneficiary is approximately equal to our recorded investment and will not result in recording a cumulative effect of an accounting change upon initial adoption of FIN 46. The maximum exposure to loss represents the loss that we would incur if our investment 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, 2002 consists of the following:

- our guarantee of $507 million of the High Desert lease and a portion of other committed expenses as discussed in *Note 10*,
- our recorded investment in these VIEs totaling $196 million, and
- guarantees of $27 million of the debt of these VIEs.

We assess the risk of a loss equal to our maximum exposure to be remote.

EITF 02-3

On October 25, 2002, the EITF reached a consensus on Issue 02-3, *Recognition and Reporting of Gains and Losses on Energy Trading Contracts Under EITF Issues No. 98-10 and No. 00-17*, that changed the accounting for certain energy contracts. The main provisions of EITF 02-3 are as follows:

EITF 02-3 prohibits the use of mark-to-market accounting for any energy-related contracts that are not derivatives. Any contracts subject to EITF 02-3 must be accounted for on the accrual basis and recorded in the income statement gross rather than net upon application of EITF 02-3. This change applied immediately to new contracts executed after October 25, 2002 and applied to existing non-derivative energy-related contracts beginning January 1, 2003.

We are required to report the impact of initially applying EITF 02-3 as the cumulative effect of a change in accounting principle effective January 1, 2003.

The EITF minutes on Issue 02-3 indicate that an entity should not record unrealized gains or losses at the inception of derivative contracts unless the fair value of the contracts is evidenced by observable market data.

Applying EITF 02-3 will not affect our cash flows or our accounting for new load-serving contracts for which we have been using accrual accounting since early 2002. Additionally, we continued to mark existing non-derivative energy-related contracts to market for the remainder of 2002. However, EITF 02-3 requires us to record a non-cash, cumulative effect adjustment to convert these non-derivative mark-to-market contracts to accrual accounting no later than January 1, 2003.

We reviewed our portfolio of mark-to-market contracts to identify the contracts that are subject to the requirements of EITF 02-3. The primary contracts that are affected are our full requirements load-serving contracts and unit-contingent power purchase contracts, which are not derivatives. The majority of these contracts are in Texas and New England and were entered into prior to the shift to accrual accounting earlier in 2002. Additionally, we reviewed derivatives we use as supply sources and hedges of contracts that are subject to EITF 02-3. To the extent permitted by SFAS No. 133, we designated derivative contracts used to fulfill our load-serving contracts as either normal purchases or cash flow hedges under SFAS No. 133 effective January 1, 2003.

We summarize the impact on our Consolidated Balance Sheets of applying EITF 02-3 on January 1, 2003 as follows:

	Assets	Liabilities	Net
		(In millions)	
Mark-to-market energy contracts			
Current	$ 144.0	$ 94.1	$ 49.9
Noncurrent	1,348.2	881.5	466.7
Total	1,492.2	975.6	516.6
Other			
Current	85.7	56.8	28.9
Noncurrent	24.2	2.5	21.7
Total	109.9	59.3	50.6
Balance at December 31, 2002	1,602.1	1,034.9	567.2
Impact of EITF 02-3 Adoption			
Non-derivative net asset reversed as cumulative effect of a change in accounting principle	(494.7)	(119.8)	(374.9)

	Assets	Liabilities	Net
Mark-to-market energy contracts			
Other	(109.9)	(59.3)	(50.6)
Total non-derivative net asset reversed as cumulative effect of a change in accounting principle	(604.6)	(179.1)	(425.5)
Derivatives designated as hedges	(88.3)	(94.4)	6.1
Derivatives designated as normal purchases and sales	(192.6)	(128.3)	(64.3)
Mark-to-market derivatives remaining after adoption of EITF 02-3 on January 1, 2003	$ 716.6	$ 633.1	$ 83.5

On January 1, 2003, we recorded the $425.5 million non-derivative net asset removed from our Consolidated Balance Sheets as a cumulative effect of a change in accounting principle, which will reduce our 2003 net income by $263 million. The $425.5 million represents $374.9 million of non-derivative contracts recorded as "Mark-to-market energy assets and liabilities" and $50.6 million of "Other assets and liabilities" from the re-designation of Texas contracts to accrual accounting earlier in 2002. The fair value of these contracts will be recognized in earnings as power is delivered.

Additionally, on January 1, 2003, we reclassified the fair value of derivatives designated as hedges as "Risk management assets and liabilities" in the balance sheet and will account for these hedges in accordance with the provisions of SFAS No. 133. At that time, we also reclassified the fair value of derivatives designated as normal purchases and normal sales as "Other assets and liabilities" in the balance sheet and will account for these contracts on the accrual basis, with the fair value amortized into earnings over the lives of the underlying contracts.

2 Impairment Losses, Workforce Reduction, Contract Termination, and Other Special Items

2002 Events

	Pre-Tax	After-Tax
	(In millions)	
Workforce reduction costs:		
Costs associated with 2001 programs	$ (50.8)	$ (30.8)
Costs associated with programs initiated in 2002	(12.0)	(7.2)
Total workforce reduction costs	(62.8)	(38.0)
Impairment losses and other costs:		
Impairments of investments in qualifying facilities and power projects	(14.4)	(9.9)
Costs associated with exit of BGE Home merchandise stores	(9.0)	(6.1)
Impairments of real estate and international investments	(1.8)	(1.2)

2002 Events

Total impairment losses and other costs	(25.2)	(17.2)
Net gain on sales of investments and other assets	261.3	166.7
Total special items	$ 173.3	$ 111.5

Workforce Reduction Costs

During 2002, we incurred costs related to workforce reduction efforts initiated in the fourth quarter of 2001 as discussed in this Note and additional initiatives undertaken in the third quarter of 2002. We discuss these costs in more detail below.

Costs associated with 2001 Programs

In 2002, we recorded $63.7 million of net workforce reduction costs associated with our 2001 workforce initiatives as discussed below. The $63.7 million included $50.8 million recognized as expense, of which BGE recognized $33.8 million. The remaining $12.9 million was recognized by BGE as a regulatory asset related to its gas business as discussed in *Note 5*.

We recorded $52.9 million when 308 employees elected the age 50 to 54 Voluntary Special Early Retirement Program (VSERP).

We reversed $17.8 million of the $25.1 million involuntary severance accrual that was recorded in 2001 to reflect the employees that elected the age 50 to 54 VSERP. Ultimately, we involuntarily severed 129 employees that resulted in a total cost for the involuntary severance program of $7.3 million.

We recorded $29.6 million of settlement charges related to our pension plans under SFAS No. 88, *Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits*. These charges reflect the recognition of actuarial gains and losses associated with employees who have retired and taken their pension in the form of a lump-sum payment. Under SFAS No. 88, the settlement charge could not be recognized until lump-sum pension payments exceeded annual pension plan service and interest cost, which occurred in 2002.

We recorded a $1.6 million expense associated with deferred payments to employees eligible for the VSERP.

Partially offsetting these costs, we reversed approximately $2.6 million of previously accrued workforce reduction costs primarily as a result of the reversal of education and outplacement assistance benefits we accrued that employees did not utilize to the extent expected.

In 2002, we completed the 2001 workforce reduction programs. Accordingly, no involuntary severance liability recorded under EITF 94-3, *Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)* remained at December 31, 2002.

Costs associated with 2002 Programs

In 2002, we recorded $12.0 million of expenses for anticipated involuntary severance costs in accordance with EITF 94-3 associated with new workforce reduction initiatives as follows:

We recorded $8.5 million for workforce reduction costs for the severance of 120 employees at Calvert Cliffs Nuclear Power Plant (Calvert Cliffs).

We recorded $1.6 million of workforce reduction costs for the severance of 27 employees in our information technology organization. BGE recorded $0.6 million of this amount.

We recorded $1.9 million of workforce reduction costs for the severance of 20 employees in our legal organization. BGE recorded $0.9 million of this amount.

At December 31, 2002, the involuntary severance liability recorded under EITF 94-3 for our 2002 workforce reduction programs was $12.0 million.

Impairment Losses and Other Costs

Investments in Qualifying Facilities and Power Projects

In the third quarter of 2002, our merchant energy business recorded impairment losses on certain of the investments in qualifying facilities and power projects totaling $14.4 million under the provisions of APB No. 18. We describe these investments in *Note 4*. The provisions of APB No. 18 require that an impairment loss be recognized when an investment experiences a loss in value that is other than temporary as discussed in *Note 1*.

During the third quarter of 2002, we performed an analysis of whether any of the investments were impaired. As a result of our analysis, we concluded that the declines in value of particular investments in certain qualifying facilities and power projects were other than temporary in nature under the provisions of APB No. 18 and we recognized the following losses in 2002:

We recognized a $5.2 million other than temporary decline in value of our investment in a partnership that owns a geothermal project in Nevada. This project experienced a well implosion and we believe that the expected cash flows from the project will not be sufficient to recover our equity interest in that partnership.

We recognized a $2.6 million other than temporary decline in value of our investment in a fuel processing site in Pennsylvania where the expected cash flows from a sublease are no longer expected to be sufficient to recover our lease costs associated with this site.

We recognized a $6.6 million other than temporary decline in value of our investment in a partnership that owns a waste burning power project in Michigan. In 2001, we recognized a $6.1 million pre-tax impairment loss on this investment because we expected operating cash flows would not be sufficient to pay existing debt service and that we would not be able to recover our equity investment. However, at that time, we believed that we would recover our senior working capital loans receivable and accounts receivable for operating the project. As of the third quarter of 2002, the operating performance of the project did not improve as expected, and we believed the expected future cash flows were no longer sufficient to recover these receivables. Therefore, we recognized an additional impairment loss on this investment.

Closing of BGE Home Retail Merchandise Stores

In September 2002, we announced our decision to close our BGE Home retail merchandise stores. In connection with that decision, we recognized approximately $9.5 million in exit costs. We recognized $2.9 million related to expected severance costs for 93 employees and $2.9 million of costs in connection with the termination of leases for the eight stores and other exit costs in accordance with EITF 94-3.

We also recognized $3.2 million for the write-off of unamortized leasehold improvements in accordance with SFAS No. 144, and $0.5 million for the write-down of inventory to a lower-of-cost-or-market valuation in accordance with Accounting Research Bulletin No. 43, *Restatement and Revision of Accounting Research Bulletins*. The $0.5 million is included in "Operating expenses" in our Consolidated Statements of Income.

Real Estate and International Investments

As discussed in the *2001 Events* section on the next page, we changed our strategy from an intent to hold to an intent to sell for certain of our non-core assets in 2001. During 2002, we determined that the fair value of several real estate projects and our investment in a South American generation project declined below their respective book values due to deteriorating market conditions for these projects. Accordingly, we recorded losses that totaled $1.8 million for these projects in accordance with SFAS No. 144 and APB No. 18.

Net Gain on Sales of Investments and Other Assets

In February 2002, Reliant Resources, Inc. acquired all of the outstanding shares of Orion Power Holdings, Inc. (Orion) for $26.80 per share, including the shares we owned of Orion. We received cash proceeds of $454.1 million and recognized a gain of $255.5 million on the sale of our investment.

In the fourth quarter of 2001, we announced our decision to focus efforts and capital on core domestic energy businesses and undertook a plan to sell a number of non-core businesses and investments. In 2002, we made further progress on this initiative, and recognized approximately $5.8 million in net gains from the sale of several non-core assets including:

Our other nonregulated businesses recognized gains totaling $6.7 million on the sale of several parcels of real estate and financial investments.

In October 2002, we sold all of our 18 senior-living facilities for $77.2 million that represents a combination of cash and the assumption by the buyer of existing mortgages. Our other nonregulated businesses recognized a $2.8 million gain on the sale of our entire ownership interest in these facilities.

Our merchant energy business recognized a $2.3 million gain on the sale of a discontinued wind-powered development project.

In 2001, our merchant energy business recognized an impairment loss on four turbines, associated with a discontinued development program as discussed in the *2001 Events* section. Since that time, many other companies canceled development projects and the market values for turbines have declined significantly. Orders for three of the four turbines were canceled with termination fees paid to the manufacturer consistent with the amount recognized in December 2001. The fourth turbine-generator set was sold during 2002 for $6.0 million below its book value.

2001 Events

	Pre-Tax	After-Tax
	(In millions)	
Workforce reduction costs:		
Voluntary termination benefits VSERP	$ (70.1)	$ (42.5)
Settlement and curtailment charges	(16.3)	(9.9)
Involuntary severance accrual	(19.3)	(11.7)
Total workforce reduction costs	(105.7)	(64.1)
Contract termination related costs	(224.8)	(139.6)
Impairment losses and other costs:		
Cancellation of domestic power projects	(46.9)	(30.5)
Impairments of real estate, senior-living and international investments	(107.3)	(69.7)
Reduction of financial investment	(4.6)	(2.8)
Total impairment losses and other costs	(158.8)	(103.0)
Net gain on the sales of investments and other assets	6.2	1.9

	Pre-Tax	After-Tax
Total special items	$ (483.1)	$ (304.8)

Workforce Reduction Costs

Voluntary Special Early Retirement Programs VSERP

In the fourth quarter of 2001, we undertook several measures to reduce our workforce through both voluntary and involuntary means. The purpose of these programs was to reduce our operating costs to become more competitive. We offered several workforce reduction programs to employees of Constellation Energy and certain subsidiaries. The first group of these programs offered enhanced early retirement benefits to employees age 55 or older with 10 or more years of service. The second group of these programs offered enhanced early retirement benefits to employees age 50 to 54 with 20 or more years of service.

Since employees electing to participate in the age 55 or older VSERP had to make their elections by the end of 2001, the cost of that program was reflected in 2001. The $70.1 million in the above table reflects the portion of the total cost of that program charged to expense for the 507 employees that elected to participate. BGE recorded $37.9 million of this amount. BGE also recorded $13.7 million on its balance sheet as a regulatory asset related to its gas business as discussed in *Note 5*.

Settlement and Curtailment Charges

In connection with the age 55 or older VSERP, a significant number of the participants in our nonqualified pension plans retired. As a result, we recognized a settlement loss of approximately $10.5 million and a curtailment loss of approximately $5.8 million for those plans in accordance with SFAS No. 88. BGE recorded $6.6 million of this amount. Additional details on the VSERP and their impact on our pension and postretirement benefit plans are discussed in *Note 6*.

Involuntary Severance Accrual

The voluntary programs were designed, offered, and timed to minimize the number of employees who would be involuntarily severed under our overall workforce reduction plan. Our workforce reduction plan identified 435 jobs to be eliminated over and above position reductions expected to be satisfied through the age 55 or older VSERP and was specific as to company, organizational unit, and position. However, the number of employees that would elect to voluntarily retire under the age 50 to 54 VSERP and how many would thereafter be involuntarily severed was not known until after the election period of the VSERP ended in February 2002.

