CONSTELLATION ENERGY GROUP INC
Form 10-K
March 30, 2001

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, 2000

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)

250 W. PRATT STREET BALTIMORE, MARYLAND 21201
(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 Stock 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 X No .

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. [X]

Aggregate market value of Constellation Energy Group, Inc. Common Stock, without par value, held by non-affiliates as of February 28, 2001 was approximately $6,438,511,488 based upon New York Stock Exchange composite transaction closing price.

CONSTELLATION ENERGY GROUP, INC. COMMON STOCK, WITHOUT PAR VALUE 151,188,640 SHARES OUTSTANDING ON FEBRUARY 28, 2001.

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 27, 2001.

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:

- satisfaction of all the conditions precedent to the closing on the purchase of the Nine Mile Point nuclear power plants, including obtaining all regulatory approvals,
- obtaining all regulatory approvals necessary to close on the investment by an affiliate of the Goldman Sachs Group, Inc. in our domestic merchant energy business and complete the separation of our domestic merchant energy business from our remaining businesses,
- satisfaction of all conditions precedent to the transaction with Goldman Sachs,
- general economic, business, and regulatory conditions,
- the pace and nature of deregulation nationwide (including the status of the California markets),
- competition,
- energy supply and demand,
- federal and state regulations,
- availability, terms, and use of capital,
- nuclear and environmental issues,
- weather,
- implications of the Restructuring Order issued by the Maryland PSC, including the outcome of the appeal,
- commodity price risk,
- operating our generation assets in a deregulated market without the benefit of a fuel rate adjustment clause,
- loss of revenue due to customers choosing alternative suppliers,
- higher volatility of earnings and cash flows,

- increased financial requirements of our nonregulated subsidiaries,
- inability to recover all costs associated with providing electric retail customers service during the electric rate freeze period,
- implications from the transfer of BGE's generation assets and related liabilities to nonregulated subsidiaries of Constellation Energy, including the outcome of the appeal of the Maryland PSC's Order regarding the transfer of generation assets, and
- force majeure events (events beyond our control), such as: acts of nature, changes of laws, labor strikes and work stoppages, especially as they could impact plant construction or operation.

Given these uncertainties, you should not place undue reliance on these forward looking statements. Please see the other sections of this report and our other periodic reports filed with the Securities and Exchange Commission (SEC) for more information on these factors. These forward looking statements represent our estimates and assumptions only as of the date of this report.

PART I

Item 1. Business

Overview

Constellation Energy(R) Group, Inc. (Constellation Energy) is a holding company whose businesses consist primarily of a domestic merchant energy business focused mostly on power marketing and merchant generation in North America, and Baltimore Gas and Electric Company (BGE(R)), a regulated electric and gas public utility distribution company. Constellation Energy was incorporated in Maryland on September 25, 1997. 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.

Effective July 1, 2000, electric generation was deregulated in Maryland. In anticipation of deregulation, during the first quarter of 2000, we combined our wholesale power marketing operation with our domestic plant development and operation activities to form a domestic merchant energy business. Additionally, on July 1, 2000, BGE transferred all of its generation assets and related liabilities at book value to two new nonregulated subsidiaries of our domestic merchant energy business--Calvert Cliffs Nuclear Power Plant,(TM) Inc. and Constellation Power Source Generation,(TM) Inc. We discuss the deregulation of electric generation in Item 7. Management's Discussion and Analysis--Current Issues.

We also formed a nonregulated holding company, Constellation Power Source Holdings,(TM) Inc. that oversees:

- the wholesale power marketing and risk management activities of Constellation Power Source,(TM) Inc.,
- the domestic power projects of Constellation Investments,(TM) Inc. and Constellation Power,(TM) Inc. and subsidiaries,
- the fossil and hydroelectric generating assets of Constellation Power Source Generation.

As a result of these changes, our domestic merchant energy business includes the operations of Constellation Power Source Holdings, the nuclear generating assets of Calvert Cliffs Nuclear Power Plant, Inc., and the nuclear consulting services of Constellation Nuclear,(TM) LLC.

BGE is a regulated electric and gas public utility distribution 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. BGE's electric service territory includes an area of approximately 2,300 square miles with an estimated population of 2.7 million. BGE's gas service territory includes an area of approximately 800 square miles with an estimated population of 2.0 million. There are no municipal or cooperative wholesale customers within BGE's service territory.

Our other nonregulated businesses include the:

. Latin American power projects of Constellation Power and subsidiaries,
. energy products and services of Constellation Energy Source,(TM) Inc.,
. home products, commercial building systems, and residential and small commercial electric and gas retail marketing of BGE Home Products & Services,(TM) Inc. and subsidiaries,
. a general partnership, in which BGE is a partner, of District Chilled Water General Partnership (ComfortLink(R)) that provides cooling services for commercial customers in Baltimore,
. financial investments of Constellation Investments, and
. real estate holdings and senior-living facilities of Constellation Real Estate Group,(TM) Inc.

Strategy

Customer choice and regulatory change significantly impact our business. In response to these, we regularly evaluate our strategies with two goals in mind: to improve our competitive position, and to anticipate and adapt to regulatory change. Prior to July 1, 2000, the majority of our earnings were from BGE. Going forward, prior to separating into two companies, we expect to derive almost two-thirds of our earnings from our domestic merchant energy business.

While BGE continues to be regulated and to deliver electricity and natural gas through its core distribution business, our primary growth strategies center on the nonregulated domestic merchant energy business with the objective of providing new sources of earnings growth.

On October 23, 2000, we announced three initiatives to advance our growth strategies. The first initiative is that we entered into an agreement (the "Agreement") with an affiliate of The Goldman Sachs Group, Inc. ("Goldman Sachs"). Under the terms of the Agreement, Goldman Sachs will acquire up to a 17.5% equity interest in our domestic merchant energy business, which will be consolidated under a single holding company ("Holdco"). Goldman Sachs will also acquire a ten-year warrant for up to 13% of Holdco's common stock (subject to certain adjustments). The warrant is exercisable six months after Holdco's common stock becomes publicly available. The amount of common stock which Goldman Sachs may receive upon exercise will be equal to the excess of the market price of Holdco's common stock at the time of exercise over the exercise price of $60 per share for all the stock subject to the warrant, divided by the market price. Holdco may at its option pay Goldman Sachs such excess in cash. Goldman Sachs is acquiring its interest and the warrant in exchange for $250 million in cash (subject to adjustment in certain instances) and certain assets related to our power marketing operation. At closing, Goldman Sachs' existing services agreement with our power marketing operation will terminate.

The second initiative is a plan to separate our domestic merchant energy business from our remaining businesses. The separation will create two stand-alone, publicly traded energy companies. One will be a merchant energy business engaged in wholesale power marketing and generation under the name "Constellation Energy Group" after the separation. The other will be a regional retail energy delivery and energy services company, BGE Corp., which will include BGE, our other nonregulated businesses, and our investment in Orion Power Holdings, Inc. ("Orion").

As a result of the separation, shareholders will continue to own all of Constellation Energy's current businesses through their ownership of the stock of the new Constellation Energy Group and of BGE Corp.

The third initiative is a change in our common stock dividend policy effective April 2001. In a move closely aligned with our separation plan, effective April 2001, our annual dividend is expected to be set at $.48 per share. After the separation, BGE Corp. expects to pay initial annual dividends of $.48 per share. Constellation Energy Group, as a growing merchant energy company, initially expects to reinvest its earnings in order to fund its growth plans and not to pay a dividend.

The closing of the transaction with Goldman Sachs and the separation are subject to customary closing conditions and contingent upon obtaining regulatory approvals and a Private Letter Ruling from the Internal Revenue Service regarding certain tax matters. We expect to complete the transaction and separation by mid to late 2001. At the date of this report, we received approval from the Federal Energy Regulatory Commission (FERC).

We discuss these strategic initiatives further in our Report on Form 8-K and exhibits filed with the SEC on October 23, 2000.

Currently, our domestic merchant energy business controls over 9,000 megawatts (MW) of generation. In December 2000, we announced that a subsidiary of Constellation Nuclear will purchase 1,550 MW of the 1,757 MW total generating capacity of the Nine Mile Point nuclear power plant located in Scriba, New York. The total purchase price, including

fuel, is $815 million. We discuss the planned acquisition of the Nine Mile Point power plant in more detail in Note 10 to Consolidated Financial Statements.