In accordance with EITF 94-3, the Company recognized a liability of $25.1 million at December 31, 2001 for the targeted number of involuntary terminations that would have resulted if no employees elected the age 50 to 54 VSERP. The $19.3 million in the table above represents involuntary severance charged to expense in 2001 in connection with our workforce reduction programs. BGE recorded $12.5 million of this amount. BGE also recorded $5.8 million on its balance sheet as a regulatory asset related to its gas business as discussed in *Note 5*.

Contract Termination Related Costs

On October 26, 2001, we announced the decision to remain a single company and canceled prior plans to separate our merchant energy business from our remaining businesses.

We also announced the termination of our power business services agreement with Goldman Sachs. We paid Goldman Sachs a total of $355 million, representing $196.7 million to terminate the power business services agreement with our origination and risk management operation and $159 million previously recognized as a payable for services rendered under the agreement.

In addition, we terminated a software agreement we had whereby Goldman Sachs would provide maintenance, support, and minor upgrades to our risk management and trading system. We recognized $17.6 million in expense in the fourth quarter of 2001 representing the unamortized prepaid costs related to this agreement. Finally, we incurred approximately $10.5 million in employee-related expenses and advisory costs from investment bankers and legal counsel. In total, we recognized expenses of approximately $224.8 million in the fourth quarter of 2001 relating to the termination of our relationship with Goldman Sachs and our decision not to separate.

Impairment Losses and Other Costs

Cancellation of Domestic Power Projects

In the fourth quarter of 2001, our merchant energy business recorded impairments of $46.9 million primarily due to $40.8 million in impairments associated with the termination of our planned development projects in Texas, California, Florida, and Massachusetts not under construction. We decided to terminate our development projects due to the expected excess generation capacity in most domestic markets and the significant decline in the forward market prices of electricity. The impairments include amounts paid for the purchase of four turbines related to these development projects. In addition, we recognized $6.1 million for an other than temporary decline in the value of our investment in a waste burning power plant in Michigan where operating cash flows are not sufficient to pay existing debt service and we are not likely to recover our equity interest in this investment.

Impairments of Real Estate, Senior-Living, and Other International Investments

In the fourth quarter of 2001, our other nonregulated businesses recorded $107.3 million in impairments of certain real estate projects, senior-living facilities, and international assets to reflect the fair value of these investments. These investments represent non-core assets with a book value of approximately $140.6 million after these impairments. As part of our focus on capital and cash requirements and on our core energy businesses, the following occurred:

- We decided to sell six real estate projects without further development and all of our 18 senior-living facilities in 2002 and accelerate the exit strategies for two other real estate projects that we will continue to hold and own over the next several years. The real estate projects include approximately 1,300 acres of land holdings in various stages of development located in seven sites in the central Maryland region and an operating waste water treatment plant located in Anne Arundel County, Maryland. In 2002, we sold approximately 800 acres of land holdings.

- We decided to accelerate the exit strategy for our interest in a Panamanian electric distribution company. As a non-core asset, management has decided to reduce the cost and risk of holding this asset indefinitely and intends to dispose of this asset.

- We incurred an other than temporary decline in our equity-method investment in the Bolivian Generating Group, which owns an interest in an electric generation concession in Bolivia. This decline in value resulted from a deterioration of our investment's position in the dispatch curve of its capacity market. As a result, we recorded the impairment in accordance with the provisions of Accounting Principles Board Opinion No. 18.

The impairments of our real estate, senior-living facilities, and Panama investments resulted from our change from an intent to hold to an intent to sell certain of these non-core assets in 2002, and our decision to limit future costs and risks by accelerating the exit strategies for certain assets that cannot be sold by the end of 2002. Previously, our strategy for these investments was to hold them until we could obtain reasonable value. Under that strategy, the expected cash flows were greater than our investment and no impairment was recognized.

Reduction of Financial Investment

Our financial investments operation recorded a $4.6 million reduction of its investment in a leased aircraft due to the other than temporary decline in the estimated residual value of used airplanes as a result of the September 11, 2001 terrorist attacks and the general downturn in the aviation industry. This investment is accounted for as a leveraged lease under SFAS No. 13, *Accounting for Leases.*

Net Gain on Sales of Investments and Other Assets

During 2001, our other nonregulated businesses recognized $49.5 million on the sale of non-core assets, including a $14.9 million gain on the sale of one million shares of our Orion investment and $34.6 million on the sales of other financial investments.

In addition, in 2001, we sold our Guatemalan power plant operations to an affiliate of Duke Energy International, LLC, the international business unit of Duke Energy. Through this sale, Duke Energy acquired Grupo Generador de Guatemala y Cia., S.C.A., which owns two generating plants at Esquintla and Lake Amatitlan in Guatemala. The combined capacity of the plants is 167 megawatts.

We decided to sell our Guatemalan operations to focus our efforts on our core energy businesses. As a result of this transaction, we are no longer committed to making significant future capital investments in a non-core operation. We recorded a $43.3 million loss on this sale.

2000 Events

In 2000, BGE offered a targeted VSERP to employees ages 55 or older with 10 or more years of service in targeted positions that elected to retire on June 1, 2000 to reduce our operating costs to become more competitive. BGE recorded approximately $10.0 million pre-tax for employees that elected to participate in the program. Of this amount, BGE recorded approximately $3.0 million on its balance sheet as a regulatory asset of its gas business. BGE is amortizing this regulatory asset over a 5-year period as provided by the June 2000 Maryland PSC gas base rate order as discussed in *Note 5*. The remaining $7.0 million, or $4.2 million after-tax, related to BGE's electric business and was charged to expense.

In addition, we recognized $78.1 million pre-tax, or $47.2 million after-tax, gains including $15.7 million pre-tax, or $9.5 million after-tax, on the sale of two million shares of our Orion investment and $62.4 million pre-tax, or $37.7 million after-tax, on the sales of other financial investments.

3 Information by Operating Segment

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

- Our nonregulated merchant energy business in North America includes:
  - fossil, nuclear, and hydroelectric generating facilities and interests in qualifying facilities and power projects in the United States,
  - origination of structured transactions (such as load-serving, tolling contracts, and power purchase agreements), and risk management services (hedging of output from generating facilities and fuel costs),
  - electric and gas retail energy services to large commercial and industrial customers, and
  - generation and consulting services.
- Our regulated electric business purchases, transmits, distributes, and sells electricity in Maryland.
- Our regulated gas business purchases, transports, and sells natural gas in Maryland.

Effective July 1, 2000, the financial results of the electric generation portion of our business are included in the merchant energy business segment. Prior to that date, the financial results of electric generation are included in our regulated electric business.

- Our remaining nonregulated businesses:
  - design, construct, and operate single-site heating, cooling, and cogeneration facilities for commercial and industrial customers,
  - service electric and gas appliances, and heating and air conditioning systems, engage in home improvements, and sell electricity and natural gas, and
  - own and operate a district cooling system for commercial customers.

In addition, we own several investments that we do not consider to be core operations. These include financial investments, real estate projects, and interests in a Latin American power distribution project and in a fund that holds interests in two South American energy projects. We decided to sell certain non-core assets and accelerated the exit strategies of other projects. We sold certain non-core assets in 2002 and closed our retail merchandise stores in December 2002.

These 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.

We have reclassified certain prior-year information for comparative purposes based on our reportable operating segments.

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	Merchant Energy Business	Regulated Electric Business	Regulated Gas Business	Other Nonregulated Businesses	Unallocated Corporate Items and Eliminations	Consolidated
			(In millions)			
2002						
Unaffiliated revenues	**$ 1,629.5**	**$ 1,965.6**	**$ 570.5**	**$ 537.4**	**$**	**$ 4,703.0**
Intersegment revenues	**1,136.2**	**0.4**	**10.8**		**(1,147.4)**	
Total revenues	**2,765.7**	**1,966.0**	**581.3**	**537.4**	**(1,147.4)**	**4,703.0**
Depreciation and amortization	**242.8**	**174.2**	**47.4**	**16.6**		**481.0**
Fixed charges	**102.0**	**128.4**	**25.9**	**25.2**		**281.5**
Income tax expense	**127.2**	**67.1**	**22.4**	**92.9**		**309.6**
Net income (a)	**247.2**	**99.3**	**31.1**	**148.0**		**525.6**
Segment assets	**8,866.0**	**3,565.1**	**1,140.4**	**913.0**	**(355.6)**	**14,128.9**
Capital expenditures	**641.0**	**167.0**	**50.0**	**65.0**		**923.0**
2001						
Unaffiliated revenues	$ 614.3	$ 2,039.6	$ 674.3	$ 550.6	$	$ 3,878.8
Intersegment revenues	1,151.2	0.4	6.4	2.0	(1,160.0)	
Total revenues	1,765.5	2,040.0	680.7	552.6	(1,160.0)	3,878.8
Depreciation and amortization	174.9	173.3	47.7	23.2		419.1
Fixed charges	25.8	135.8	28.5	48.7		238.8
Income tax expense (benefit)	25.2	36.8	25.7	(49.8)		37.9
Cumulative effect of change in accounting principle				8.5		8.5
Net income (loss) (b)	93.1	50.9	37.5	(90.6)		90.9
Segment assets	8,123.9	3,764.9	1,104.2	1,314.0	(197.6)	14,109.4
Capital expenditures	1,044.0	180.3	58.7	35.0		1,318.0
2000						
Unaffiliated revenues	$ 421.1	$ 2,134.7	$ 603.8	$ 614.8	$	$ 3,774.4
Intersegment revenues	604.6	0.5	7.8	20.4	(633.3)	
Total revenues	1,025.7	2,135.2	611.6	635.2	(633.3)	3,774.4
Depreciation and amortization	83.6	319.9	46.2	20.3		470.0
Equity in income of equity-method investees (c)		2.4				2.4
Fixed charges	18.3	168.4	27.3	65.8	(8.4)	271.4
Income tax expense	118.5	72.2	21.9	17.5		230.1
Net income (d)	198.6	102.3	30.6	13.8		345.3
Segment assets	7,295.5	3,392.3	1,089.9	1,491.5	(329.9)	12,939.3
Capital expenditures	699.0	290.3	59.7	131.5		1,180.5

(a)
Our merchant energy business, our regulated electric business, our regulated gas business, and our other nonregulated businesses recognized after-tax charges (income) of $28.3 million, $20.5 million, $0.8 million, and ($161.1 million), respectively, for workforce reduction costs, business exit costs, impairment losses and other costs, and net gains on sales of investments and other assets as

described in more detail in Note 2.

(b) *Our merchant energy business, our regulated electric business, our regulated gas business, and our other nonregulated businesses recognized after-tax charges of $198.1 million, $33.6 million, $0.8 million, and $72.3 million, respectively, for workforce reduction costs, contract termination related costs, impairment losses and other costs, and a net gain on sales of investments and other assets as described more fully in Note 2.*

(c) *Our merchant energy business records its equity in the income of equity-method investees in unaffiliated revenues.*

(d) *Our regulated electric business recorded an after-tax charge of $4.2 million related to employees that elected to participate in a Voluntary Special Early Retirement Program. In addition, our merchant energy business recorded a $15.0 million after-tax deregulation transition cost incurred by our origination and risk management operation. Our other nonregulated businesses also recorded a net gain of $47.2 million on sales of investments and other assets.*

4 Investments

Real Estate Projects and Investments

Real estate projects and investments consist of the following:

At December 31,	2002	2001
	(In millions)	
Operating properties and properties under development	**$ 77.8**	$ 101.4
Equity interest in real estate investments	**8.3**	109.3
Total real estate projects and investments	**$ 86.1**	$ 210.7

In March 2002, we sold all of our Corporate Office Properties Trust equity-method investment, approximately 8.9 million shares, as part of a public offering. We received cash proceeds of $101.3 million on the sale, which approximated the book value of our investment.

See *Note 2* for a discussion of impairments recorded in 2002 and 2001.

Investments in Qualifying Facilities and Power Projects

Our merchant energy business holds up to a 50% ownership interest in 28 operating domestic energy projects that consist of electric generation, fuel processing, or fuel handling facilities. Of these 28 projects, 20 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,	2002	2001
	(In millions)	

At December 31,

	2002	2001
Geothermal	**$ 151.4**	$ 162.0
Coal	**133.9**	160.4
Hydroelectric	**62.6**	62.3
Biomass	**52.6**	59.4
Fuel Processing	**23.2**	33.6
Solar	**10.5**	10.7
Waste to Energy		2.6
Total	**$ 434.2**	$ 491.0

The investment in qualifying facilities and domestic power projects were accounted for under the following methods:

At December 31,

	2002	2001
	(In millions)	
Equity Method	**$ 423.7**	$ 480.3
Cost Method	**10.5**	10.7
Total power projects	**$ 434.2**	$ 491.0

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 were $9.1 million in 2002, $23.1 million in 2001, and $50.2 million in 2000.

Our power projects accounted for under the equity method include investments of $260.6 million in 2002 and $296.4 million in 2001 that sell electricity in California under power purchase agreements called "Interim Standard Offer No. 4" agreements. We discuss these projects further in *Note 11*.

Our other nonregulated businesses also held international energy projects accounted for under the equity method of $5.0 million at December 31, 2002 and $8.1 million at December 31, 2001.

See *Note 2* for a discussion of impairments recorded in 2002 and 2001.

Orion and Financial Investments

Financial investments consist of the following:

At December 31,

	2002	2001
	(In millions)	
Orion	**$**	$ 442.5
Marketable equity securities		20.2
Financial limited partnerships	**24.2**	25.8
Leveraged leases	**12.7**	14.7
Total financial investments	**$ 36.9**	$ 503.2

We discuss the sale of our investment in Orion in *Note 2*.

Investments Classified as Available-for-Sale

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

nuclear decommissioning trust funds,

our other nonregulated businesses' marketable equity securities (shown above), 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 bases 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, except we used the average cost basis for our investment in Orion.

At December 31, 2002	Amortized Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value
	(In millions)			
Marketable equity securities	**$ 642.6**	**$ 18.9**	**$ (69.2)**	**$ 592.3**
Corporate debt and U.S. Government agency	**51.5**	**1.7**	**(0.1)**	**53.1**
State municipal bonds	**22.0**	**1.3**		**23.3**
Totals	**$ 716.1**	**$ 21.9**	**$ (69.3)**	**$ 668.7**

At December 31, 2001	Amortized Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value
	(In millions)			
Marketable equity securities	$ 816.1	$ 270.6	$ (10.3)	$ 1,076.4
Corporate debt and U.S. Government agency	47.7	1.5		49.2
State municipal bonds	38.4	3.3	(0.2)	41.5
Totals	$ 902.2	$ 275.4	$ (10.5)	$ 1,167.1

In addition to the above securities, the nuclear decommissioning trust funds included $14.0 million at December 31, 2002 and $7.7 million at December 31, 2001 of cash and cash equivalents.

The preceding tables include $47.4 million in 2002 of net unrealized losses and $21.0 million in 2001 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.

Gross and net realized gains and losses on available-for-sale securities, excluding the gains on our sales of the Orion investment, were as follows:

	2002	2001	2000
	(In millions)		

	2002	2001	2000
Gross realized gains	**$ 6.0**	$ 47.6	$ 54.5
Gross realized losses	**(9.5)**	(7.9)	(8.0)
Net realized (losses) gains	**$ (3.5)**	$ 39.7	$ 46.5

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

At December 31, 2002

	Amount
	(In millions)
Less than 1 year	$ 5.4
1-5 years	30.7
5-10 years	22.1
More than 10 years	18.2
Total maturities of debt securities	$ 76.4

5 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 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 utility 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,

	2002	2001
	(In millions)	
Electric generation-related regulatory asset	**$ 230.1**	$ 249.0
Income taxes recoverable through future rates (net)	**88.8**	95.6
Deferred postretirement and postemployment benefit costs	**32.3**	35.5
Deferred environmental costs	**23.2**	26.0
Deferred fuel costs (net)	**1.9**	33.5
Workforce reduction costs	**28.2**	21.6
Other (net)	**1.2**	2.6
Total regulatory assets (net)	**$ 405.7**	$ 463.8

Electric Generation-Related Regulatory Asset

As a result of the deregulation of electric generation, BGE no longer met the requirements for the application of SFAS No. 71 for the electric generation portion of its business. In accordance with SFAS No. 101 and EITF 97-4, 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.

A portion of this regulatory asset represents the decommissioning and decontamination fund payment for federal uranium enrichment facilities that does not earn a return on the rate base investment. These amounts were $16.3 million at December 31, 2002 and $19.2 million at December 31, 2001. Prior to the deregulation of electric generation, these costs were recovered through the electric fuel rate mechanism, and were excluded from rate base. We will continue to amortize this amount through 2008.

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 utility 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 (for postretirement benefits) and No. 112 (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. We discuss these costs further in *Note 6*.

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 11*. We are amortizing $21.6 million of these costs (the amount we had incurred through October 1995) and $6.4 million of these costs (the amount we incurred from November 1995 through June 2000) over 10-year periods in accordance with the Maryland PSC's orders.

Deferred Fuel Costs

As described in *Note 1*, deferred fuel costs are the difference between our actual costs of natural gas and our fuel rate revenues collected from customers. We reduce deferred fuel costs as we collect them from or refund them to our customers.

In December 2002, a Hearing Examiner from the Maryland PSC issued a proposed order related to our annual gas adjustment clause review proceeding that will allow us to recover $1.7 million of a previously established regulatory asset of $9.4 million for certain credits that were over-refunded to customers through our market-based rates. BGE reserved the remaining difference of $7.7 million as disallowed fuel costs. However, we appealed the proposed order. As of the date of this report, the Maryland PSC has not acted on BGE's appeal.

Our gas deferred fuel costs were $1.9 million at December 31, 2002 and $33.5 million at December 31, 2001.

We exclude gas deferred fuel costs from rate base because their existence is relatively short-lived. These costs are recovered in the following year through the market-based rate mechanism.

Workforce Reduction Costs

The portions of the costs associated with the VSERP and workforce reduction programs we announced that relate to BGE's gas business are deferred as regulatory assets in accordance with the Maryland PSC's orders in prior rate cases. These costs are amortized over 5-year periods. See *Note 2* and *Note 6*.

6 Pension, Postretirement, Other Postemployment, and Employee Savings Plan Benefits

We offer pension, postretirement, other postemployment, and employee savings plan benefits. We describe each of these 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.

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 plans by contributing at least the minimum amount required under Internal Revenue Service 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, 2002 were mostly marketable equity and fixed income securities.

Postretirement Benefits

We sponsor defined benefit postretirement health care and life insurance plans that cover substantially all of our employees. Generally, we calculate the benefits under these plans based on age, years of service, and pension benefit levels. 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 January 1, 1993, we adopted SFAS No. 106, *Employers' Accounting for Postretirement Benefits Other Than Pension*s. The adoption of that statement caused:

- a transition obligation, which we are amortizing over 20 years, and
- an increase in annual postretirement benefit costs.

For our regulated utility business, we accounted for the increase in annual postretirement benefit costs under two Maryland PSC rate orders:

- in an April 1993 rate order, the Maryland PSC allowed us to expense one-half and defer, as a regulatory asset (see *Note 5*), the other half of the increase in annual postretirement benefit costs related to our regulated electric and gas businesses, and
- in a November 1995 rate order, the Maryland PSC allowed us to expense all of the increase in annual postretirement benefit costs related to our regulated gas business.

Beginning in 1998, the Maryland PSC authorized us to:

expense all of the increase in annual postretirement benefit costs related to our regulated electric business, and

amortize the regulatory asset for postretirement benefit costs related to our regulated electric and gas businesses over 15 years.

Effective in 2002, we amended our postretirement medical plans for all affiliates 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.

VSERP

In 2000, we offered a targeted VSERP to provide enhanced early retirement benefits to certain eligible participants in targeted jobs at BGE that elected to retire on June 1, 2000. BGE recorded approximately $10.0 million ($7.6 million for pension termination benefits and $2.4 million for postretirement benefit costs) for employees that elected to participate in the program. Of this amount, BGE recorded approximately $3.0 million on its balance sheet as a regulatory asset of its gas business. We amortize this regulatory asset over a 5-year period as provided for in prior Maryland PSC rate orders. The remaining $7.0 million related to BGE's electric business was charged to expense.

In 2001, our Board of Directors approved several voluntary retirement programs for Constellation Energy and certain subsidiaries. The first group of these programs offered enhanced early retirement benefits to employees age 55 or older with 10 or more years of service. The second group of these programs offered enhanced early retirement benefits to employees age 50 to 54 with 20 or more years of service.

Since employees electing to participate in the age 55 or older VSERP had to make their elections by the end of 2001, the cost of that program was reflected in 2001. The total cost of that program was approximately $83.8 million ($63.5 million in pension termination benefits, $18.5 million in postretirement benefit costs, and $1.8 million in education and outplacement assistance costs). Of this amount, BGE recorded approximately $13.7 million on its balance sheet as a regulatory asset of its gas business.

The age 50 to 54 program allowed employees to make their elections beginning in 2002. The cost of that program was approximately $52.9 million ($43.0 million in pension termination costs, $8.5 million in postretirement benefit costs, and $1.4 million in education and outplacement assistance costs). Of this amount, BGE recorded approximately $13.4 million on its balance sheet as a regulatory asset of its gas business. We incurred approximately $0.7 million of postretirement benefit costs related to additional workforce reduction initiatives in 2002.

In connection with the retirement of a significant number of the participants in the nonqualified pension plans we recognized a settlement loss of approximately $10.5 million and a curtailment loss of approximately $5.8 million for those plans in accordance with SFAS No. 88 in 2001. We recorded additional settlement charges of $29.6 million related to our qualified and nonqualified pension plans in 2002 as a result of retirees electing to take their pension benefit in the form of a lump-sum payment.

At December 31, 2002, our pension obligations were greater than the fair value of our plan assets for our qualified and our nonqualified pension plans as follows:

	Qualified Plans			
	Nine Mile	**Other**	**Non-Qualified Plans**	**Total**
		(In millions)		
Accumulated benefit obligation	$ 85.7	$ 981.6	$ 35.0	$ 1,102.3
Fair value of assets	57.8	709.9		767.7
Unfunded obligation	$ 27.9	$ 271.7	$ 35.0	$ 334.6

Qualified Plans

In 2001, we recorded a $133.0 million additional minimum pension liability adjustment primarily as a result of decreases in the fair value of plan assets due to a declining equity market that year. We recorded $59.0 million of this adjustment to an intangible asset included in "Other deferred charges" in our Consolidated Balance Sheets. We included the remaining $74.0 million, or $44.7 million after-tax, of this adjustment in "Accumulated other comprehensive income" in our Consolidated Statements of Common Shareholders' Equity and Consolidated Statements of Capitalization.

In 2002, we recorded an additional minimum pension liability of $189.5 million as a result of the decreases in the fair value of plan assets due to continued declines in the equity markets. We recorded $5.8 million of this adjustment as a reduction to an intangible asset. We included the remaining $195.3 million, or $118.1 million after-tax, of this adjustment in "Accumulated other comprehensive income."

The cost of the voluntary retirement programs and the settlement and curtailment losses are not included in the tables of net periodic pension and postretirement benefit costs for the respective years.

Obligations, Assets, and Funded Status

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	
	2002	**2001**	**2002**	**2001**
	(In millions)			
Change in benefit obligation				
Benefit obligation at January 1	**$ 1,259.2**	$ 1,045.1	**$ 475.2**	$ 375.9
Service cost	**29.6**	25.8	**5.0**	8.4
Interest cost	**82.2**	76.1	**26.7**	29.2
Plan participants' contributions			**4.7**	3.0
Actuarial loss	**78.9**	42.6	**34.9**	49.1
Plan amendments			**(110.3)**	
VSERP charge	**43.0**	63.5	**9.2**	18.5
Curtailment		9.7		
Settlement	**(37.9)**	(23.0)		
Nine Mile Point acquisition		91.8		15.0
Benefits paid	**(207.5)**	(72.4)	**(30.0)**	(23.9)
Benefit obligation at December 31	**$ 1,247.5**	$ 1,259.2	**$ 415.4**	$ 475.2

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	Pension Benefits		Postretirement Benefits	
	2002	**2001**	**2002**	**2001**
	(In millions)			
Change in plan assets				
	$ 912.2	$ 1,004.6	**$**	$

	Pension Benefits		Postretirement Benefits	
Fair value of plan assets at January 1				
Actual return on plan assets	**(89.4)**	(42.7)		
Employer contribution	**152.4**	22.7	**25.3**	20.9
Plan participants' contributions			**4.7**	3.0
Benefits paid	**(207.5)**	(72.4)	**(30.0)**	(23.9)
Fair value of plan assets at December 31	**$ 767.7**	$ 912.2	**$**	$

	Pension Benefits		Postretirement Benefits	
	2002	**2001**	**2002**	**2001**
		(In millions)		
Funded Status				
Funded Status at December 31	**$ (479.8)**	$ (347.0)	**$ (415.4)**	$ (475.2)
Unrecognized net actuarial loss	**417.8**	207.8	**135.5**	107.8
Unrecognized prior service cost	**49.9**	56.7	**(43.8)**	(0.4)
Unrecognized transition obligation			**21.3**	86.9
Pension liability adjustment	**(322.5)**	(133.0)		
Accrued benefit cost	**$ (334.6)**	$ (215.5)	**$ (302.4)**	$ (280.9)

Net Periodic Benefit Cost

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

Year Ended December 31,	**2002**	**2001**	**2000**
		(In millions)	
Components of net periodic pension benefit cost			
Service cost	**$ 29.6**	$ 25.8	$ 25.4
Interest cost	**82.2**	76.1	73.1
Expected return on plan assets	**(91.0)**	(87.5)	(83.6)
Amortization of transition obligation		(0.2)	(0.2)
Amortization of prior service cost	**6.7**	6.5	6.5
Recognized net actuarial loss	**1.3**	2.8	2.6
Amount capitalized as construction cost	**(2.9)**	(2.5)	(3.4)

Year Ended December 31,	2002	2001	2000
Net periodic pension benefit cost	**$ 25.9**	$ 21.0	$ 20.4

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

Year Ended December 31,	2002	2001	2000
		(In millions)	
Components of net periodic postretirement benefit cost			
Service cost	**$ 5.0**	$ 8.4	$ 7.7
Interest cost	**26.7**	29.2	26.6
Amortization of transition obligation	**2.1**	7.9	7.9
Recognized net actuarial loss	**6.4**	3.3	3.1
Amortization of unrecognized prior service cost	**(3.5)**		
Amount capitalized as construction cost	**(9.1)**	(14.5)	(10.8)
Net periodic postretirement benefit cost	**$ 27.6**	$ 34.3	$ 34.5

Assumptions

We made the assumptions below to calculate our pension and postretirement benefit obligations.

At December 31,	Pension Benefits		Postretirement Benefits	
	2002	2001	2002	2001
Discount rate	**6.75%**	7.25%	**6.75%**	7.25%
Expected return on plan assets	**9.00**	9.00	**N/A**	N/A
Rate of compensation increase	**4.00**	4.00	**4.00**	4.00

We assumed the health care inflation rates to be:

in 2002, 11.6% for Medicare-eligible retirees and 14.4% for retirees not covered by Medicare, and

in 2003, 11.0% for both Medicare-eligible retirees and retirees not covered by Medicare.

After 2003, we assumed inflation rates will decrease to 8.0% in 2004, 6.0% in 2005, 5.5% from 2006 through 2008 and 5.0% annually after 2008.

A one-percent increase in the health care inflation rate from the assumed rates would increase the accumulated postretirement benefit obligation by approximately $34.3 million as of December 31, 2002 and would increase the combined service and interest costs of the postretirement benefit cost by approximately $2.6 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 $29.0 million as of December 31, 2002 and would decrease the combined service and interest costs of the postretirement benefit cost by approximately $2.2 million annually.

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 $49.7 million as of December 31, 2002 and $48.7 million as of December 31, 2001.

Effective December 31, 1993, we adopted SFAS No. 112, *Employers' Accounting for Postemployment Benefit*s. We deferred, as a regulatory asset (see *Note 5*), the postemployment benefit liability attributable to our regulated utility business as of December 31, 1993, consistent with the Maryland PSC's orders for postretirement benefits (described earlier in this Note).

We began to amortize the regulatory asset over 15 years beginning in 1998. The Maryland PSC authorized us to reflect this change in our regulated electric and gas base rates to recover the higher costs in 1998.

We assumed the discount rate for other postemployment benefits to be 5.75% in 2002 and 5.0% in 2001.

Employee Savings Plan Benefits

We, along with several of our subsidiaries, sponsor defined contribution savings plans that are offered to all eligible employees of Constellation Energy and certain employees of our subsidiaries. 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:

- $13.3 million in 2002,
- $12.2 million in 2001, and
- $10.8 million in 2000.

7 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 three credit facilities of $1.5 billion at December 31, 2002 for short-term financial needs as follows:

- $640 million 364-day revolving credit facility expiring in June 2003,
- $640 million three-year revolving credit facility expiring in June 2005, and
- $188.5 million revolving credit facility expiring in June 2003.