We also are constructing generating facilities representing 1,100 MW of natural gas-fired peaking capacity in the Mid-Atlantic and Mid-West regions which are expected to be operational by the summer of 2001. An additional 6,700 MW of natural gas-fired peaking and combined cycle production facilities in various regions of North America are scheduled for completion in 2002 and beyond. By 2005, our domestic merchant energy business expects to control approximately 30,000 MW through the construction or purchase of additional nuclear and non-nuclear generation assets and through contractual arrangements.

We decided to exit the Latin American portion of our operation as a result of our concentration on domestic merchant energy. Currently, we are actively seeking a buyer for the Latin American portion of our business and are working toward completing our exit strategy in 2001.

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

- the complete or partial separation of our transmission and distribution functions,
- mergers or acquisitions of utility or non-utility businesses, and
- sale of generation assets or one or more businesses.

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 nonrecurring items, in Note 2 to Consolidated Financial Statements. Effective with the first quarter of 2000, we revised our operating segments to reflect the realignments of our organization as discussed in the Overview section. Effective July 1, 2000, the financial results of the electric generation portion of our business are included in the domestic merchant energy business segment. Prior to that date, the financial results are included in the regulated electric segment.

	Unaffiliated Revenues			
	Domestic Merchant Energy	Regulated Electric	Regulated Gas	Other Nonregulated
2000	11%	55%	15%	19%
1999	6	60	12	22
1998	4	66	13	17

Net income(1)

	Domestic Merchant Energy	Regulated Electric	Regulated Gas	Other Nonregulated
2000	60%	29%	9%	2%
1999	16	81	10	(7)
1998	17	85	9	(11)

Total Assets

	Domestic Merchant Energy	Regulated Electric	Regulated Gas	Other Nonregulated & Corp. Items
2000	55%	28%	8%	9%
1999	13	65	9	13
1998	9	67	10	14

(1) Excludes an extraordinary charge of $66.3 million recorded in 1999 related to electric restructuring as discussed in Note 4 to Consolidated Financial Statements.

Domestic Merchant Energy Business

Introduction

Our domestic merchant energy business engages primarily in generation and power marketing in North America. We integrate our electric generation, risk management, and marketing operations to meet our customers' energy needs in the wholesale energy market.

Our goal is to become a leading merchant energy business in North America. We plan to continue our growth through the acquisition, development, and operation of power plants in our targeted markets. We also intend to capitalize on our ability to integrate power plants with the marketing of energy products and the management of market risk associated with these products. We plan to implement our strategy through the development of new power plants, acquisition of power assets competitively positioned in targeted markets, contractual arrangements for the control of generation capacity, and expansion of our marketing and risk management activities.

Currently, our domestic merchant energy business controls over 9,000 MW of generation. By 2005, our domestic merchant energy business expects to control approximately 30,000 MW through the construction or purchase of additional nuclear and non-nuclear generation assets and through contractual arrangements.

Our domestic merchant energy business experiences substantial competition from diversified energy companies, merchant generation companies, utilities, independent power producers, and power marketers. Competition is based on the price and availability of the commodities, services delivered, and the quality and reliability of services provided.

Weather conditions in the different regions of North America influence the financial results of our domestic merchant energy business. Typically, demand for electricity and its price are higher in the summer and the winter, when weather is more extreme. However, all regions of North America typically do not experience extreme weather conditions at the same time. Since the majority of our generating plants currently are located in the PJM (Pennsylvania-New Jersey-Maryland) Interconnection, our financial results are affected, to a greater extent, by weather conditions in this area. Current weather conditions also can affect the forward market price of

energy commodity and derivative contracts used by our power marketing operation that are accounted for on a mark-to-market basis. To the extent that our power marketing operation purchases and sells such contracts, our financial results could be influenced by the impact that weather conditions have on the market price of such contracts.

Delays in, or the ultimate form of, deregulation of electric generation in various states may affect our domestic merchant energy business strategy. Our domestic merchant energy business has $297.9 million invested in power projects that sell 142 MW of electricity in California under power purchase agreements as discussed in Note 10 to Consolidated Financial Statements, under the heading California Power Purchase Agreements. The counterparties to the agreements are two California investor-owned utilities. Due to various factors, including shortage of generation and the high cost of natural gas, these utilities' financial condition was severely impacted because they were paying more for power than they were allowed to recover from their customers under the deregulation plan in California. As a result, these utilities have not been able to maintain current payments for the power they purchased to meet their customers' energy needs and the credit ratings of these utilities were downgraded below investment grade. The governor and legislature of California have undertaken emergency actions to stabilize the financial condition of the two utilities by purchasing power on behalf of these utilities and pursuing legislation that should permit the utilities to pay their power costs.

In the meantime, these utilities have not been paying our California projects in full for power supplied to them from December 2000. As of the date of this report, our portion of the amount due from these utilities is approximately $42 million. While we expect to be paid for this power, we cannot predict when payment will occur or if full payment will be received. We have taken reserves in amounts we believe to be reasonable under the circumstances. On March 27, 2001, the California Public Utilities Commission issued an order for an immediate retail rate increase. Accordingly, we expect that this order should enable these utilities to pay us for all future power supplied to these utilities. However, if the ultimate resolution of the events in California prevents the collection of unpaid balances under power purchase agreements by some or all of our projects, it could have a material impact on our financial results.

In light of California's shortage of generation, we recently signed an agreement with the California Department of Water Resources for the sale of electricity beginning April 2001 through June 2003. We also signed an agreement with the California Department of Water Resources for the output of our High Desert I plant beginning July 2003 through September 2011 on a unit contingent basis (i.e., if the output is not available because the plant is not operating, there is no requirement to provide output from other sources.) We discuss our credit and other exposures related to the issues in California in Item 7. Management's Discussion and Analysis-Current Issues section.

Domestic Generation

We have operated in the nonregulated power markets since 1985. At December 31, 2000, we owned about 6,550 MW of generation capacity, and have over 9,000 MW under development, in construction, or pending acquisition. We cannot provide assurance that these projects or pending acquisitions will be completed.

Effective July 1, 2000, BGE transferred, at book value, its nuclear generating assets, its nuclear decommissioning trust fund, and related liabilities to Calvert Cliffs Nuclear Power Plant, Inc. These two units are our largest generating units, totaling 1,685 MW, and are located in PJM. 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.

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. These plants provide electricity from a variety of fuels (coal, oil, gas and water) that total 4,554 MW and are located in PJM.

In total, these generating assets represent about 6,240 MW of generation capacity with a total net book value at June 30, 2000 of approximately $2.4 billion. The output of these plants is managed by our power marketing operation. We discuss our power marketing operation in the Power Marketing section.

Constellation Power, Inc. and subsidiaries holds up to a 50% ownership interest in 28 operating domestic energy projects that consist of electric generation, 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. Projects totaling approximately $51.8 million of assets are located in the East and $419.8 million of assets are located in the West. Each electric generating plant sells its output to a local utility under long-term contracts.

The following table describes our generating and processing facilities.

Plant	Location	Installed Capacity (MW)	% Owned	O Capac
		(at December 31, 2000)		(at Decem
Generating Facilities				
Nuclear				
Calvert Cliffs	Calvert Co., MD	1,685	100.0	1
Fossil				
Steam				
Brandon Shores	Anne Arundel Co., MD	1,300	100.0	1
Herbert A. Wagner	Anne Arundel Co., MD	1,006	100.0	1
Charles P. Crane	Baltimore Co., MD	385	100.0	
Gould Street	Baltimore City, MD	104	100.0	
Riverside	Baltimore Co., MD	78	100.0	
Keystone	Armstrong and Indiana Cos., PA	1,711	21.0	
Conemaugh	Indiana Co., PA	1,711	10.6	
ACE	Trona, CA	102	22.5	
Jasmin	Kern Co., CA	33	50.0	
POSO	Kern Co., CA	33	50.0	
Total Steam		6,463		3
Combustion Turbine				
Perryman	Harford Co., MD	350	100.0	
Notch Cliff	Baltimore Co., MD	128	100.0	
Westport	Baltimore City, MD	121	100.0	
Riverside	Baltimore Co., MD	173	100.0	
Philadelphia Road	Baltimore City, MD	64	100.0	

Charles P. Crane	Baltimore Co., MD	14	100.0	
Herbert A. Wagner	Anne Arundel Co., MD	14	100.0	
Total Combustion Turbine		864		
Hydroelectric				
Safe Harbor	Safe Harbor, PA	416	66.7	
Malacha	Muck Valley, CA	32	50.0	
Total Hydroelectric		448		
Alternative				
Mammoth Lakes G-1	Mammoth Lakes, CA	8	50.0	
Mammoth Lakes G-2	Mammoth Lakes, CA	12	50.0	
Mammoth Lakes G-3	Mammoth Lakes, CA	12	50.0	
Ormesa II	Imperial Valley, CA	17	50.0	
Puna I	Hilo, HI	30	50.0	
Soda Lake I	Fallon, NV	3	50.0	
Soda Lake II	Fallon, NV	14	50.0	
Stillwater	Fallon, NV	11	50.0	
SEGS IV	Kramer Junction, CA	30	12.0	
SEGS V	Kramer Junction, CA	30	4.0	
SEGS VI	Kramer Junction, CA	30	9.0	
Chinese Station	Sonora, CA	22	50.0	
Fresno	Fresno, CA	24	50.0	
Rocklin	Placer Co., CA	24	50.0	
Central Wayne	Dearborn, MI	22	50.0	
Colver	Colver Township, PA	110	50.0	
Panther Creek	Nesquehoning, PA	83	50.0	
Sunnyside	Sunnyside, UT	51	50.0	
Total Alternative		533		
Total Generating Facilities		9,993		6

(A) Represent the generating assets that were transferred from BGE to nonregulated subsidiaries of Constellation Energy on July 1, 2000.
(B) These totals reflect our proportionate interest 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.
(C) These totals reflect our proportionate interest in the entities that own these plants.

Plant	Location	Installed Capacity (MW)	% Owned	Owned Capacity (MW)	Pr
		(at December 31, 2000)		(at December 31, 2000)	
Processing Facilities					
Gary PCI	Gary, IN	--	12.5	--	Coal Pr
A/C Fuels	Hazelton, PA	--	50.0	--	Coal Pr
PC Synfuel VA I	Appalachia, VA	--	16.7	--	Synfuel

PC Synfuel WV I	Charleston, WV	--	16.7	--	Synfuel
PC Synfuel WV II	Nettie, WV	--	16.7	--	Synfuel
PC Synfuel WV III	Mayberry, WV	--	16.7	--	Synfuel

Our domestic generation operation currently plans to construct generating facilities representing about 7,800 MW of natural gas-fired peaking capacity and combined cycle production facilities in various regions in North America in 2001 and beyond. The output of these plants will be used to meet the energy requirements of customers in the wholesale energy market. The following table describes the generating facilities that currently are under construction or are scheduled to begin construction shortly:

Plant	Location	Capacity (MW)	Type	Primary Fuel	Percent Controlled	Target In Service Date
University Park	Chicago, IL	300	Combustion Turbine	Gas	100	Summer 2001
Wolf Hills	Bristol, VA	250	Combustion Turbine	Gas	100	Summer 2001
Handsome Lake	Rockland Twp, PA	250	Combustion Turbine	Gas	100	Summer 2001
Big Sandy	Neal, WV	300	Combustion Turbine	Gas	100	Summer 2001
Rio Nogales	Seguin, TX	800	Combined Cycle	Gas	100	Summer 2002
Holland Energy	Shelby Co., IL	665	Combined Cycle	Gas	100	Summer 2002
Oleander	Brevard Co., FL	680	Combustion Turbine	Gas	100	Summer 2002
High Desert I	Victorville, CA	750	Combined Cycle	Gas	100	Summer 2003
Total		3,995				

We also have projects that currently are under development in other strategic areas that include Texas, Wisconsin, Massachusetts, Florida, and California.

Planned Acquisition

On December 12, 2000, we announced that a subsidiary of Constellation Nuclear will purchase 1,550 MW of the 1,757 MW total generating capacity of the Nine Mile Point nuclear power plant, located in Scriba, New York. The subsidiary of Constellation Nuclear will buy 100 percent of Unit 1 and 82 percent of Unit 2 for $815 million, including $78 million for fuel. The sale is expected to close in mid-2001 upon receipt of all necessary regulatory approvals. Key regulatory approvals are required from the NRC, FERC, and the New York State Public Service Commission.

The terms of the transaction include power purchase agreements, whereby we have agreed to sell 90 percent of our share of the Nine Mile Point plant's output back to the sellers for approximately 10 years at an average price of nearly $35 per megawatt-hour (MWH) over the term of the power purchase agreements on a unit contingent basis. We discuss this planned acquisition in more detail in Note 10 to Consolidated Financial Statements.

Fuel Sources

Our power plants use diverse fuel sources. At December 31, 2000, our fuel mix based on capacity owned was:

Fuel	Percentage
Nuclear	26%
Coal	42
Oil	13
Renewable and Alternative(1)	8
Dual(2)	6
Natural Gas	5

(1) Includes solar, geothermal, hydro, biomass, and waste-to-energy.
(2) Switches between natural gas and oil.

6

Nuclear

The two units at Calvert Cliffs produce electricity at a relatively low cost. As a result, the costs of replacement energy associated with outages at these units 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. We will use appropriate risk management techniques consistent with our business plan and policies in an effort to address this issue. The output at Calvert Cliffs over the past five years was as follows:

	Generation MWH	Capacity Factor
2000	13,826,046	93%
1999	13,309,306	91
1998	13,326,633	91
1997	13,133,441	90
1996	12,069,937	82

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, either in inventory or under contract, sufficient quantities of uranium to meet 100% of our requirements through 2002 and 25% through 2004.

Conversion: We have contractual commitments providing for the conversion of uranium concentrates into uranium hexafluoride that will meet approximately 75% of our requirements through 2004.

Enrichment: We have a contract with the U.S. Enrichment Corporation that provides approximately 50% of our enrichment requirements to 2004.

Fuel Assembly Fabrication: We have contracted for the fabrication of fuel assemblies for reloads required through 2013.

The nuclear fuel market is competitive and we do not anticipate any problem in meeting our requirements.

Storage of Spent Nuclear Fuel--Federal Facilities: Under the Nuclear Waste Policy Act of 1982 (the 1982 Act), we contracted with the United States Department of Energy (DOE) to place spent fuel discharged from Calvert Cliffs into a federal repository. Such facilities do not currently exist, and, consequently, must be developed and licensed. We cannot predict when such facilities will be available. However, the 1982 Act required the DOE to accept spent fuel starting in 1998. We cannot predict the ultimate cost of disposing spent fuel. However, the 1982 Act assesses a 0.1 cent (one mill) per kilowatt-hour fee on nuclear electricity generated and sold to help pay for spent fuel disposal. We estimate this fee to be approximately $13 million for Calvert Cliffs each year based on expected operating levels. Fees are deposited into the Nuclear Waste Fund. These costs are paid by Calvert Cliffs Nuclear Power Plant, Inc.

In December 1996, the DOE notified us and other nuclear utilities that it would not be able to meet the 1998 deadline for accepting spent fuel. We participated in litigation, along with 36 other utilities, against the DOE. The litigation, titled Northern States Power, et al. v. DOE, was filed January 31, 1997 in the United States Court of Appeals for the D.C. Circuit. That court has original jurisdiction under the 1982 Act. The utilities asked the court to allow them to pay fees that formerly went directly to the DOE for deposit into the Nuclear Waste Fund, into escrow instead. Among other remedies, the utilities also asked the court to force the DOE to submit a program with milestones illustrating how it would meet the deadline for accepting spent nuclear fuel, and a monthly report to allow the utilities to monitor the DOE's progress.

On November 14, 1997, the court ordered the DOE to comply with its unconditional obligation under the 1982 Act to dispose of spent fuel. The court did not grant the utilities the remedies sought, stating that adequate contractual and statutory remedies already existed. The DOE and several utilities filed separate motions for reconsideration with the court, which were denied. The DOE's request for review to the U.S. Supreme Court was also denied.

We are currently evaluating our contractual options in light of the court's decision. We cannot currently estimate the total costs we will incur as a result of the DOE's failure to meet the 1998 deadline.

Storage of Spent Nuclear Fuel--On-Site Facility: We have a license from the NRC to operate an on-site independent spent fuel storage facility. We have storage capacity at Calvert Cliffs that will accommodate spent fuel from operations through the year 2006. In addition, we can expand our temporary storage capacity to meet future requirements until federal storage is available.

Cost for Decommissioning Uranium Enrichment Facilities: The Energy Policy Act of 1992 (the 1992 Act) contains provisions requiring domestic nuclear utilities to contribute to a fund for decommissioning and decontaminating the DOE's uranium enrichment

facilities. These contributions are payable by BGE generally over a fifteen-year period with escalation for inflation and are based upon the amount of uranium enriched by the DOE for each utility through 1992. The 1992 Act provides that these costs are recoverable through BGE's service rates. Information about the cost of decommissioning is discussed in Note 1 to Consolidated Financial Statements.