We use these facilities to allow issuance of commercial paper and letters of credit primarily for our merchant energy business. These facilities can issue letters of credit up to approximately $1.1 billion. Letters of credit issued under all of our facilities totaled $338.7 million at December 31, 2002 and $245.8 million at December 31, 2001. Constellation Energy had no commercial paper outstanding at December 31, 2002 and $954.9 million at December 31, 2001.

The weighted-average effective interest rates for Constellation Energy's commercial paper were 2.37% for the year ended December 31, 2002 and 3.73% for 2001.

BGE

BGE had no commercial paper outstanding at December 31, 2002 and 2001.

BGE maintains $200.0 million in annual committed credit facilities, expiring May through November of 2003, in order to allow commercial paper to be issued. At December 31, 2002, BGE had $200.0 million in unused credit facilities.

Other Nonregulated Businesses

Our other nonregulated businesses had short-term borrowings outstanding of $10.5 million at December 31, 2002 and $20.1 million at December 31, 2001. The weighted-average effective interest rates for our other nonregulated businesses' short-term borrowings were 3.61% at December 31, 2002 and 4.20% for 2001.

8 Long-Term Debt and Preference Stock

Long-term Debt

Long-term debt matures in one year or more from the date of issuance. We summarize 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

Constellation Energy issued the following fixed rate notes during 2002:

	Principal	Date Issued	Maturity and Repayment Date	Net Proceeds
		(In millions)		
6.35% Notes (interest payable semi-annually)	$ 600.0	3/02	4/07	$ 595.4

	Principal	Date Issued	Maturity and Repayment Date	Net Proceeds
7.00% Notes (interest payable semi-annually)	600.0	3/02	4/12	592.9
7.60% Notes (interest payable semi-annually)	600.0	3/02	4/32	592.8
6.125% Notes (interest payable semi-annually)	500.0	8/02	9/09	496.1
7.00% Notes (interest payable semi-annually)	100.0	12/02	4/12	102.1
7.60% Notes (interest payable semi-annually)	100.0	12/02	4/32	99.6
Total	$ 2,500.0			$ 2,478.9

We used a portion of the net proceeds to repay short-term borrowings, to prepay the sellers' note of $388.1 million originally issued for the acquisition of Nine Mile Point Nuclear Station (Nine Mile Point), and to fund other acquisitions.

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:

$6^{1}/_{2}$% Series, due 2003	$7^{1}/_{2}$% Series, due 2007
$6^{1}/_{8}$% Series, due 2003	$6^{5}/_{8}$% Series, due 2008
$5^{1}/_{2}$% Series, due 2004	

Holders of the Remarketed Floating Rate Series due September 1, 2006 have the option to require BGE to repurchase their bonds at face value on September 1 of each year. BGE is required to repurchase and retire at par any bonds that are not remarketed or purchased by the remarketing agent. BGE also has the option to redeem all or some of these bonds at face value each September 1.

On August 28, 2002, BGE called $11.8 million principal amount of its $7^{1}/_{2}$% Series, due April 15, 2023 First Refunding Mortgage Bonds in connection with its annual sinking fund. Bonds called were redeemed at the price of 100% of principal, plus accrued interest from April 15, 2002 to August 28, 2002.

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, 2002, BGE remains contingently liable for the $269.8 million outstanding balance of this debt.

On December 20, 2000, BGE issued $173.0 million of 6.75% Remarketable and Redeemable Securities (ROARS) due December 15, 2012. On December 15, 2002, BGE redeemed all the outstanding ROARS at 100% of the principal amount.

We show the weighted-average interest rates and maturity dates for BGE's fixed-rate medium-term notes outstanding at December 31, 2002 in the following table.

Series	Weighted-Average Interest Rate	Maturity Dates
B	8.62%	2006
C	7.97	2003
D	6.67	2004-2006
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	$	60.0	June 2007
6.75%, due 2012	$	25.0	June 2004 and 2007
6.73%, due 2012	$	25.0	June 2004 and 2007

BGE Obligated Mandatorily Redeemable Trust Preferred Securities

On June 15, 1998, BGE Capital Trust I (Trust), a Delaware business trust established by BGE, issued 10,000,000 Trust Originated Preferred Securities (TOPrS) for $250 million ($25 liquidation amount per preferred security) with a distribution rate of 7.16%.

The Trust used the net proceeds from the issuance of the common securities and the preferred securities to purchase a series of 7.16% Deferrable Interest Subordinated Debentures due June 30, 2038 (debentures) from BGE in the aggregate principal amount of $257.7 million with the same terms as the TOPrS. The Trust must redeem the TOPrS at $25 per preferred security plus accrued but unpaid distributions when the debentures are paid at maturity or upon any earlier redemption. BGE has the option to redeem the debentures at any time on or after June 15, 2003 or at any time when certain tax or other events occur.

The interest paid on the debentures, which the Trust will use to make distributions on the TOPrS, is included in "Interest expense" in our Consolidated Statements of Income and is deductible for income tax purposes.

BGE fully and unconditionally guarantees the TOPrS based on its various obligations relating to the trust agreement, indentures, debentures, and the preferred security guarantee agreement.

The debentures are the only assets of the Trust. The Trust is wholly owned by BGE because it owns all the common securities of the Trust that have general voting power.

For the payment of dividends and in the event of liquidation of BGE, the debentures are ranked prior to preference stock and common stock.

Other Nonregulated Businesses

In November 2002, our other nonregulated businesses entered into a long-term bank facility of $51.7 million in principal with an interest rate of 3.25% fixed rate plus 3 months Eurodollar rate (interest payable quarterly), due December 2008 for net proceeds of $50.4 million.

Revolving Credit Agreement

ComfortLink had a $50 million unsecured revolving credit agreement that matured September 26, 2002. Under this agreement, ComfortLink had no amount outstanding at December 31, 2002 and $46.0 million outstanding at December 31, 2001.

On December 18, 2001, 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 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 violated, the lending institutions can decline making new advances or issuing 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, 2002, the debt to capitalization ratios as defined in the credit agreements were no greater than 57%.

A BGE credit facility of $50.0 million that expires in August 2003 requires BGE to maintain a ratio of debt to capitalization equal to or less than 70%. At December 31, 2002, the debt to capitalization ratio for BGE as defined in the credit agreement was 54%. At December 31, 2002, no amounts were outstanding under the BGE facility.

Failure by Constellation Energy, or BGE, to comply with these covenants could result in the maturity of the debt outstanding under these facilities being accelerated. 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 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

All of our long-term borrowings mature on the following schedule (includes sinking fund requirements):

Year	Constellation Energy	Nonregulated Business	BGE
		(In millions)	
2003	$	$ 5.5	$ 284.2
2004		7.5	151.5
2005	300.0	8.1	43.2
2006		9.6	463.8
2007	600.0	10.5	127.6
Thereafter	1,900.0	308.6	829.7
Total long-term debt at December 31, 2002	$ 2,800.0	$ 349.8	$ 1,900.0

At December 31, 2002, we had long-term loans totaling $394.3 million that mature after 2002 which contain certain put options under which lenders could potentially require us to repay the debt prior to maturity. At December 31, 2002, $136.5 million is classified as current portion of long-term debt as a result of these provisions.

Weighted-Average Interest Rates for Variable Rate Debt

Our weighted-average interest rates for variable rate debt were:

At December 31,	**2002**	**2001**
Nonregulated Businesses (including Constellation Energy)		
Floating rate notes	%	4.95%
Loans under credit agreements	**4.42**	4.60
Mortgage and construction loans		4.39
Tax-exempt debt transferred from BGE	**1.97**	3.12
Other tax-exempt debt	**1.49**	1.75
BGE		
Remarketed floating rate series mortgage bonds	**1.91%**	4.49%
Floating rate reset notes		4.14

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.

9 Taxes

The components of income tax expense are as follows:

Year Ended December 31,	**2002**	**2001**	**2000**
	(Dollar amounts in millions)		
Income Taxes			
Current			
Federal	**$ 145.0**	$ 45.5	$ 148.2
State	**24.2**	27.0	48.2
Current taxes charged to expense	**169.2**	72.5	196.4
Deferred			

Year Ended December 31,	2002	2001	2000
Federal	**131.2**	(22.4)	53.9
State	**17.1**	(4.1)	(11.8)
Deferred taxes charged to expense	**148.3**	(26.5)	42.1
Investment tax credit adjustments	**(7.9)**	(8.1)	(8.4)
Income taxes per Consolidated Statements of Income	**$ 309.6**	$ 37.9	$ 230.1

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			
Income before income taxes (excluding BGE preference stock dividends)	**$ 848.4**	$ 133.5	$ 588.6
Statutory federal income tax rate	**35%**	35%	35%
Income taxes computed at statutory federal rate	**296.9**	46.7	206.0
Increases (decreases) in income taxes due to			
Depreciation differences not normalized on regulated activities	**4.8**	5.6	12.6
Amortization of deferred investment tax credits	**(7.9)**	(8.1)	(8.4)
Synthetic fuel tax credits flowed through to income	**(20.7)**	(13.4)	(6.5)
State income taxes, net of federal income tax benefit	**31.4**	13.5	31.7
Other	**5.1**	(6.4)	(5.3)
Total income taxes	**$ 309.6**	$ 37.9	$ 230.1
Effective income tax rate	**36.5%**	28.4%	39.1%

The major components of our net deferred income tax liability are as follows:

At December 31,	2002	2001
	(Dollar amounts in millions)	
Deferred Income Taxes		

At December 31,		**2002**		**2001**
Deferred tax liabilities				
Net property, plant and equipment	**$**	**1,242.4**	$	1,156.0
Regulatory assets, net		**110.7**		130.2
Power marketing and risk management activities, net		**285.5**		227.3
Financial investments and hedging instruments		**3.2**		153.9
Other		**130.3**		147.9
Total deferred tax liabilities		**1,772.1**		1,815.3
Deferred tax assets				
Accrued pension and postemployment benefit costs		**211.8**		132.7
Deferred investment tax credits		**30.0**		35.1
Nuclear decommissioning liability		**34.4**		32.1
Reduction of investments		**53.8**		82.3
Other		**111.4**		102.1
Total deferred tax assets		**441.4**		384.3
Deferred tax liability, net	**$**	**1,330.7**	$	1,431.0

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

10 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. 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 utility operations. 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.

Lease expense was:

- $19.4 million in 2002,
- $11.7 million in 2001, and
- $11.3 million in 2000

At December 31, 2002, we owed future minimum payments for long-term, noncancelable, operating leases as follows:

Year		*(In millions)*
2003	$	34.6
2004		50.8
2005		52.9
2006		21.7
2007		16.3
Thereafter		151.6
Total future minimum lease payments	$	327.9

The above table includes the operating lease payments for the High Desert project in California through 2006. The project is scheduled for completion in mid-2003.

The High Desert project uses an off-balance sheet financing structure through a special-purpose entity (SPE) that qualifies as an operating lease. Our wholly owned subsidiary, High Desert Power Project LLC, is supervising the construction of, and leasing, the High Desert project from High Desert Power Trust, an independent SPE created to own and lease the project to our subsidiary. Neither Constellation Energy nor any affiliate owns any equity or other interest in High Desert Power Trust, which is owned by a consortium of banks and other financial institutions. We provide a guaranty of High Desert Power Project LLC's obligations to the Trust.

Accounting rules presently in effect for SPEs formed prior to February 2003, require that an SPE lessor must have sufficient independent equity at risk in order for us not to consolidate it. High Desert Power Trust maintains such a level of equity at risk, since the owners of the Trust maintain a minimum of 3% real equity at risk. In January 2003, the FASB issued Interpretation No. 46, *Consolidation of Variable Interest Entities,* which will require us to consolidate the Trust based on the current lease structure beginning July 1, 2003. We discuss this further in *Note 1*.

Under the terms of the lease, we are required to make payments that represent all or a portion of the lease balance if construction is terminated prior to completion or we default under the lease.

In addition, we may be required to either post cash collateral equal to the outstanding lease balance or we may elect to purchase the property for the outstanding lease balance. At any time during the term of the lease we have the right to pay off the lease and acquire the asset from the lessor. At December 31, 2002, the outstanding lease balance plus other committed expenses was approximately $585 million.

The lease with the Trust contains several events of default that are commonly found in financings of this type, including failure to make all payments when due, failure to comply with all covenants, violation of material representations and warranties and change of control. In addition, several events of default are applicable to us as guarantor, including defaults in other material financing agreements and failure to own 100% of BGE's common stock.

At the conclusion of the lease term in 2006, we have the following options:

- renew the lease upon approval of the lessors,
- elect to purchase the property for a price equal to the lease balance at the end of the term, or
- request the lessor to sell the property.

If the lessor sells the property, we guarantee the payment of any difference between the sale proceeds and the lease balance at the time of sale up to a maximum amount of approximately 83% of such lease balance. The lease balance at the end of the term is currently estimated to be $600 million, which represents the estimated cost of the project; however, this may vary based on the ultimate cost of construction and interest incurred during the construction period.

11 Commitments, Guarantees, and Contingencies

Commitments

We have made substantial commitments in connection with our merchant energy, regulated gas, and other nonregulated businesses. These commitments relate to:

- purchase of electric generating capacity and energy,
- procurement and delivery of fuels, and
- capital for construction programs and loans.

Our merchant energy business has a long-term contract for the purchase of electric generating capacity and energy that expires in 2013. Portions of this contract became uneconomical upon the deregulation of electric generation. Therefore, we recorded a charge and accrued a corresponding liability based on the net present value of the excess of estimated contract costs over the market-based revenues to recover these costs over the remaining term of the contract. At December 31, 2002, the accrued portion of this contract was $9.2 million.

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 2003 and 2013. 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 2003 and 2013.

Our merchant energy business also has committed to contribute additional capital for our construction program and to make additional loans to some affiliates, joint ventures, and partnerships in which they have an interest.

At December 31, 2002, we estimate the future obligations of our merchant energy business in the following table:

	2003	2004	2005	2006	2007	Thereafter	Total
				(In millions)			
Purchased capacity and energy	$ 182.8	$ 106.5	$ 54.2	$ 33.6	$ 12.9	$ 73.1	$ 463.1
Fuel and transportation	618.5	243.8	70.4	117.6	27.6	94.2	1,172.1
Capital and loans	32.7	0.5					33.2
Total future obligations	$ 834.0	$ 350.8	$ 124.6	$ 151.2	$ 40.5	$ 167.3	$ 1,668.4

Our regulated gas business entered into various long-term contracts that expire from 2004 to 2012 for the procurement, transportation, and storage of gas. These contracts are recoverable under BGE's gas cost adjustment clause discussed in *Note 1*.