Cost for Decommissioning Calvert Cliffs: Calvert Cliffs Nuclear Power Plant, Inc., is liable for the decommissioning costs of Calvert Cliffs and costs associated with the on-site independent spent fuel storage facilities. On July 1, 2000, BGE transferred the trust fund established to decommission Calvert Cliffs and the on-site spent fuel storage facility to Calvert Cliffs Nuclear Power Plant, Inc. Under the Restructuring Order issued by the Maryland Public Service Commission (Maryland PSC), BGE is authorized to collect from customers $520 million in 1993 dollars, adjusted for inflation, for the decommissioning of Calvert Cliffs. BGE is passing the amount collected from its customers to Calvert Cliffs Nuclear Power Plant, Inc. We must refund any amounts collected from BGE customers at the time of decommissioning that is in excess of the amount authorized to be collected by the Restructuring Order. We discuss the Restructuring Order in the Electric Regulatory Matters and Competition--Restructuring Order section.

Coal

We get most of our coal under supply contracts with mining operators, and we get the rest through spot purchases. We believe that we will be able to renew supply contracts as they expire or enter into similar contracts with other coal suppliers. Our primary coal-burning facilities have the following requirements:

	Annual Coal Requirement (tons)	Special Coal Restrictions
Brandon Shores Units 1 and 2 (combined)	3,500,000	Sulfur content less than 0.8%
Crane Units 1 and 2 (combined)	800,000	Low ash melting temperature
Wagner Units 2 and 3 (combined)	1,000,000	Sulfur content no more than 1%

Coal deliveries to these facilities are made by rail and barge. The coal we use is produced mostly from mines located in central and northern Appalachia.

The majority of the annual coal requirements for the Keystone plant are under contract from Rochester and Pittsburgh Coal Company. The remainder of the Keystone plant and all of the Conemaugh plant annual coal requirements are purchased from local suppliers on the open market. The sulfur restrictions on coal are approximately 2.5% for the Keystone plant and approximately 3.5% 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%.

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 directly into our barges from the suppliers' Baltimore Harbor marine terminal for distribution to the various generating plant locations. We also require approximately 5,000,000 to 6,000,000 gallons of distillates (No. 2 oil and kerosene) annually. 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 to meet our requirements.

Gas

We purchase natural gas and transportation, as necessary, for electric generation at certain plants and to provide ignition and banking 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. We believe that we will be able to obtain adequate quantities of gas to meet our requirements.

Power Marketing

Constellation Power Source, Inc. (CPS), formed in 1997, provides power marketing and risk management services to wholesale customers in North America through the purchase and sale of electric power, other energy commodities and related derivative contracts. CPS was ranked by Power Markets Weekly as a top ten power marketer in the United States based on MWH sold in 2000.

CPS purchases electric power by several methods, including:

. through bilateral agreements with third parties,
. from regional power pools, or
. from affiliates in the domestic merchant energy business.

CPS sells the electric power it purchases to customers such as utilities, municipalities, cooperatives and other resellers, structuring the transactions to meet each customer's diverse needs.

CPS supplies the standard offer electric supply service to BGE as discussed in Item 7. Management's Discussion and Analysis--Current Issues and to several distribution utilities in New England. CPS sold 162,349,997 MWH of electric power in 2000, including sales to BGE, 69,787,986 MWH in 1999, and 27,608,080 MWH in 1998, its first full year of operation. Excluding BGE, no one customer or small group of customers accounts for a material portion of CPS' electric power purchases or sales.

CPS' goal is to be a premier provider of energy products and risk management services to wholesale customers throughout North America. To accomplish this goal, CPS focuses its activities on structuring transactions to meet customers' specific energy needs and providing risk management services to wholesale customers. This includes optimizing the value of generating assets owned by affiliates. We believe that our energy marketing and risk management expertise and strong risk controls are essential to maximize the value of our generating assets in the highly competitive wholesale energy market. We expect CPS to continue to establish itself as a leading national merchant energy company by leveraging its marketing and risk management expertise to pursue opportunities presented by the continuing deregulation of the North American energy markets.

CPS engages in trading activities in order to manage its portfolio of energy purchases and sales to customers through structured transactions, 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 it to purchase or sell energy commodities in the future,
.swap agreements, which require payments to or from counterparties based upon the differential between two prices for a predetermined contractual (notional) quantity,
.options 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 CPS 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 market prices; and hedge fuel requirements at power generation facilities.

CPS' trading activities expose it to market and credit risk. CPS monitors and controls its risk exposure through separate but complementary financial, operational, and credit reporting systems. Our Board of Directors establishes parameters for the risks that CPS undertakes, which are monitored daily by management. In addition, CPS maintains a segregation of duties, with credit review and risk monitoring functions performed by groups that are independent from revenue producing groups.

CPS is exposed to the risk that fluctuating market prices may adversely affect its, or our, financial results. For additional information on market and credit risk, see Item 7. Management's Discussion and Analysis--Market Risk.

Nuclear Consulting Services

Constellation Nuclear Services, Inc. (CNS) was formed in 1999 to provide nuclear license renewal related services to the utility industry. In addition to nuclear license renewal, CNS also provides plant aging mitigation services including: spent fuel management, dry fuel storage, steam generation life optimization, and project management and engineering.

BGE

BGE is a regulated electric and gas public utility distribution company with a service territory that covers the City of Baltimore and all or part of ten counties in Central Maryland. BGE's electric service territory includes an area of approximately 2,300 square miles with an estimated population of 2.7 million. BGE's gas service territory includes an area of approximately 800 square miles with an estimated population of 2.0 million. Our electric and gas revenues come from many customers--residential, commercial, and industrial. In 2000, our largest electric customer provided 2.4% of our total electric revenues. In 2000, our largest gas customer provided 0.7% of our total gas revenues. As discussed below, BGE's regulated electric business was significantly impacted by the July 1, 2000 implementation of customer choice in Maryland.

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.

Electric Business

Electric Regulatory Matters and Competition

Restructuring Order

On April 8, 1999, Maryland enacted the Electric Customer Choice and Competition Act of 1999 (the "Act") and accompanying tax legislation that significantly restructured Maryland's electric utility industry and modified the industry's tax structure. In the Restructuring Order discussed below, the Maryland PSC addressed the major provisions of the Act. The accompanying tax legislation is discussed in detail in Note 4 to Consolidated Financial Statements.

On November 10, 1999, the Maryland PSC issued a Restructuring Order that resolved the major issues surrounding electric restructuring, accelerated the timetable for customer choice, and addressed the major provisions of the Act. The Restructuring Order also resolved the electric restructuring proceeding (transition costs, customer price protections, and unbundled rates for electric services) and a petition filed in September 1998 by the Office of People's Counsel to lower our electric base rates. The major provisions of the Restructuring Order are discussed in Note 4 to Consolidated Financial Statements.

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

- All customers, except a few commercial and industrial companies that have signed contracts with BGE, can choose their electric energy supplier. BGE will provide a standard offer service for customers that do not select an alternative supplier. In either case, BGE will continue to deliver electricity to all customers in areas traditionally served by BGE.

- BGE reduced residential base rates by approximately 6.5%, on average about $54 million a year. These rates will not change before July 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. In total, these generating assets represent about 6,240 megawatts of generation capacity with a total net book value at June 30, 2000 of approximately $2.4 billion.
- 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. Also, Constellation Power Source Generation issued approximately $366 million in unsecured promissory notes to BGE. Repayments of the notes by Constellation Power Source Generation will be used exclusively to service the current maturities of certain BGE long-term debt.
- BGE transferred equity associated with the generating assets to Calvert Cliffs Nuclear Power Plant, Inc. and Constellation Power Source Generation.
- The fossil fuel and nuclear fuel inventories, materials and supplies, and certain purchased power contracts of BGE were also assumed by these subsidiaries.

Standard Offer Service

Effective July 1, 2000, BGE provides standard offer service to customers at fixed rates over various time periods during the transition period through June 30, 2006 for those customers that do not choose an alternate supplier. In addition, the electric fuel rate was discontinued effective July 1, 2000. CPS provides BGE with the energy and capacity required to meet its standard offer service obligations for the first three years of the transition period. Thereafter, BGE will competitively bid the energy and capacity for those customers electing to receive energy from BGE. We are evaluating alternatives to minimize the market risk after June 30, 2003. We discuss the market risk of our regulated electric business in more detail in Item 7. Management's Discussion and Analysis--Market Risk.