BGE Home Products & Services has gas purchase commitments of $8.4 million in 2003 and $2.7 million in 2004 related to its gas program.

Long-Term Power Sales Contracts

We entered into long-term power sales contracts in connection with our load-serving activities. We also entered into long-term power sales contracts associated with certain of our power plants. Our load-serving power sales contracts extend for terms through 2009 and provide for the sale of full requirements energy to electricity distribution utilities and certain retail customers. Our power sales contracts associated with our power plants extend for terms into 2011 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.

Sale of Receivables

BGE Home Products & Services has an agreement to sell on an ongoing basis an undivided interest in a designated pool of customer receivables. Under the agreement, BGE Home Products & Services can sell up to a total of $50 million. Under the terms of the agreement, the buyer of the receivables has limited recourse against BGE Home Products & Services. BGE Home Products & Services recorded reserves for credit losses. At December 31, 2002, BGE Home Products & Services sold $47.7 million of receivables under the agreement.

Guarantees

The terms of our guarantees are as follows:

	Payments/Expiration				
	2003	2004-2005	2006-2007	Thereafter	Total
Competitive Supply	$ 1,758.8	$ 167.0	$ 35.8	$ 189.4	$ 2,151.0
Other	16.5	2.8	602.1	415.9	1,037.3
Total Guarantees	$ 1,775.3	$ 169.8	$ 637.9	$ 605.3	$ 3,188.3

At December 31, 2002, Constellation Energy had a total of $3,188.3 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 $2,151.0 million on behalf of its subsidiaries for competitive supply activities. These guarantees are put into place in order to allow the subsidiaries flexibility needed to conduct business with counterparties without having to post substantial cash collateral. While the face amount of these guarantees is $2,151.0 million, we do not expect to fund the full amount as our calculated fair value of obligations covered by these guarantees was $519.8 million at December 31, 2002. The recorded fair value of obligations in our Consolidated Balance Sheets for these guarantees was $489.6 million at December 31, 2002.

Constellation Energy guaranteed $104.5 million primarily on behalf of Nine Mile Point in connection with our acquisition in 2001.

Constellation Energy guaranteed $56.6 million on behalf of our other nonregulated businesses primarily for loans and performance bonds of which $25.7 million was recorded in our Consolidated Balance Sheets at December 31, 2002.

Constellation Energy guaranteed $600.0 million relating to the High Desert project as discussed in more detail in *Note 10*. This amount is included in the "Other" guarantees for 2006 in the table on the previous page.

Our merchant energy business guaranteed $12.9 million for loans related to certain power projects in which we have an investment.

BGE guaranteed two-thirds of certain debt of Safe Harbor Water Power Corporation, an unconsolidated investment. At December 31, 2002, Safe Harbor Water Power Corporation had outstanding debt of $20.0 million. The maximum amount of BGE's guarantee is $13.3 million. Additionally, BGE guaranteed the TOPrS of $250.0 million as discussed in *Note 8*.

The total fair value of the obligations for our guarantees recorded in our Consolidated Balance Sheets was $765.3 million and not the $3.2 billion of total guarantees. We assess the risk of loss from these guarantees to be minimal.

Environmental Matters

We are subject to regulation by various federal, state and local authorities with regard to:

- air quality,
- water quality, and
- disposal of hazardous substances.

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 siting and developing, 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, special, protected and cultural resources (such as wetlands, endangered species, and archeological/historical resources), chemical, and waste handling and noise impacts. Our activities require complex and often lengthy processes to obtain approvals, permits, or licenses for new, existing, or modified facilities. Additionally, the use and handling of various chemicals or hazardous materials (including wastes) requires preparation of release prevention plans and emergency response procedures. As new laws or regulations are promulgated, we assess their applicability and implement the necessary modifications to our facilities or their operation, as required.

We discuss the significant matters below.

Clean Air Act

The Clean Air Act affects both existing generating facilities and new projects. The Clean Air Act and many state laws require significant reductions in SO_2 (sulfur dioxide) and NO_x (nitrogen oxide) emissions that result from burning fossil fuels. The Clean Air Act also contains other provisions that could materially affect some of our projects. Various provisions may require permits, inspections, or installation of additional pollution control technology or may require the purchase of emission allowances.

Certain of these provisions are described in more detail below.

On October 27, 1998, the Environmental Protection Agency (EPA) issued a rule requiring 22 Eastern states and the District of Columbia to reduce emissions of NO_X. Among other things, the EPA's rule establishes an ozone season, which runs from May through September, and a NO_X emission budget for each state, including Maryland and Pennsylvania. The EPA rule requires states to implement controls sufficient to meet their NO_X budget by May 30, 2004. Coal-fired power plants are a principal target of NO_X reductions under this initiative.

Many of our generation facilities are subject to NO_X reduction requirements under the EPA rule, including those located in Maryland and Pennsylvania. At the Brandon Shores and Wagner facilities, we installed emission reduction equipment to meet Maryland regulations issued pursuant to EPA's rule. The owners of the Keystone plant in Pennsylvania are installing emissions reduction equipment by July 2003 to meet Pennsylvania regulations issued pursuant to EPA's rule. We estimate our costs for the equipment needed at this plant will be approximately $35 million. Through December 31, 2002, we have spent approximately $26 million.

The EPA established new National Ambient Air Quality Standards for very fine particulates and revised standards for ozone attainment that were upheld after various court appeals. While these standards may require increased controls at some of our fossil generating plants in the future, implementation could be delayed for several years. We cannot estimate the cost of these increased controls at this time because the states, including Maryland, Pennsylvania, and California, still need to determine what reductions in pollutants will be necessary to meet the EPA standards.

The EPA and several states have filed suits against a number of coal-fired power plants in Mid-Western and Southern states alleging violations of the deterioration prevention and non-attainment provisions of the Clean Air Act's new source review requirements. In 2000, and again in 2002, using its broad investigatory powers, the EPA requested information relating to modifications made to our Brandon Shores, Crane, and Wagner plants in Baltimore, Maryland. The EPA also sent similar, but narrower, information requests to two of our newer Pennsylvania waste-coal burning plants. This information is to determine compliance with the Clean Air Act and state implementation plan requirements, including potential application of federal New Source Performance Standards. We have responded to the EPA and as of the date of this report the EPA has taken no further action.

In general, such standards can require the installation of additional air pollution control equipment upon the major modification of an existing plant. Although there have not been any new source review-related suits filed against our facilities, there can be no assurance that any of them will not be the target of an action in the future. Based on the levels 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.

The Clean Air Act requires the EPA to evaluate the public health impacts of emissions of mercury, a hazardous air pollutant, from coal-fired plants. The EPA decided to control mercury emissions from coal-fired plants. Compliance could be required by approximately 2007. We believe final regulations could be issued in 2004 and would affect all coal-fired boilers. The cost of compliance with the final regulations could be material.

Future initiatives regarding greenhouse gas emissions and global warming continue to be the subject of much debate. The related Kyoto Protocol was signed by the United States but has since been rejected by the President, who instead has asked for an 18% decrease in carbon intensity on a voluntary basis. Future initiatives on this issue and the ultimate effects of the Kyoto Protocol and the President's initiatives on us are unknown at the date of this report. 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 carbon dioxide emissions, a principal greenhouse gas. Our compliance costs with any mandated federal greenhouse gas reductions in the future could be material.

Clean Water Act

Our facilities are subject to a variety of federal and state regulations governing existing and potential water/wastewater and stormwater discharges.

In April 2002, the EPA proposed rules under the Clean Water Act that require that cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts. These rules pertain to existing utilities and non-utility power producers that currently employ a cooling water intake structure and whose flow exceeds 50 million gallons per day. A final action on the proposed rules is expected by February 2004. The proposed rule may require the installation of additional intake screens or other protective measures, as well as extensive site specific study and monitoring requirements. There is also the possibility that the proposed rules may lead to the installation of cooling towers on four of our fossil and both of our nuclear facilities. Our compliance costs associated with the final rules could be material.

Waste Disposal

The EPA and several state agencies have notified us that we are considered a potentially responsible party with respect to the cleanup of certain environmentally contaminated sites owned and operated by others. We cannot estimate the cleanup costs for all of these sites.

However, based on a Record of Decision issued by the EPA in 1997, we can estimate that BGE's current 15.47% share of the reasonably possible cleanup costs at one of these sites, Metal Bank of America, a metal reclaimer in Philadelphia, could be as much as $1.3 million higher than amounts we believe are probable and have recorded as a liability in our Consolidated Balance Sheets. There has been no significant activity with respect to this site since the EPA's Record of Decision in 1997.

In late December 1996, BGE signed a consent order with the Maryland Department of the Environment that required 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. BGE submitted the required remedial action plans and they were approved by the Maryland Department of the Environment. Based on these plans, the costs BGE considers to be probable to remedy the contamination are estimated to total $47 million. BGE recorded these costs as a liability on its Consolidated Balance Sheets and deferred these costs, net of accumulated amortization and amounts it recovered from insurance companies, as a regulatory asset. Because of the results of studies at this site, it is reasonably possible that additional costs could exceed the amount BGE recognized by approximately $14 million. Through December 31, 2002, BGE spent approximately $39 million for remediation at this site. BGE also investigated other small sites where gas was manufactured in the past. We do not expect the cleanup costs of the remaining smaller sites to have a material effect on our financial results.

Litigation

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

California

Baldwin Associates, Inc. v. Gray Davis, Governor of California and 22 other defendants (including Constellation Power Development, Inc., a subsidiary of Constellation Power, Inc.) This class action lawsuit was filed on October 5, 2001 in the Superior Court, County of San Francisco. The action seeks damages of $43 billion, recession and reformation of approximately 38 long-term power purchase contracts, and an injunction against improper spending by the state of California.

Constellation Power Development, Inc. is named as a defendant but does not have a power purchase agreement with the State of California. However, our High Desert Power Project does have a power purchase agreement with the California Department of Water Resources. In 2002, the court issued an order to the plaintiff asking that he show cause why he had not yet served the defendants. In April 2002, a second show cause order was issued. After several postponements, a hearing is now scheduled in March 2003 on that order.

NewEnergy

Constellation NewEnergy, Inc. v. PowerWeb Technology, Inc. Prior to our acquisition, NewEnergy filed a complaint on May 9, 2002 in the U.S. District Court of Eastern Pennsylvania seeking approximately $100,000 in direct damages relating to a contract previously entered into with PowerWeb. PowerWeb Technology has counter-claimed seeking $100 million in damages against NewEnergy alleging a breach of a non-disclosure agreement by misappropriation of trade secrets. To date, discovery has just begun. We cannot predict the timing, or outcome, of the action or its possible effect on our financial results. However, based on the information available to Constellation Energy at this time, we believe NewEnergy has meritorious defenses to the PowerWeb Technology counterclaim.

Mercury Poisoning

Beginning in September 2002, BGE, Constellation Energy, and several other defendants have been involved in numerous actions 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 50 cases have been filed to date, with each case seeking $90 million in damages from the group of defendants. The claims were filed in the Circuit Court for Baltimore City, Maryland beginning in September 2002. The plaintiffs have filed motions to remand the cases back to the Baltimore City Circuit Court. At this time no discovery has occurred. We believe that we have meritorious defenses and intend to defend the action vigorously. However, we cannot predict the timing, or outcome, of these cases, or their possible effect on our, or BGE's, financial results.

Employment Discrimination

Miller, et. al v. Baltimore Gas and Electric Company, et al. This action was filed on September 20, 2000 in the U.S. District Court for the District of Maryland. Besides BGE, Constellation Energy Group, Constellation Nuclear, and Calvert Cliffs Nuclear Power Plant are also named defendants. The action seeks class certification for approximately 150 past and present employees and alleges racial discrimination at Calvert Cliffs Nuclear Power Plant. The amount of damages is unspecified, however the plaintiffs seek back and front pay, along with compensatory and punitive damages. The Court scheduled a briefing process for the motion to certify the case as a class action suit. The briefing process is scheduled to end in July 2003. We do not believe class certification is appropriate and we further believe that we have meritorious defenses to the underlying claims and intend to defend the action vigorously. However, we cannot predict the timing, or outcome, of the action or its 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. The actions relate to two types of claims.

The first type is direct claims by individuals exposed to asbestos. BGE is involved in these claims with approximately 70 other defendants. Approximately 600 individuals that were never employees of BGE each claim $6 million in damages ($2 million compensatory and $4 million punitive). These claims were filed in the Circuit Court for Baltimore City, Maryland in the summer of 1993. 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 plaintiff's employers, and
- the date on which the exposure allegedly occurred.

To date, 67 of these cases were settled for amounts that were not significant. Approximately 300 cases are scheduled for trial in 2003.

The second type is claims by one manufacturer Pittsburgh Corning Corp. (PCC) against BGE and approximately eight others, as third-party defendants. On April 17, 2000, PCC declared bankruptcy.

These claims relate to approximately 1,500 individual plaintiffs and were filed in the Circuit Court for Baltimore City, Maryland in the fall of 1993. To date, about 375 cases have been resolved, all without any payment by BGE. BGE does not know the specific facts necessary to estimate its potential liability for these claims. The specific facts we do not know include:

- the identity of BGE facilities containing asbestos manufactured by the manufacturer,
- the relationship (if any) of each of the individual plaintiffs to BGE,
- the settlement amounts for any individual plaintiffs who are shown to have had a relationship to BGE, and
- the dates on which/places at which the exposure allegedly occurred.

Until the relevant facts for both types of claims 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.

Other

McCray, et. al.v. Baltimore Gas and Electric Company On June 10, 2002, a suit was filed in the Circuit Court of Baltimore City, Maryland seeking a total of $585 million in compensatory and punitive damages from BGE as a result of a fire in a home that caused five fatalities. Electricity to the home was shut off. BGE believes it has meritorious defenses and intends to defend the action vigorously. However, we cannot predict the timing, or outcome, of the action or its possible effect on our, or BGE's, financial results.

Storage of Spent Nuclear Fuel

On February 14, 2002, the Secretary of Energy submitted to the President a recommendation for approval of the Yucca Mountain site for the development of a nuclear waste repository for the disposal of spent nuclear fuel and high level nuclear waste from the nation's defense activities. In July 2002, the President signed a resolution approving the Yucca Mountain site after receiving the approval of this site from the U.S. Senate and House of Representatives. This action allows the Department of Energy to apply to the NRC to license the project. The Department of Energy expects that this facility will open in 2010. However, the opening of Yucca Mountain could be delayed due to multiple lawsuits initiated by the State of Nevada and other interested parties, the NRC licensing hearings, and other issues related to the site.

Nuclear Insurance

We maintain nuclear insurance coverage for Calvert Cliffs and Nine Mile Point 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.

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 insurance company within a 12-month period, they would be treated as one event and the owners of the plants would share one full limit of liability (currently $3.24 billion).

If there were an accident or an extended outage at any unit of Calvert Cliffs or Nine Mile Point, it could have a substantial adverse financial effect on us.

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, approximately $9.6 billion. This limit of liability consists of the maximum available commercial insurance of $300 million and the remaining $9.3 billion is provided through mandatory participation in an industry-wide retrospective assessment program. Under this retrospective assessment program, we can be assessed up to $352.4 million per incident at any commercial reactor in the country, payable at no more than $40 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. In addition, the U.S. Congress could impose additional revenue-raising measures to pay claims.

The Price-Anderson Act expired in August 2002. However, the Price-Anderson Act will remain in effect in its current form for existing reactors until it is renewed. A renewal bill was introduced in Congress in January 2003 to extend the Act for 15 years from August 1, 2002. The bill proposes a change in the annual retrospective premium limit from $10 million to $15 million per reactor per incident and a change in the maximum potential assessment from $88.1 million to $98.7 million per reactor per incident. If approved, these changes would increase the amount we could be assessed to $394.8 million per incident, payable at no more than $60 million per incident per year. We do not know what impact any other changes to the Act may have on us until a final resolution is reached.

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 an annual industry aggregate limit of $200 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 above, 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 premiums assessments. 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 and an additional $2.25 billion in excess coverage for property damage, decontamination, and premature decommissioning liability for Calvert Cliffs or Nine Mile Point. This coverage currently is purchased through an 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 $56.2 million.

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, $335.4 million for Unit 1 of Nine Mile Point, and $412.6 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 $82.5 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 TRIA.

Losses resulting from non-certified acts of terrorism are covered by an industry mutual insurance program. This program, which expires May 1, 2003, provides limits of $50 million per occurrence and is subject to a term aggregate limit of $100 million. These limits are shared among all companies participating in the program. The mutual insurer may renew this program depending upon the availability of reinsurance at the program's expiration. If terrorist acts at any of our facilities result in a loss exceeding this coverage, it could have a significant adverse impact on our financial results.

California Power Purchase Agreements

Our merchant energy business has $260.6 million invested in operating power projects of which our ownership percentage represents 137 megawatts of electricity that are sold to Pacific Gas & Electric (PGE) and to Southern California Edison (SCE) in California under power purchase agreements.

As a result of ongoing litigation before the FERC regarding sales into the spot markets of the California Independent System Operator and Power Exchange, we estimate that we may be required to pay refunds of between $3 and $4 million for transactions that we entered into with these entities for the period between October 2000 and June 2001. However, our estimate is based on current information, and because litigation is ongoing, new events could occur that could cause the actual amount, if any, to be materially different from our estimate.

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12 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. These swaps are designated as cash-flow hedges under SFAS No. 133 in anticipation of planned financing transactions as discussed in *Note 1*. The notional amounts of the contracts do not represent amounts that are exchanged by the parties and are not a measure of our exposure to market or credit risks. The notional amounts are used in the determination of the cash settlements under the contracts.

Prior to the March 2002 issuance of $1.8 billion of debt as discussed in *Note 8*, we entered into various forward starting interest rate swap contracts to manage our interest rate exposure related to this debt issuance. In 2001, we entered into swaps that had notional or contract amounts that totaled $800 million with an average rate of 4.9%. At December 31, 2001, the fair value of these swaps was an unrealized pre-tax gain of $36.3 million. In the first quarter of 2002, we entered into additional forward starting interest rate swaps with notional amounts that totaled $700 million with an average rate of 5.9%. All of these swap contracts expired at the end of March 2002 with a gain of $53.7 million.

In addition, we entered into forward starting interest rate swap contracts with notional amounts that totaled $400 million with an average rate of 5.1% to manage our interest rate exposure related to the issuance of $500 million of debt in 2002 as discussed in *Note 8*. These swap contracts expired in 2002 with a loss of $16.7 million.

We will reclassify the $37.0 million net gain from these swaps from "Accumulated other comprehensive income" into "Interest expense" and include them in earnings during the periods in which the hedged interest payments occur. We expect to reclassify $3.7 million of pre-tax net gains related to our expired swap contracts from "Accumulated other comprehensive income" into "Interest expense" in 2003.

Commodity Prices

Our origination and risk management operation 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, 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, 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, and
- fixing the price for a portion of anticipated energy purchases to supply our load-serving customers.

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

At December 31, 2002, 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 2003 through 2010 under SFAS No. 133.

At December 31, 2002, our merchant energy business recorded net unrealized pre-tax losses of $45.3 million on these hedges, net of associated deferred income tax effects, in "Accumulated other comprehensive income." We expect to reclassify $24.7 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, 2002. However, the actual amount reclassified into earnings could vary from the amounts recorded at December 31, 2002 due to future changes in market prices. In 2002, we recognized $1.4 million of losses in earnings related to hedge ineffectiveness.

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 where it was practicable to estimate fair value: the fair value is based on quoted market prices where available, and
- for 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, and we describe some of the items separately later in this Note.

At December 31,	2002		2001	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In millions)			
Investments and other assets for which it is:				
Practicable to estimate fair value	**$ 755.1**	**$ 755.1**	$ 1,183.6	$ 1,183.6
Not practicable to estimate fair value	**24.2**	**N/A**	25.8	N/A
Fixed-rate long-term debt	**4,713.9**	**5,018.8**	2,945.3	3,069.6
Variable-rate long-term debt	**335.9**	**335.9**	1,179.1	1,179.1

It was not practicable to estimate the fair value of investments held by our nonregulated businesses in several financial partnerships that invest in nonpublic debt and equity securities. This is because the timing and amount of cash flows from these investments are difficult to predict. We report these investments at their original cost in our Consolidated Balance Sheets.

The investments in financial partnerships totaled $24.2 million at December 31, 2002, representing ownership interests up to 10% and $25.8 million at December 31, 2001, representing ownership interests up to 11%. The total assets of all of these partnerships totaled $5.8 billion at December 31, 2001 (which is the latest information available).

13 Stock-Based Compensation

Under our long-term incentive plans, we granted stock options, performance and service-based restricted stock, 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, 2002, we had stock options and restricted stock grants outstanding as discussed below.

Non-Qualified Stock Options

Options are granted at prices not less than the market value of the common stock at the date of grant, become vested over a period up to five years, and expire ten years from the date of grant. In accordance with APB No. 25, no compensation expense is recognized for these stock option awards.

In February 2002, our Committee on Management of the Board of Directors granted options, contingent on shareholder approval of our long-term incentive plan, with an exercise price equal to fair market value of our stock on the date of grant of $27.93. Our shareholders approved the plan at the annual meeting in May 2002 when then stock price had increased to $31.21. The difference between the exercise price and the fair market value in May when the shareholder approval contingency was satisfied was $6.3 million and is being amortized to compensation expense over a period up to five years. In 2002, we recorded compensation expense of $3.0 million related to this grant.

All other stock options grants have an exercise price equal to or greater than market value on the date of grant and were not subject to any future contingencies, therefore no compensation expense has been recognized. We reverse any expense associated with stock options that are canceled or forfeited prior to the vesting of the grants. Summarized information for our stock option grants is as follows:

	2002		2001		2000	
	Shares	Weighted-Average	Shares	Weighted-Average	Shares	Weighted-Average

	2002		2002	2001		2001	2000		2000
			Exercise Price			**Exercise Price**			**Exercise Price**
				(In thousands, except per share amounts)					
Outstanding, beginning of year	**2,646**	**$**	**30.73**	2,420	$	34.65		$	
Granted with Exercise Prices:									
At fair market value	**1,708**		**30.62**	1,015		25.08	2,462		34.64
Less than fair market value on the date contingency was satisfied (1)	**1,935**		**27.93**						
Greater than fair market value	**103**		**31.21**						
Total granted	**3,746**		**29.25**	1,015		25.08	2,462		34.64
Exercised				(512)		(34.25)			
Canceled/Expired	**(311)**		**34.01**	(277)		(37.74)	(42)		(34.25)
Outstanding, end of year	**6,081**	**$**	**29.65**	2,646	$	30.73	2,420	$	34.65
Exercisable, end of year	**1,413**	**$**	**30.78**	235	$	34.25			

Weighted-average fair value per share of options granted with Exercise Prices:		**2002**		2001		2000
At fair market value	**$**	**7.79**	$	9.27	$	5.60
Less than fair market value on the date contingency was satisfied (1)	**$**	**9.15**				
Greater than fair market value	**$**	**5.89**				

(1) Shares were granted in February 2002 with an exercise price equal to fair market value of the stock on the grant date, and the grant was subject to shareholder approval of our long-term incentive plan. At the date of shareholder approval, the fair market value of the stock was higher than the grant date fair market value. Therefore, the difference is being amortized to compensation expense.

The following table summarizes information about stock options outstanding at December 31, 2002 (shares in thousands):

Range of Exercise Prices	Number Outstanding	Weighted-Average Remaining Contractual Life	Number Exercisable
$21.47 34.25	6,081	8.8 years	1,413

Restricted Stock Awards

In addition, we issue common stock based on meeting certain performance and/or service goals. This stock vests to participants at various times ranging from one to five years if the performance and/or service goals are met. In accordance with APB No. 25, we recognize compensation expense for our performance-based awards using the variable accounting method, whereby we amortize the value of the market price of the underlying stock on the date of grant adjusted for subsequent changes in fair market value through the lapse date to compensation expense over the performance period. We account for our service-based awards using the fixed accounting method, whereby we amortize the value of the market price of the underlying stock on the date of grant to compensation expense over the service period. We reverse any expense associated with restricted stock that is canceled or forfeited during the performance or service period.

We recorded compensation expense related to our restricted stock awards of $6.6 million in 2002 and $16.3 million in 2000. In 2001, due to non-attainment of performance criteria, we recorded a reduction to compensation expense of $10.1 million. Summarized share information for our restricted stock awards is as follows:

	2002	2001	2000
	(In thousands, except per share amounts)		
Outstanding, beginning of year	**435**	377	323
Granted	**344**	87	353
Released to participants	**(170)**		(277)
Canceled	**(295)**	(29)	(22)
Outstanding, end of year	**314**	435	377
Weighted-average fair value restricted stock granted	**$ 27.23**	$ 35.24	$ 32.89

Equity-Based Grants

In 2002, we recorded compensation expense of $0.5 million related to equity-based grants to members of the Board of Directors.

Pro-forma Information

Disclosure of pro-forma information regarding net income and earnings per share is required under SFAS No. 123, which uses the fair value method. The fair values 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:

	2002	2001	2000
Risk-free interest rate	**4.45%**	4.79%	6.73%
Expected life (in years)	**5.0**	5.0	10.0
Expected market price volatility factors	**31.9%**	41.3%	21.0%
Expected dividend yields	**3.3%**	1.8%	5.7%

We disclose the pro-forma effect on net income and earnings per share in accordance with SFAS No. 148, *Accounting for Stock-Based Compensation Transition and Disclosure*, in *Note 1*.

14 Acquisitions

Acquisition of Alliance

On December 31, 2002, we purchased Alliance Energy Services, LLC and Fellon-McCord Associates, Inc. (collectively, Alliance) from Allegheny Energy, Inc. These businesses provide gas supply and transportation services and energy consulting services to large commercial and industrial customers primarily in the Midwest region, but also in other competitive energy markets including the Northeast, Mid-Atlantic, Texas and California regions. We acquired 100% ownership of these companies for a note payable of $21.2 million that was settled in cash on January 2, 2003. We acquired cash of $4.6 million as part of the purchase. We include these companies in our merchant energy business segment.

Our preliminary purchase price allocation for the net assets acquired is as follows:

At December 31, 2002

	(In millions)	
Cash	$	4.6
Other Current Assets		89.1
Total Current Assets		93.7
Net Property, Plant and Equipment		0.6
Goodwill		10.0
Other Assets		3.7
Total Assets Acquired		108.0
Current Liabilities		84.5
Deferred Credits and Other Liabilities		2.3
Net Assets Acquired	$	21.2

We recorded the existing contracts at fair value as part of the purchase price allocation. The preliminary net fair value of the contracts was $4.0 million. We recorded the fair value of these contracts as follows:

Net fair value of acquired contracts

	(In millions)	
Current Assets	$	20.8
Noncurrent Assets		3.7
Total Assets		24.5
Current Liabilities		18.2
Noncurrent Liabilities		2.3
Total Liabilities		20.5
Net fair value of acquired contracts	$	4.0

We will amortize this value over a period extending through 2005. The weighted-average amortization period is approximately one year and represents the expected contract duration.

There are further refinements to the preliminary valuation of the existing contracts that have not been finalized that could impact our purchase price allocation.

On an unaudited pro-forma basis, had the acquisition of Alliance occurred on the first day of each of the years presented below, our nonregulated revenues and total revenues would have been as follows:

Year Ended December 31,	**2002**	**2001**	**2000**

Year Ended December 31,	2002	2001	2000
		(In millions)	
Nonregulated revenues			
As reported	**$ 2,166.9**	$ 1,164.9	$ 1,035.9
Pro-forma	**2,706.6**	1,659.5	1,381.0
Total revenues			
As reported	**$ 4,703.0**	$ 3,878.8	$ 3,774.4
Pro-forma	**5,242.7**	4,373.4	4,119.5

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 Alliance occurred on the first day of each of the years presented.

Acquisition of NewEnergy

On September 9, 2002, we purchased AES NewEnergy, Inc. from AES Corporation. Subsequent to the acquisition, we renamed AES NewEnergy, Inc. as Constellation NewEnergy, Inc. (NewEnergy). NewEnergy is a leading national provider of electricity, natural gas, and energy services, serving approximately 4,300 megawatts of load associated with large commercial and industrial customers in competitive energy markets including the Northeast, Mid-Atlantic, Midwest, Texas and California. We acquired 100% ownership of NewEnergy for cash of $250.3 million, including $1.4 million of direct costs associated with the acquisition. We acquired cash of $45.5 million as part of the purchase. We include NewEnergy in our merchant energy business segment.