Prior to July 1, 2000, BGE deferred (included as an asset or liability on the Consolidated Balance Sheets and excluded from the Consolidated Statements of Income) the difference between its actual costs of fuel and energy and what it collected from customers under the fuel rate in a given period. Effective July 1, 2000, the fuel rate clause was discontinued under the terms of the Restructuring Order. In September 2000, the Maryland PSC approved the collection of the $54.6 million accumulated difference between BGE's 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. BGE is collecting this accumulated difference from customers over the twelve-month period beginning October 2000.

BGE's electric transmission and distribution business continues to be regulated by the Maryland PSC although electric delivery rates are fixed until June 30, 2004 for industrial and commercial customers and until June 30, 2006 for residential customers. However, electric transmission and distribution utilities are facing competition from alternative energy sources that include on-site generation and cogeneration projects. In future years, electric transmission and distribution utilities could face competition from emerging technologies that include fuel cells and solar panels.

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 2000 peak load from active load management was approximately 425 MW. The potential reduction in the summer 2001 peak load from active load management is expected to be approximately425 MW.

Transmission Facilities

Our transmission facilities are connected to those of neighboring utility systems as part of the PJM. Under the PJM agreement, we use the interconnected facilities for substantial energy interchange and capacity transactions as well as emergency assistance.

In December 1999, FERC issued Order 2000, amending its regulations under the Federal Power Act to advance the formation of Regional Transmission Organizations (RTOs). The regulations require that each public utility that owns, operates, or controls facilities for the transmission of electric energy in interstate commerce make certain filings with respect to forming and participating in a RTO. FERC also identified the minimum characteristics and functions that a transmission entity must satisfy in order to be considered a RTO.

According to Order 2000, a public utility that is a member of an existing transmission entity that has been approved by FERC as in conformance with the Independent System Operator (ISO) principles set forth in the FERC Order No. 888, such as BGE through its membership in the PJM, was required to make a filing no later than January 15, 2001. PJM and the joint transmission owners, including BGE, made that filing on October 11, 2000. That filing explained the extent to which PJM met the minimum characteristics and functions of a RTO, and explained its plans with respect to conforming to these characteristics and functions.

As a member of PJM, an existing ISO, BGE does not expect to be materially impacted by Order 2000. However, we are appealing two requirements of Order 2000 whereby:

- we would have to go through PJM to make a filing with FERC to change our transmission rates, and
- we would have to transfer operational control of our transmission facilities to PJM.

The U.S. Supreme Court agreed to hear an appeal by others of FERC Order 888. We cannot predict the outcome of this appeal or the impact on BGE at this time.

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Electric Operating Statistics

	Year Ended December 31,				
	2000(A)	1999	1998	1997	1996
Revenues (In Millions)					

Residential	$ 922.6	$ 975.2	$ 948.6	$ 932.5	$ 958.7
Commercial	926.2	939.3	912.9	892.6	861.3
Industrial	203.6	204.3	211.5	211.9	207.6
System Sales	$2,052.4	$2,118.8	$2,073.0	$2,037.0	$2,027.6
Sales (In Thousands)-- MWH:					
Residential	11,675	11,349	10,965	10,806	11,243
Commercial	14,042	13,565	13,219	12,718	12,591
Industrial	4,476	4,350	4,583	4,575	4,596
System Sales	30,193	29,264	28,767	28,099	28,430
Customers (In Thousands)					
Residential	1,033.4	1,021.4	1,009.1	1,001.0	995.2
Commercial	108.9	107.7	106.5	105.9	104.5
Industrial	5.0	4.7	4.6	4.5	4.3
Total	1,147.3	1,133.8	1,120.2	1,111.4	1,104.0

(A) Electric operating results reflect generation function as part of regulated operations through June 30, 2000.

Gas Business

Gas Regulatory Matters and 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. However, the delivery of gas continues to be regulated by the Maryland PSC.

We buy all gas that we resell directly from various suppliers (rather than pipeline companies) and arrange separately for transportation and storage. Alternatively, we can transport gas for our customers. We also participate in the interstate markets, by releasing pipeline capacity or bundling pipeline capacity with gas for off-system sales.

We provide all of our customers with the option for delivery service across our distribution system so that they may make direct purchase and transportation arrangements with suppliers and pipelines. In addition to the delivery service, we also provide these customers with meter readings, billing, emergency response, regular maintenance, and balancing.

Approximately 57% of the gas on our distribution system is for customers using delivery service. We charge all our delivery service 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 sales.

Delivery service customers may choose to purchase gas from several different suppliers, including our subsidiary, BGE Home Products & Services, Inc. The basis of competition for delivery service customers is primarily commodity price.

As part of our response to the increase in competition in the natural gas business, earnings from off-system gas sales and capacity release revenues are shared between shareholders and customers. Off-system gas sales are low-margin direct sales of gas to wholesale suppliers of natural gas outside our service territory. We make these sales as part of a program to balance our supply of, and cost of, natural gas. In addition, we have a market based rates incentive mechanism for gas we sell on our system. 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.

On November 17, 1999, BGE filed an application with the Maryland PSC to increase its gas base rates. The Maryland PSC authorized a $6.4 million annual increase in our gas base rates effective June 22, 2000.

Gas Operations

We distribute natural gas purchased directly from many producers and marketers. We have transportation and storage agreements as shown below. These agreements are on file with the FERC. The gas is transported to our city gates, under various transportation agreements, by:

- Columbia Gas Transmission Corporation,
- Dominion Transmission Inc., and
- Transcontinental Gas Pipe Line Corporation.

To transport gas from the pipelines that supply gas to the pipelines that are connected to our city gates as mentioned above, we also have transportation capacity under contract with:

- Texas Gas,
- Columbia Gulf Transmission Company, and
- ANR Pipeline Company.

We have storage service agreements with:

- Columbia Gas Transmission Corporation,
- Dominion Transmission Inc., and
- ANR Pipeline Company.

Our current pipeline firm transportation entitlements to serve our firm loads are 284,053 DTH per day during the winter period and 259,053 DTH per day during the summer period. We use the firm transportation capacity to move gas from the Gulf of Mexico, Louisiana, south central regions of Texas, and Canada to our city gates. We can arrange short-term contracts or exchange agreements with other gas companies in the event of short-term emergencies.

We have three market area storage contracts to manage weather sensitive gas demand during the winter 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 1,000,000 DTH and a planned daily capacity of 287,988 DTH, and
- a propane air facility with a mined cavern with a total storage capacity equivalent to 500,000 DTH and a planned 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 operation of our liquefied natural gas facility during winter emergencies.

Gas Operating Statistics

	Year Ended December 31,				
	2000	1999	1998	1997	1996
Gas Output (In Thousands) -- DTH:					
Purchased........................	48,518	49,082	47,972	62,988	70,260
LNG Withdrawn from Storage.......	874	463	268	484	904
Produced.........................	261	486	46	541	784

Total Output	49,653	50,031	48,286	64,013	71,948
Delivery service gas (A)	67,658	59,494	55,608	52,629	45,964
Off-system sales (B)	22,456	15,543	16,724	14,759	9,968
Total	139,767	125,068	120,618	131,401	127,880
Peak Day Sendout (DTH)	795,700	727,800	658,359	765,011	708,966
Capability on Peak Day (DTH)	825,100	836,600	833,000	870,000	870,000
Revenues (In Millions)					
Residential					
Excluding Delivery Service	$ 328.4	$ 298.1	$ 279.2	$ 321.7	$ 320.1
Delivery Service	23.5	11.5	4.9	0.5	--
Commercial					
Excluding Delivery Service	97.9	79.3	75.6	113.5	125.1
Delivery Service	25.8	24.4	19.4	12.9	7.2
Industrial					
Excluding Delivery Service	10.9	8.2	8.0	11.4	17.1
Delivery Service	16.3	16.1	16.0	17.2	14.6
System sales	502.8	437.6	403.1	477.2	484.1
Off-system sales	101.0	42.9	40.9	37.5	26.6
Other	7.8	7.6	7.1	6.9	6.6
Total	$ 611.6	$ 488.1	$ 451.1	$ 521.6	$ 517.3
Sales (In Thousands) -- DTH:					
Residential					
Excluding Delivery Service	34,561	34,272	33,595	39,958	43,784
Delivery Service	9,209	4,468	1,890	205	--
Commercial					
Excluding Delivery Service	13,186	11,733	11,775	18,435	22,698
Delivery Service	22,921	20,288	16,633	12,964	8,755
Industrial					
Excluding Delivery Service	1,386	1,367	1,412	2,016	2,887
Delivery Service	32,382	33,118	34,798	38,791	36,201
System sales	113,645	105,246	100,103	112,369	114,325
Off-system sales	22,456	15,543	16,724	14,759	9,968
Total	136,101	120,789	116,827	127,128	124,293
Customers (In Thousands)					
Residential	553.7	543.5	532.5	524.5	516.5
Commercial	40.1	39.9	39.6	39.3	38.9
Industrial	1.4	1.3	1.3	1.3	1.3
Total	595.2	584.7	573.4	565.1	556.7

For the periods presented, we achieved an all-time peak day sendout of 795,700 DTH on January 17, 2000.