Our preliminary purchase price allocation for the net assets acquired is as follows:

At September 9, 2002

	(In millions)
Cash	$ 45.5
Other Current Assets	376.5
Total Current Assets	422.0
Net Property, Plant and Equipment	7.0
Goodwill	105.0
Other Assets	46.9
Total Assets Acquired	580.9
Current Liabilities	276.3
Deferred Credits and Other Liabilities	54.3
Net Assets Acquired	$ 250.3

We recorded the existing contracts at fair value as part of the purchase price allocation. The preliminary net fair value of the contracts was $54.8 million. We recorded the fair value of these contracts as follows:

Net fair value of acquired contracts

	(In millions)
Current Assets	$ 78.6
Noncurrent Assets	45.0
Total Assets	123.6

Net fair value of acquired contracts

Current Liabilities		46.8
Noncurrent Liabilities		22.0
Total Liabilities		68.8
Net fair value of acquired contracts	$	54.8

We will amortize this value over a period extending through 2007. The weighted-average amortization period is approximately 2 years and represents the expected contract duration.

Currently, the following items have not been finalized that could impact our purchase price allocation:

- adjustments to the preliminary estimates of severance costs recorded as current liabilities associated with the integration of NewEnergy into our operations, and
- outcome of litigation matters.

On an unaudited pro-forma basis, had the acquisition of NewEnergy occurred on the first day of each of the years presented below, our nonregulated revenues and total revenues would have been as follows:

Year Ended December 31,	**2002**		2001		2000	
			(In millions)			
Nonregulated revenues						
As reported	**$**	**2,166.9**	$	1,164.9	$	1,035.9
Pro-forma		**3,307.7**		1,885.1		1,584.7
Total revenues						
As reported	**$**	**4,703.0**	$	3,878.8	$	3,774.4
Pro-forma		**5,843.8**		4,599.0		4,323.2

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 NewEnergy occurred on the first day of each of the years presented.

Acquisition of Nine Mile Point

On November 7, 2001, we completed our purchase of Nine Mile Point located in Scriba, New York. Nine Mile Point consists of two boiling-water reactors. Unit 1 is a 609-megawatt reactor that entered service in 1969. Unit 2 is a 1,148-megawatt reactor that began operation in 1988.

Nine Mile Point Nuclear Station, LLC, a subsidiary of Constellation Nuclear, purchased 100 percent of Nine Mile Point Unit 1 and 82 percent of Unit 2. Approximately one-half of the purchase price, or $380 million, in addition to settlement costs of $2.7 million, was paid at closing. The remainder was financed through the sellers in a note to be repaid over five years with an interest rate of 11.0%. This note was prepaid in April 2002. The sellers also transferred to us approximately $442 million in decommissioning funds. As a result of this purchase, we own 1,550 megawatts of Nine Mile Point's 1,757 megawatts of total generating capacity.

Niagara Mohawk Power Corporation was the sole owner of Nine Mile Point Unit 1. The co-owners of Unit 2 who sold their interests are: Niagara Mohawk (41 percent), New York State Electric and Gas (18 percent), Rochester Gas & Electric Corporation (14 percent), and Central Hudson Gas & Electric Corporation (9 percent). The Long Island Power Authority will continue to own 18 percent of Unit 2.

We will sell 90 percent of our share of Nine Mile Point's output back to the sellers at an average price of nearly $35 per megawatt-hour for approximately 10 years under power purchase agreements. The contracts for the output are on a unit contingent basis (if the output is not available because the plant is not operating, there is no requirement to provide output from other sources).

Nine Mile Point Net Assets Acquired

At November 7, 2001

	(In millions)
Current Assets	$ 138.4
Nuclear Decommissioning Trust Fund	441.7
Net Property, Plant and Equipment	280.3
Intangible Assets (details below)	37.6
Total Assets Acquired	898.0
Current Liabilities	18.5
Deferred Credits and Other Liabilities	108.7
Net Assets Acquired	770.8
Note to Sellers	388.1
Total Cash Paid	$ 382.7

The intangible assets acquired consist of the following:

Description	**Amount**	**Weighted-Average Useful Life**
	(In millions)	*(In years)*
Operating procedures and manuals	$ 22.3	10
Permits and licenses	13.0	27
Software	2.3	5
Total intangible assets	$ 37.6	

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15 Related Party Transactions BGE

Income Statement

BGE is providing standard offer service to customers at fixed rates over various time periods during the transition period, July 1, 2000 to June 30, 2006, for those customers that do not choose an alternate supplier. Our origination and risk management operation is under contract to provide BGE with the energy and capacity required to meet its standard offer service obligations for the first three years of the transition period, and 90% of the energy and capacity for the final three years (July 1, 2003 June 30, 2006) of the transition period. The cost of BGE's purchased energy from nonregulated affiliates of Constellation Energy to meet its standard offer service obligation was $1,080.5 million for the year ended

December 31, 2002, $1,150.1 million for the year ended December 31, 2001, and $581.0 million for the year ended December 31, 2000.

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. Management believes this method of allocation is reasonable and approximates the cost BGE would have incurred as an unaffiliated entity. These costs were $32.2 million for the year ended December 31, 2002, $27.1 million for the year ended December 31, 2001, and $21.6 million for the year ended December 31, 2000.

Balance Sheet

BGE participates in a cash pool under a Master Demand Note agreement with Constellation Energy. Under this arrangement, participating subsidiaries may invest in or borrow from the pool at market interest rates. Constellation Energy administers the pool and invests excess cash in short-term investments or issues commercial paper to manage consolidated cash requirements. Under this arrangement, BGE had invested $338.1 million at December 31, 2002 and $439.1 million at December 31, 2001.

Amounts related to corporate functions performed at the Constellation Energy holding company, BGE's purchases to meet its standard offer service obligation, and BGE's charges to Constellation Energy and its nonregulated affiliates for certain services it provides them result in intercompany balances on BGE's Consolidated Balance Sheets.

Management believes its allocation methods are reasonable and approximate the costs that would be charged to unaffiliated entities.

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16 Quarterly Financial Data (Unaudited)

Our quarterly financial information has not been audited but, in management's opinion, includes all adjustments necessary for a fair presentation. Our utility 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.

2002 Quarterly Data Constellation Energy

	Revenues	Income from Operations	Earnings Applicable to Common Stock	Earnings Per Share of Common Stock
	(In millions, except per-share amounts)			
Quarter Ended				
March 31	**$ 1,040.0**	**$ 418.6**	**$ 228.6**	**$ 1.40**
June 30	**1,020.8**	**184.9**	**81.3**	**0.50**
September 30	**1,270.3**	**308.0**	**150.7**	**0.92**
December 31	**1,371.9**	**174.7**	**65.0**	**0.39**
Year Ended				
December 31	**$ 4,703.0**	**$ 1,086.2**	**$ 525.6**	**$ 3.20**

2002 Quarterly Data BGE

	Revenues	Income from Operations	Earnings Applicable to Common Stock

	Revenues	Income from Operations	Earnings Applicable to Common Stock
		(In millions)	
Quarter Ended			
March 31	**$ 683.7**	**$ 113.0**	**$ 43.9**
June 30	**572.9**	**73.1**	**20.3**
September 30	**668.5**	**87.3**	**30.6**
December 31	**622.2**	**92.9**	**35.1**
Year Ended			
December 31	**$ 2,547.3**	**$ 366.3**	**$ 129.9**

First quarter results include:

Constellation Energy and BGE

workforce reduction costs totaling $15.6 million after-tax, of which BGE recorded $12.6 million.

Constellation Energy

gain on the sale of investments, including Orion, of $164.2 million after-tax.

Second quarter results include:

Constellation Energy and BGE

workforce reduction costs totaling $8.0 million after-tax, of which BGE recorded $4.8 million.

Constellation Energy

gain on the sale of investments of $1.9 million after-tax, and

loss on sale of turbine of $3.9 million after-tax.

Third quarter results include:

Constellation Energy and BGE

workforce reduction costs totaling $7.5 million after-tax, of which BGE recorded $2.0 million.

Constellation Energy

impairment of investments in qualifying facilities and domestic power projects, costs associated with exit of BGE Home merchandise stores, and impairment of real estate and international investments totaling $17.1 million after-tax.

Fourth quarter results include:

Constellation Energy and BGE

workforce reduction costs totaling $6.9 million after-tax, of which BGE recorded $1.9 million.

Constellation Energy

gains on the sale of investments of $4.5 million after-tax.

We discuss our special items in *Note 2*.

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.

2001 Quarterly Data Constellation Energy

	Revenues	Income from Operations	Earnings Applicable to Common Stock	Earnings Per Share of Common Stock
	(In millions, except per-share amounts)			
Quarter Ended				
March 31	$ 1,130.5	$ 235.0	$ 111.8	$ 0.74
June 30	826.1	171.0	75.6	0.46
September 30	1,043.4	317.5	163.6	1.00
December 31	878.8	(365.7)	(260.1)	(1.59)
Year Ended				
December 31	$ 3,878.8	$ 357.8	$ 90.9	$ 0.57

2001 Quarterly Data BGE

	Revenues	Income from Operations	Earnings Applicable to Common Stock
	(In millions)		
Quarter Ended			
March 31	$ 849.9	$ 141.1	$ 55.1
June 30	607.1	74.7	19.9
September 30	701.4	80.4	23.8
December 31	562.3	15.6	(14.7)
Year Ended			
December 31	$ 2,720.7	$ 311.8	$ 84.1

First quarter results include:

Constellation Energy

- an $8.5 million after-tax gain for the cumulative effect of adopting SFAS No. 133, and
- a gain on sale of investments of $10.0 million after-tax.

Second quarter results include:

Constellation Energy

- a gain on sale of investments of $10.3 million after-tax.

Third quarter results include:

Constellation Energy

- a gain on sale of investments of $0.5 million after-tax.

Fourth quarter results include:

Constellation Energy and BGE

- workforce reduction costs totaling $64.1 million after-tax, of which BGE recorded $34.4 million after-tax.

Constellation Energy

- contract termination related costs, and impairment losses and other costs totaling an additional $242.6 million after-tax, and
- a net loss on sale of investments and other assets of $22.7 million after-tax.

We discuss our special items in *Note 2*.

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.

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

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

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 is set forth under *Election of Constellation Energy Directors* in the Proxy Statement and is incorporated herein by reference.

The information required by this item with respect to executive officers of Constellation Energy Group, pursuant to instruction 3 of paragraph (b) of Item 401 of Regulation S-K, is set forth in 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 is set forth under *Directors' Compensation*, *Compensation Committee Interlocks and Insider Participation*, *Executive Compensation*, *Common Stock Performance Graph* and *Report of Committee on Management on Executive Compensation* in the Proxy Statement and is incorporated herein by reference.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Shareholder Matters

Equity Compensation Plan Information

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	3,769	$ 29.60	6,437
Equity compensation plans not approved by security holders	2,312	$ 29.74	4,320
Total	6,081	$ 29.65	10,757

The plans that do not require security holder approval are the Constellation Energy Group, Inc. 2002 Senior Management Long-Term Incentive Plan (Designated as Exhibit No. 10(u)) and the Constellation Energy Group, Inc. Management Long-Term Incentive Plan (Designated as Exhibit No. 10(v)). Under these plans, we may grant up to a total of 7,000,000 equity shares. We have granted stock options and performance and service-based restricted stock to officers and key employees.

The additional information required by this item is set forth under *Security Ownership* in the Proxy Statement and is incorporated herein by reference.

Item 13. Certain Relationships and Related Transactions

The additional information required by this item is set forth under *Certain Relationships and Transactions* in the Proxy Statement and is incorporated herein by reference.

Item 14. Internal Controls and Procedures

Within the 90-day period prior to the filing of this report, an evaluation was carried out under the supervision and with the participation of management, including the principal executive officers and principal financial officer of both Constellation Energy and BGE, of the effectiveness of the design and operation of their disclosure controls and procedures (as defined in Rule 13a-14(c) under the Securities Exchange Act of 1934.) Based on that evaluation, such officers have concluded that the design and operation of Constellation Energy's and BGE's disclosure controls and procedures were effective.

No significant changes were made in either Constellation Energy's or BGE's internal controls or in other factors that could significantly affect such controls subsequent to the date of their evaluation.

PART IV

Item 15. Exhibits, Financial Statement Schedules and Reports on Form 8-K

(a) The following documents are filed as a part of this Report:

1. Financial Statements:
   Report of Independent Accountants dated January 29, 2003 of PricewaterhouseCoopers LLP
   Consolidated Statements of Income Constellation Energy Group for three years ended December 31, 2002
   Consolidated Balance Sheets Constellation Energy Group at December 31, 2002 and December 31, 2001
   Consolidated Statements of Cash Flows Constellation Energy Group for three years ended December 31, 2002
   Consolidated Statements of Common Shareholders' Equity and Comprehensive Income Constellation Energy Group for three years ended December 31, 2002
   Consolidated Statements of Capitalization Constellation Energy Group at December 31, 2002 and December 31, 2001
   Consolidated Statements of Income Baltimore Gas and Electric Company for three years ended December 31, 2002
   Consolidated Balance Sheets Baltimore Gas and Electric Company at December 31, 2002 and December 31, 2001
   Consolidated Statements of Cash Flows Baltimore Gas and Electric Company for three years ended December 31, 2002
   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 in 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) in 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) in Form 8-K dated July 7, 2000, 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 in 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) in Form 10-Q dated August 13, 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 in Form 10-Q dated November 14, 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 January 24, 2003.
*3(g)	

Exhibit Number	
	Bylaws of BGE, as amended to October 16, 1998. (Designated as Exhibit No. 3 in Form 10-Q dated November 13, 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) in 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) in 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 in Form 10-Q dated August 11, 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 in Registration File No. 2-98443 as Exhibit 4(a)); as supplemented by Supplemental Indentures dated as of October 1, 1987 (Designated in Form 8-K, dated November 13, 1987, File No. 1-1910 as Exhibit 4(a)) and as of January 26, 1993 (Designated in Form 8-K, dated January 29, 1993, File No. 1-1910 as Exhibit 4(b).)
*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) in Form S-3 dated May 28, 1998, File No. 333-53767.)
*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) in Form S-3 dated May 28, 1998, File No. 333-53767.)
*4(g)	Form of Preferred Securities Guarantee (Designated as Exhibit 4(f) in Form S-3 dated May 28, 1998, File No. 333-53767.)
*4(h)	Form of Junior Subordinated Debenture (Designated as Exhibit 4(h) in Form S-3 dated May 28, 1998, File No. 333-53767.)
*4(i)	Form of Amended and Restated Declaration of Trust (including Form of Preferred Security) (Designated as Exhibit 4(c) in Form S-3 dated May 28, 1998, File No. 333-53767.)
*10(a)	Executive Annual Incentive Plan of Constellation Energy Group, Inc., as amended and restated. (Designated as Exhibit No. 10(a) to the Annual Report on Form 10-K for the year ended December 31, 2001, 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 Annual Report on Form 10-K for the year ended December 31, 2000, File Nos. 1-12869 and 1-1910.)
10(c)	Constellation Energy Group, Inc. Nonqualified Deferred Compensation Plan, as amended and restated.
*10(d)	Constellation Energy Group, Inc. Deferred Compensation Plan for Non-Employee Directors, as amended and restated. (Designated as Exhibit No. 10(d) to the Annual Report on Form 10-K for the year ended December 31, 2001, File Nos. 1-12869 and 1-1910.)
*10(e)	Baltimore Gas and Electric Company Retirement Plan for Non-Employee Directors, as amended and restated. (Designated as Exhibit No. 10(m) in Form 10-Q dated May 14, 1999, File Nos. 1-12869 and 1-1910.)

*10(f)	Summary of severance arrangement for Edward A. Crooke. (Designated as Exhibit No. 10(g) to the Annual Report on Form 10-K for the year ended December 31, 1999, File Nos. 1-12869 and 1-1910.)
*10(g)	

	Grantor Trust Agreement Dated as of January 1, 2001 between Constellation Energy Group, Inc. and Citibank, N.A. (Designated as Exhibit No. 10(g) to the Annual Report on Form 10-K for the year ended December 31, 2000, File Nos. 1-12869 and 1-1910.)
10(h)	Form of Severance Agreements between Constellation Energy Group, Inc. and the following named executive officers: Mayo A. Shattuck III, E. Follin Smith, and Frank O. Heintz.
*10(i)	Grantor Trust Agreement dated as of April 30, 1999 between Constellation Energy Group, Inc. and T. Rowe Price Trust Company. (Designated as Exhibit No. 10(e) in Form 10-Q dated May 14, 1999, File Nos. 1-12869 and 1-1910.)
*10(j)	Full Requirements Service Agreement between Constellation Power Source, Inc. and Baltimore Gas and Electric Company. (Designated as Exhibit No. 10(a) in Form 10-Q dated August 14, 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) in Form 10-Q dated 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) in Form 10-Q dated 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)	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(n)	Constellation Energy Group, Inc. Supplemental Pension Plan, as amended and restated. (Designated as Exhibit No. 10(n) 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. Senior Executive Supplemental Plan, as amended and restated. (Designated as Exhibit No. 10(o) to the Annual Report on Form 10-K for the year ended December 31, 2001, File Nos. 1-12869 and 1-1910.)
*10(p)	Constellation Energy Group, Inc. Supplemental Benefits Plan, as amended and restated. (Designated as Exhibit No. 10(p) to the Annual Report on Form 10-K for the year ended December 31, 2001, File Nos. 1-12869 and 1-1910.)
10(q)	Compensation agreements between Constellation Energy Group, Inc. and Michael J. Wallace (Attachment 1 Employment Agreement; Attachment 2 Severance Agreement.)
*10(r)	Compensation agreements between Constellation Energy Group, Inc. and Thomas V. Brooks (Attachment 1 Offer letter; Attachment 2 Equity letter; Attachment 3 Retention plan summary.) (Designated as Exhibit No. 10(r) to the Annual Report on Form 10-K for the year ended December 31, 2001, File Nos. 1-12869 and 1-1910.)
10(s)	Constellation Energy Group, Inc. Executive Long-Term Incentive Plan.
*10(t)	Constellation Energy Group, Inc. 2002 Executive Annual Incentive Plan. (Designated as Exhibit No. II in the Definitive Proxy Statement on Schedule 14A filed on April 18, 2002.)
10(u)	Constellation Energy Group, Inc. 2002 Senior Management Long-Term Incentive Plan.
10(v)	Constellation Energy Group, Inc. Management Long-Term Incentive Plan.
10(w)	Compensation agreements between Constellation Energy Group, Inc. and E. Follin Smith (Attachment 1. Offer letter; Attachment 2 Severance agreement.)
12(a)	Constellation Energy Group, Inc. and Subsidiaries Computation of Ratio of Earnings to Fixed Charges.

12(b)	Baltimore Gas and Electric Company and Subsidiaries Computation of Ratio of Earnings to Fixed Charges and Computation of Ratio of Earnings to Combined Fixed Charges and Preferred and Preference Dividend Requirements.
21	Subsidiaries of the Registrant.
23	Consent of PricewaterhouseCoopers LLP, Independent Accountants.

* Incorporated by Reference.

(b)

Reports on Form 8-K:

None.

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					
2002	$ 22.8	$ 26.4	$ 12.5 (A)	$ (19.8)(B)	$ 41.9
2001	21.3	26.5		(25.0)(B)	22.8
2000	34.8	21.1		(34.6)(B)	21.3
Valuation Allowance					
Net unrealized (gain) loss on available for sale securities					
2002	(243.7)		243.7 (C)		
2001	(33.7)		(210.0)(C)		(243.7)
2000	0.2		(33.9)(C)		(33.7)
Net unrealized (gain) loss on nuclear decommissioning trust funds					
2002	(21.0)		(26.4)(C)		(47.4)
2001	(34.7)		13.7 (C)		(21.0)
2000	(40.5)		5.8 (C)		(34.7)
Mark-to-market energy assets reserves					
2002	(43.4)		(6.5)(D)		(49.9)
2001	(54.4)		11.0 (D)		(43.4)
2000	(27.5)		(26.9)(D)		(54.4)
BGE					
Accumulated Provision for Uncollectibles					
2002	13.4	14.5		(16.4)(B)	11.5
2001	13.4	21.8		(21.8)(B)	13.4
2000	13.0	16.4		(16.0)(B)	13.4
Net unrealized (gain) loss on nuclear decommissioning trust fund					
2002					
2001					
2000	(40.5)		(1.8)(E)	42.3 (C)	

(A) Represents amounts acquired resulting from our acquisitions of NewEnergy and Alliance.

(B) Represents principally net amounts charged off as uncollectible.

(C) Represents amounts recorded in or reclassified from accumulated other comprehensive income.

(D) Represents reserves from mark-to-market energy assets credited/(charged) to revenues.

(E) Represents net unrealized gains credited to accumulated depreciation.

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 7, 2003

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 7, 2003
Principal financial and accounting officer:		
By /s/ E. F. Smith **E. F. Smith**	Senior Vice President and Chief Financial Officer	March 7, 2003
Directors:		
/s/ D. L. Becker **D. L. Becker**	Director	March 7, 2003
/s/ J. T. Brady	Director	March 7, 2003

Signature	Title	Date
J. T. Brady		
/s/ F. P. Bramble, Sr.	Director	March 7, 2003
F. P. Bramble, Sr.		
/s/ B. B. Byron	Director	March 7, 2003
B. B. Byron		
/s/ E. A. Crooke	Director	March 7, 2003
E. A. Crooke		
/s/ J. R. Curtiss	Director	March 7, 2003
J. R. Curtiss		

/s/ R. W. Gale	Director	March 7, 2003
R. W. Gale		
/s/ F. A. Hrabowski, III	Director	March 7, 2003
F. A. Hrabowski, III		
/s/ E. J. Kelly, III	Director	March 7, 2003
E. J. Kelly, III		
/s/ N. Lampton	Director	March 7, 2003
N. Lampton		
/s/ R. J. Lawless	Director	March 7, 2003
R. J. Lawless		
/s/ M. D. Sullivan	Director	March 7, 2003
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 7, 2003

By /s/ FRANK O. HEINTZ

Frank O. Heintz
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/ F. O. Heintz **F. O. Heintz**	President, Chief Executive Officer, and Director	March 7, 2003
Principal financial and accounting officer and director:		
By /s/ E. F. Smith **E. F. Smith**	Senior Vice President, Chief Financial Officer, and Director	March 7, 2003
Directors:		
/s/ M. A. Shattuck III **M. A. Shattuck III**	Director	March 7, 2003

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Certification

I, Mayo A. Shattuck III, certify that:

1. I have reviewed this annual report on Form 10-K of Constellation Energy Group, Inc.;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:

a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

March 7, 2003

/s/ MAYO A. SHATTUCK III

Mayo A. Shattuck III,
Chairman of the Board, Chief Executive Officer and President

Certification

I, E. Follin Smith, certify that:

1. I have reviewed this annual report on Form 10-K of Constellation Energy Group, Inc.;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:

a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

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a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

March 7, 2003

/s/ E. FOLLIN SMITH

E. Follin Smith,
Senior Vice President and Chief Financial Officer

Certification

I, Frank O. Heintz, certify that:

1. I have reviewed this annual report on Form 10-K of Baltimore Gas and Electric Company;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:

a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

March 7, 2003

/s/ FRANK O. HEINTZ

Frank O. Heintz,
President and Chief Executive Officer

Certification

I, E. Follin Smith, certify that:

1. I have reviewed this annual report on Form 10-K of Baltimore Gas and Electric Company;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:

a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

March 7, 2003

/s/ E. FOLLIN SMITH

E. Follin Smith,
Senior Vice President and Chief Financial Officer

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 in 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) in 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) in Form 8-K dated July 7, 2000, 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 in 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) in Form 10-Q dated August 13, 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 in Form 10-Q dated November 14, 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 January 24, 2003.
*3(g)	Bylaws of BGE, as amended to October 16, 1998. (Designated as Exhibit No. 3 in Form 10-Q dated November 13, 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) in 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) in 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 in Form 10-Q dated August 11, 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)

Dated	File No.	Designated In	Exhibit Number
*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 in Registration File No. 2-98443 as Exhibit 4(a)); as supplemented by Supplemental Indentures dated as of October 1, 1987 (Designated in Form 8-K, dated November 13, 1987, File No. 1-1910 as Exhibit 4(a)) and as of January 26, 1993 (Designated in Form 8-K, dated January 29, 1993, File No. 1-1910 as Exhibit 4(b).)
*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) in Form S-3 dated May 28, 1998, File No. 333-53767.)
*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) in Form S-3 dated May 28, 1998, File No. 333-53767.)
*4(g)	Form of Preferred Securities Guarantee (Designated as Exhibit 4(f) in Form S-3 dated May 28, 1998, File No. 333-53767.)
*4(h)	Form of Junior Subordinated Debenture (Designated as Exhibit 4(h) in Form S-3 dated May 28, 1998, File No. 333-53767.)
*4(i)	Form of Amended and Restated Declaration of Trust (including Form of Preferred Security) (Designated as Exhibit 4(c) in Form S-3 dated May 28, 1998, File No. 333-53767.)
*10(a)	Executive Annual Incentive Plan of Constellation Energy Group, Inc., as amended and restated. (Designated as Exhibit No. 10(a) to the Annual Report on Form 10-K for the year ended December 31, 2001, 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 Annual Report on Form 10-K for the year ended December 31, 2000, File Nos. 1-12869 and 1-1910.)
10(c)	Constellation Energy Group, Inc. Nonqualified Deferred Compensation Plan, as amended and restated.
*10(d)	Constellation Energy Group, Inc. Deferred Compensation Plan for Non-Employee Directors, as amended and restated. (Designated as Exhibit No. 10(d) to the Annual Report on Form 10-K for the year ended December 31, 2001, File Nos. 1-12869 and 1-1910.)
*10(e)	Baltimore Gas and Electric Company Retirement Plan for Non-Employee Directors, as amended and restated. (Designated as Exhibit No. 10(m) in Form 10-Q dated May 14, 1999, File Nos. 1-12869 and 1-1910.)
*10(f)	Summary of severance arrangement for Edward A. Crooke. (Designated as Exhibit No. 10(g) to the Annual Report on Form 10-K for the year ended December 31, 1999, File Nos. 1-12869 and 1-1910.)
*10(g)	Grantor Trust Agreement Dated as of January 1, 2001 between Constellation Energy Group, Inc. and Citibank, N.A. (Designated as Exhibit No. 10(g) to the Annual Report on Form 10-K for the year ended December 31, 2000, File Nos. 1-12869 and 1-1910.)
10(h)	Form of Severance Agreements between Constellation Energy Group, Inc. and the following named executive officers: Mayo A. Shattuck III, E. Follin Smith, and Frank O. Heintz.
*10(i)	Grantor Trust Agreement dated as of April 30, 1999 between Constellation Energy Group, Inc. and T. Rowe Price Trust Company. (Designated as Exhibit No. 10(e) in Form 10-Q dated May 14, 1999, File Nos. 1-12869 and 1-1910.)
*10(j)	Full Requirements Service Agreement between Constellation Power Source, Inc. and Baltimore Gas and Electric Company. (Designated as Exhibit No. 10(a) in Form 10-Q dated August 14, 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) in Form 10-Q dated 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) in Form 10-Q dated 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)	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(n)	Constellation Energy Group, Inc. Supplemental Pension Plan, as amended and restated. (Designated as Exhibit No. 10(n) 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. Senior Executive Supplemental Plan, as amended and restated. (Designated as Exhibit No. 10(o) to the Annual Report on Form 10-K for the year ended December 31, 2001, File Nos. 1-12869 and 1-1910.)
*10(p)	Constellation Energy Group, Inc. Supplemental Benefits Plan, as amended and restated. (Designated as Exhibit No. 10(p) to the Annual Report on Form 10-K for the year ended December 31, 2001, File Nos. 1-12869 and 1-1910.)
10(q)	Compensation agreements between Constellation Energy Group, Inc. and Michael J. Wallace (Attachment 1 Employment Agreement; Attachment 2 Severance Agreement.)
*10(r)	Compensation agreements between Constellation Energy Group, Inc. and Thomas V. Brooks (Attachment 1 Offer letter; Attachment 2 Equity letter; Attachment 3 Retention plan summary.) (Designated as Exhibit No. 10(r) to the Annual Report on Form 10-K for the year ended December 31, 2001, File Nos. 1-12869 and 1-1910.)
10(s)	Constellation Energy Group, Inc. Executive Long-Term Incentive Plan.
*10(t)	Constellation Energy Group, Inc. 2002 Executive Annual Incentive Plan. (Designated as Exhibit No. II in the Definitive Proxy Statement on Schedule 14A filed on April 18, 2002.)
10(u)	Constellation Energy Group, Inc. 2002 Senior Management Long-Term Incentive Plan.
10(v)	Constellation Energy Group, Inc. Management Long-Term Incentive Plan.
10(w)	Compensation agreements between Constellation Energy Group, Inc. and E. Follin Smith (Attachment 1. Offer letter; Attachment 2 Severance agreement.)
12(a)	Constellation Energy Group, Inc. and Subsidiaries Computation of Ratio of Earnings to Fixed Charges.
12(b)	Baltimore Gas and Electric Company and Subsidiaries Computation of Ratio of Earnings to Fixed Charges and Computation of Ratio of Earnings to Combined Fixed Charges and Preferred and Preference Dividend Requirements.
21	Subsidiaries of the Registrant.
23	Consent of PricewaterhouseCoopers LLP, Independent Accountants.

* Incorporated by Reference.