(A) Delivery service gas is gas purchased by customers directly from suppliers for which we receive a fee for transportation through our system.

(B) Off-system sales are low-margin sales to wholesale suppliers of natural gas outside our service territory (beginning first quarter 1996).

We discuss these programs further in the Gas Regulatory Matters and Competition section.

Franchises

We have 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. All such franchises, other than the gas franchises in Manchester, Hampstead, Perryville, Sykesville, Havre de Grace, Mt. Airy, and Montgomery and Frederick Counties, are unlimited

as to time. The gas franchises for these jurisdictions expire at various times from 2015 to 2087, except for Havre de Grace which has the right, exercisable at twenty-year intervals from 1907, to purchase all of our gas properties in that municipality. Conditions of the franchises are satisfactory.

Other Nonregulated Businesses

International Projects

At December 31, 2000, Constellation Power, Inc. had invested about $255.9 million in 10 power projects in Latin America. These investments include:

- a 51% interest in a Panamanian electric distribution company by an investment group in which subsidiaries of Constellation Power hold an 80% interest,
- existing electric generation facilities in Guatemala and Bolivia, and
- an investment in an Energy Fund that has investments in Argentina, Brazil, and Bolivia.

In December 1999, we decided to exit the Latin American portion of our business as a result of our concentration on domestic merchant energy. Currently, we are actively seeking a buyer for the Latin American portion of our business and are working toward completing our exit strategy in 2001.

Energy Products and Services

Constellation Energy Source, Inc. offers energy products and services designed primarily to provide solutions to the energy needs of commercial and industrial customers. These energy products and services include:

- a full range of heating, ventilation, air conditioning, and energy services,
- energy consulting and power-quality services,
- services to enhance the reliability of individual electric supply systems, and
- customized financing alternatives.

Home Products, Commercial Building Systems, and Electric and Gas Retail Marketing

BGE Home Products & Services, Inc. and subsidiaries offer services to residential, commercial, and industrial customers. These services include:

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

ComfortLink

ComfortLink provides cooling services using a central chilled water distribution system to commercial customers in Baltimore.

Financial Investments

Constellation Investments, Inc. engages in financial investments, including:

- marketable securities, and
- financial limited partnerships.

Real Estate and Senior-Living Facilities

Constellation Real Estate Group, Inc. develops, owns, and manages real estate and senior-living facilities, including:

- land under development in the Baltimore-Washington corridor,
- a mixed-use planned-unit development,
- senior-living facilities, and
- an equity interest in Corporate Office Properties Trust (COPT), a real estate investment trust.

We describe the real estate business and the COPT transaction further in Item 7. Management's Discussion and Analysis and Note 3 to Consolidated Financial Statements.

We consider market demand, interest rates, the availability of financing, and the strength of the economy in general when making decisions about our real estate projects. If we were to decide to sell our real estate projects, we could have write-downs. In addition, if we were to sell our real estate projects in the current market, we would have losses, which could be material, although the amount of the losses is hard to predict. Depending on market conditions, we could also have material losses on any future sales.

Consolidated Capital Requirements

Our business requires a great deal of capital. Our total capital requirements for 2000 were $1,877 million. Of this amount, $1,125 million was used in our nonregulated businesses and $752 million was used in our utility operations. We estimate our total capital requirements for the years 2001 through 2003 to be:

- $2,529 million in 2001,
- $1,863 million in 2002, and
- $2,626 million in 2003.

We continuously review and change our capital expenditure programs, so actual expenditures may vary from the estimates for the years 2001 through 2003.

We discuss our capital requirements further in Item 7. Management's Discussion and Analysis-- Capital Resources.

Environmental Matters

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

- air quality,
- water quality,
- chemical and waste management and disposal, and
- other environmental matters.

Some of the regulations require substantial expenditures for additions to some of our older generating plants and the use of more low-sulfur fuels. We cannot precisely estimate the total effect on our facilities and operations of current and future environmental regulations and standards. However, our capital expenditures (excluding allowance for funds used during construction) were approximately $126 million during the five-year period 1996-2000 to comply with existing environmental standards and regulations, and we estimate that the future incremental capital expenditures (excluding allowance for funds used during construction) necessary to comply with existing environmental standards and regulations will be approximately:

- $88 million in 2001,
- $40 million in 2002, and
- $7 million in 2003.

Clean Air

The Federal Clean Air Act regulates health and welfare standards for concentrations of air pollutants. Under this Act, each state must set limits on all major sources of these pollutants in its state so that the standards are not exceeded. We have certain emission or operational limits which include limits on sulfur content in fuel, releases of nitrogen oxides (NOx) emissions, release of particulate matter, facility design, or operational parameters imposed by either a federal or state agency on our generating units for the purpose of air quality control and compliance with existing air quality regulations.

The Clean Air Act of 1990 contains two titles designed to reduce emissions of sulfur dioxides and NOx from certain electric generating stations--Title IV and Title I.

Title IV addresses emissions of sulfur dioxides. For our older plants, we meet the requirements of Title IV through a combination of switching fuels and allowance trading. For newer plants, we meet the requirements of Title IV primarily through facility design, and operational and pollution controls.

Title I addresses emissions of NOx. The Maryland Department of the Environment (MDE) has issued regulations, effective October 18, 1999, which required up to 65% NOx emissions reductions by May 1, 2000. We entered into a settlement agreement with the MDE since we could not meet this deadline. Under the terms of the settlement agreement, we will install emissions reduction equipment at two sites by May 2002. In the meantime, we are taking steps to control NOx emissions at our generating plants.

The Environmental Protection Agency (EPA) issued a final rule in September 1998 that requires up to 85% NOx emissions reductions by 22 states (including Maryland and Pennsylvania). Maryland and Pennsylvania expect to meet the requirements of the rule by 2003. The emissions reduction equipment installations discussed above will allow us to meet these requirements in Maryland. The generating plants in Pennsylvania also will install emissions reduction equipment by 2003 to meet the 85% reduction requirements.

We currently estimate that the additional controls needed at our generating plants to meet the MDE's 65% NOx emission reduction requirements will cost approximately $150 million. Through December 31, 2000, we have spent approximately $115 million to meet the 65% reduction requirements. We estimate the additional cost for the EPA's 85% reduction requirements to be approximately $90 million by 2003. These amounts will be paid by our domestic merchant energy business.

In July 1997, the EPA published new National Ambient Air Quality Standards for very fine particulates and revised standards for ozone attainment. In 1999, these new standards were successfully challenged in court. The EPA appealed

the 1999 court rulings to the Supreme Court. In February 2001, the Supreme Court upheld EPA's authority to issue the standards. However, the Supreme Court sent the case back to the lower court and EPA for further proceedings on implementation issues related to the revised ozone standard. The lower court will also address remaining challenges to the fine particulate standard. While these standards may require increased controls at the fossil generating plants in the future, implementation, if required, would 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.

In December 2000, the EPA issued a determination that coal-fired power plant mercury emissions will be controlled. Final regulations are expected to be issued in 2004 with controls required by 2007. The costs of these controls cannot be estimated at this time since the level of control or systems to implement them have not yet been established.

We received letters from the EPA requesting us to provide certain information under Section 114 of the federal Clean Air Act regarding some of our electric generating 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. In general, such standards can require the installation of additional air pollution control equipment upon the major modification of an existing plant. We have provided the EPA the requested information. We believe our generating plants have been operated in accordance with the Clean Air Act and the rules implementing the Clean Air Act. However, we cannot estimate the impact of this inquiry on our generating plants, and our financial results, at this time.

Water

Each state regulates the discharge of process wastewater and certain stormwater discharges into its waters under the National Pollutant Discharge Elimination System permit program. This program was established as part of the Federal Clean Water Act. At the present time, we have the required permits under the program for all of our electric generating plants.

The water quality regulations require us to, among other things, define procedures to determine compliance with each state's water quality standards. These procedures require extensive studies involving sampling and monitoring of the waters around affected generating plants. Each state may require changes in plant operations. We continually perform studies to determine whether any changes will be necessary to comply with these regulations.

Waste Disposal

The EPA has regulations for implementing the portions of the Resource Conservation and Recovery Act that deal with the management of hazardous wastes. These regulations, and the Hazardous and Solid Waste Amendments of 1984, identify certain spent materials as hazardous wastes and establish standards and requirements for those who generate, transport, store, or dispose of such wastes. States have adopted regulations governing the management of hazardous wastes that are similar to the EPA regulations and in some cases more stringent. We have procedures in place to comply with all applicable EPA and state regulations governing the management of hazardous wastes. Some high volume utility wastes, such as coal fly ash and bottom ash, are exempt from these regulations. We currently use all of our coal fly ash and bottom ash in a manner consistent with federal, state, and local laws and regulations. These include the use of ash as structural fill material, and recycled material that can be sold to the construction industry for a number of other approved uses. We also deposit ash in landfills. We continue to evaluate various recycling opportunities for our coal fly ash and bottom ash.

The Federal Comprehensive Environmental Response, Compensation and Liability Act (Superfund statute) establishes liability for the cleanup of hazardous wastes that contaminate the soil, water, or air. Those who generated, transported, or deposited the waste at the contaminated site are each jointly and severally liable for the cost of the cleanup, as are the current property owner and the owner when the contamination occurred. Many states have implemented laws similar to the Superfund statute.

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.

In the early 1970s, we 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 us and nine other utilities that we are considered potentially responsible parties (PRPs) with respect to the cleanup of the site. We, along with the other PRPs,

submitted a remedial investigation and feasibility study (RI/FS) to the EPA on October 14, 1994, and the EPA issued its Record of Decision (ROD) on December 31, 1997. On June 26, 1998, the EPA ordered us, the other utility PRPs, and the owner/operator to implement the requirements of the ROD. The utility PRPs are currently conducting the remedial design. Based on the ROD, our share of the reasonably possible cleanup costs, estimated to be approximately 15.47%, could be as much as $2.3 million higher than amounts we have recorded as a liability on our Consolidated Balance Sheets.

On October 16, 1989, the EPA filed a complaint in the U.S. District Court for the District of Maryland under the Superfund statute against us and seven other defendants to recover past and future expenditures associated with the cleanup of a site located at Kane and Lombard Streets in Baltimore. The State of Maryland filed a similar complaint in the same case and court on February 12, 1990. The complaints alleged that we arranged for our coal fly ash to be deposited on the site. The Court dismissed these complaints in November 1995. The MDE began additional investigation on the remainder of the site for the EPA, but never completed the investigation. We, along with three other defendants, agreed to complete the RI/FS of groundwater contamination around the site in a July 1993 consent order. The remedial action, if any, for the remainder of the site will not be selected until these investigations are concluded. Therefore, we cannot estimate the total amount, or our share, of the site cleanup costs.

From 1985 until 1989, we shipped waste oil and other materials to the Industrial Solvents and Chemical Company in York County, Pennsylvania for disposal. The Pennsylvania Department of Environmental Protection (PADEP) subsequently investigated this site and found it to be heavily contaminated by hazardous wastes. The PADEP notified us on August 15, 1990, that approximately 1,000 other entities and we are PRPs with respect to the cost of all remedial activities to be conducted at the site. The PRPs have performed waste characterization, removed and disposed of all tanks and drums of waste, completed a RI/FS at the site, and installed public water lines. In 1998, PADEP notified BGE and other PRPs of the final remedy and requested the installation of additional public water lines. In 1999, the PRPs installed the water lines and PADEP approved the final report in March 2000. We have no further obligations under the consent orders at the site.

In December 1995, the EPA notified us that we are one of approximately 650 parties that may have incurred liability under the Superfund statute for shipments of hazardous wastes to a site in Denver, Colorado known as the RAMP Industries site. We, through our disposal vendor, shipped a small amount of low level radioactive waste to the site between 1989 and 1992. The site, which was found to have been operated improperly, was closed in 1994. That same year, the EPA began cleaning up the site by removing drums of radioactive and hazardous mixed wastes. BGE accepted a settlement offer from EPA in August 1999, whereby BGE will pay an immaterial amount to resolve its liability at this site. The consent order will be finalized in 2001.

In September 1996, we received an information request from the EPA about the Drumco Drum Dump Site, located in the Curtis Bay area of Maryland. This site was the subject of an emergency drum removal action in 1991, due to a concern about hazardous substances leaking from drums and posing a threat to human health and the environment. According to EPA documents, approximately $2 million was spent on the drum removal action. To our knowledge, no long-term remediation is planned for this site. In addition, we understand that the EPA has sent information requests to approximately 17 other parties. Our records indicate that we sold empty drums to Drumco, Inc. from approximately 1983-1990. Although our potential liability cannot be estimated, we do not expect such liability to be material based on our records showing that we sold only empty storage drums to Drumco, Inc.

On July 12, 1999, the EPA notified us, along with 19 other entities, that we may be a potentially responsible party at the 68th 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 our records showing that we did not send waste to the site.

In the early part of the century, predecessor gas companies (which were later merged into BGE) manufactured coal gas for residential and industrial use. 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. We are coordinating an investigation of some of these former manufacturing sites, and determining what, if any, remedial action may be required by MDE.

In late December 1996, we signed a consent order with the MDE that requires us to implement remedial action plans for contamination at and around the Spring Gardens site, located in Baltimore,

Maryland. We submitted the required remedial action plans and they have been approved by the MDE. Based on the remedial action plans, the costs we consider to be probable to remedy the contamination are estimated to total $47 million in nominal dollars (including inflation). We have recorded these costs as a liability on our Consolidated Balance Sheets and have deferred these costs, net of accumulated amortization and amounts we recovered from insurance companies, as a regulatory asset. We discuss this further in Note 5 to Consolidated Financial Statements. Through December 31, 2000, we have spent approximately $35 million for remediation at this site.

We are also required by accounting rules to disclose additional costs we consider to be less likely than probable, but still "reasonably possible" of being incurred at these sites. Because of the results of studies at these sites, it is reasonably possible that these additional costs could exceed the amount we recognized by approximately $14 million in nominal dollars ($7 million in current dollars, plus the impact of inflation at 3.1% over a period of up to 36 years).

Employees

As of December 31, 2000, we employed about 7,800 people.

Item 2. Properties

We lease several properties that are used for Constellation Energy's headquarters, various offices, and services. We own BGE's principal headquarters building in downtown Baltimore.

We describe our electric generation properties in the Domestic Merchant Energy Business section.

We own the following propane air and liquefied natural gas facilities:

. a liquefied natural gas facility for the liquefaction and storage of natural gas with a total storage capacity of 1,000,000 DTH and a planned daily capacity of 287,988 DTH, and
. a propane air facility with a mined cavern with a total storage capacity of 500,000 DTH and a planned daily capacity of 85,000 DTH.

We also have 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.

property.

All of BGE's property and the electric generation assets that were transferred by BGE to our domestic merchant energy business as part of deregulation, are subject to the lien of BGE's mortgage securing its mortgage bonds.

Item 3. Legal Proceedings

In the normal course of business, we are involved in various legal proceedings. We discuss our legal proceedings in Note 10 to Consolidated Financial Statements.

Item 4. Submission of Matters to Vote of Security Holders
Not applicable.

Executive Officers of the Registrant

BGE meets the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K for a reduced disclosure format. Accordingly, the executive officers of BGE are not presented below.

Executive Officers of Constellation Energy Group at the date of this report are:

Name	Age	Present Office	Other Offices or Positions Held During Past Five Years
Christian H. Poindexter	62	Chairman of the Board and Chief Executive Officer (A) (Since formation of Constellation Energy Group as the holding company on April 30, 1999; since March 1, 1998 for BGE)	Chairman of the Board, President, and Chief Executive Officer--Constellation Energy and BGE
Edward A. Crooke	62	Vice Chairman (B) (Since October 20, 2000)	Vice Chairman--Constellation Energy, Chairman of the Board, President and Chief Executive Officer--Constellation Enterprises, Inc., Chairman of the Board--Constellation Holdings, Inc., and President and Chief Operating Officer--BGE
Eric P. Grubman	43	Co-President (Since October 20, 2000)	Partner and Managing Director, Co-Head of Energy & Power--Goldman Sachs & Co.
Charles W. Shivery	55	Co-President (Since October 20, 2000) President and Chief Executive Officer, Constellation Power Source Holdings, Inc. (since July 1, 2000), CEO and President, Constellation Enterprises, Inc. (since 1998), Chairman of the Board, President, and Chief Executive Officer, Constellation Power Source, Inc. (since 1997)	Chairman of the Board and Chief Executive Officer--Constellation Energy Source, Inc., Vice President, Chief Financial Officer & Secretary--BGE
Robert E. Denton	58	President and Chief Executive Officer of Constellation	Executive Vice President, Generation--BGE, Senior

		Nuclear, LLC (since July 1, 2000)	Vice President, Generation--BGE
Frank O. Heintz	57	President and Chief Executive Officer of Baltimore Gas and Electric Company (since July 1, 2000)	Executive Vice President, Utility Operations--BGE, Vice President, Gas--BGE.
Thomas F. Brady	51	Vice President Corporate Strategy and Development (Since formation of Constellation Energy Group as the holding company on April 30, 1999; since January 1, 1999 for BGE)	Vice President, Retail Services--BGE, Vice President, Customer Service and Distribution--BGE
David A. Brune	60	Vice President Finance and Accounting, Chief Financial Officer and Secretary (Since formation of Constellation Energy Group as the holding company on April 30, 1999; since February 25, 1997 for BGE)	General Counsel--BGE

Name	Age	Present Office	Other Offices or Positions Held During Past Five Years
Robert S. Fleishman	47	Vice President Corporate Affairs and General Counsel (Since formation of Constellation Energy Group as the holding company on April 30, 1999; since May 1, 1998 for BGE)	General Counsel--BGE, Associate General Counsel--Regulatory at BGE
Janet E. McHugh	43	Vice President Human Resources (Since June 1, 2000)	Deputy General Counsel and Manager, Legal Department--Constellation Energy, Associate General Counsel--Commercial Unit--BGE

(A) Chief Executive Officer, Director, and member of the Executive Committee.
(B) Director and member of the Executive Committee, Long-Range Strategy Committee, and Risk Management Committee.

Officers of Constellation Energy Group 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, 2001, there were 58,650 common shareholders of record.

Dividend Policy

Constellation Energy pays dividends on its common stock after its Board of Directors declares them. There is no limitation on Constellation Energy paying common stock dividends.

BGE pays dividends on its common stock after its Board of Directors declares them. There is no limitation 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.

Dividends have been paid on the common stock continuously since 1910. Future dividends depend upon future earnings, our financial condition, and other factors. Effective April 2001, our annual dividend is expected to be set at $.48 per share ($.12 quarterly). Upon separation, BGE Corp. expects to pay initial annual dividends of $.48 per share, and Constellation Energy Group, as a growing merchant energy company, initially expects to reinvest its earnings in order to fund its growth plans and not to pay a dividend.

Quarterly dividends were declared on the common stock during 2000 and 1999 in the amounts set forth below. Dividends paid prior to April 30, 1999 were on BGE common stock. As a result of the share exchange, Constellation Energy is the successor of BGE.

Common Stock Dividends and Price Ranges

	2000			1999		
	Dividend Declared	Price* High	Price* Low	Dividend Declared	Price* High	Price* Low
First Quarter	$ .42	$33.81	$27.06	$ .42	$31.13	$24.69
Second Quarter	.42	35.69	31.25	.42	31.38	25.13
Third Quarter	.42	52.06	32.06	.42	30.88	27.19
Fourth Quarter	.42	50.50	37.88	.42	31.50	27.50
Total	$1.68			$1.68		

* Based on New York Stock Exchange Composite Transactions as reported in THE WALL STREET JOURNAL.

Item 6. SELECTED FINANCIAL DATA

Constellation Energy Group Inc., and Subsidiaries

	2000	1999	1998
	(Dollar amounts in millions, excep		
Summary of Operations			
Total Revenues	$ 3,878.5	$3,786.2	$3,386.4
Total Expenses	3,038.3	3,026.3	2,647.9
Income From Operations	840.2	759.9	738.5
Other Income (Expense)	6.6	7.9	5.7
Income Before Fixed Charges and Income Taxes	846.8	767.8	744.2
Fixed Charges	271.4	255.0	260.6
Income Before Income Taxes	575.4	512.8	483.6
Income Taxes	230.1	186.4	177.7
Income Before Extraordinary Item	345.3	326.4	305.9
Extraordinary Loss, Net of Income Taxes	--	(66.3)	--
Net Income	$ 345.3	$ 260.1	$ 305.9
Earnings Per Share of Common Stock and Earnings Per Share of Common Stock-- Assuming Dilution Before Extraordinary Item	$ 2.30	$ 2.18	$ 2.06
Extraordinary Loss, Net of Income Taxes	--	(.44)	--
Earnings Per Share of Common Stock and Earnings Per Share of Common Stock-- Assuming Dilution	$ 2.30	$ 1.74	$ 2.06
Dividends Declared Per Share of Common Stock	$ 1.68	$ 1.68	$ 1.67
Summary of Financial Condition			
Total Assets	$12,384.6	$9,683.8	$9,434.1
Capitalization			
Long-term debt	$ 3,159.3	$2,575.4	$3,128.1
Redeemable preference stock	--	--	--
Preference stock not subject to mandatory redemption	190.0	190.0	190.0
Common shareholders' equity	3,153.0	2,993.0	2,981.5
Total Capitalization	$ 6,502.3	$5,758.4	$6,299.6
Financial Statistics at Year End			
Ratio of Earnings to Fixed Charges	2.78	2.87	2.60
Book Value Per Share of Common Stock	$ 20.95	$ 20.01	$ 19.98
Number of Common Shareholders (In Thousands)	60.1	66.1	69.9

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

Baltimore Gas and Electric Company and Subsidiaries

	2000	1999	1998
	(Dollar amounts in millions, excep		
Summary of Operations			
Total Revenues	$ 2,746.8	$3,092.2	$3,386.4
Total Expenses	2,336.7	2,387.9	2,647.9
Income From Operations	410.1	704.3	738.5
Other Income (Expense)	9.8	8.4	5.7
Income Before Fixed Charges and Income Taxes	419.9	712.7	744.2
Fixed Charges	184.0	205.9	238.8
Income Before Income Taxes	235.9	506.8	505.4
Income Taxes	92.4	178.4	177.7
Income Before Extraordinary Item	143.5	328.4	327.7
Extraordinary Loss, Net of Income Taxes	--	(66.3)	--
Net Income	143.5	262.1	327.7
Preference Stock Dividends	13.2	13.5	21.8
Earnings Applicable to Common Stock	$ 130.3	$ 248.6	$ 305.9
Summary of Financial Condition			
Total Assets	$ 4,654.2	$7,272.6	$9,434.1
Capitalization			
Long-term debt	$ 1,864.4	$2,206.0	$3,128.1
Redeemable preference stock	--	--	--
Preference stock not subject to mandatory redemption	190.0	190.0	190.0
Common shareholders' equity	802.3	2,355.4	2,981.5
Total Capitalization	$ 2,856.7	$4,751.4	$6,299.6
Financial Statistics at Year End			
Ratio of Earnings to Fixed Charges	2.27	3.45	2.94
Ratio of Earnings to Combined Fixed Charges and Preferred and Preference Stock Dividends	2.03	3.14	2.60

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

Item 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

INTRODUCTION

On April 30, 1999, Constellation Energy(R) Group, Inc. (Constellation Energy) became the holding company for Baltimore Gas and Electric Company (BGE(R)) and Constellation(R) Enterprises, Inc. Constellation Enterprises was previously owned by BGE.

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. Reference in this report to the "utility business" is to BGE.

Constellation Energy's subsidiaries primarily include a domestic merchant energy business focused mostly on power marketing and merchant generation in North America, and BGE.

We realigned our organization in response to the deregulation of electric generation in Maryland. In the first quarter of 2000, we combined our wholesale power marketing operation with our domestic plant development and operation activities to form a domestic merchant energy business. At the same time, we revised our operating segments to reflect those realignments as presented in Note 2.

On July 1, 2000, as a result of the deregulation of electric generation, BGE transferred its generating assets and related liabilities at book value to new nonregulated subsidiaries -- Calvert Cliffs Nuclear Power Plant, Inc. and Constellation Power Source Generation, Inc. We discuss the deregulation of electric generation in the Current Issues--Electric Competition section.

Effective July 1, 2000, we formed a nonregulated holding company, Constellation Power Source Holdings, Inc., that oversees:

- the wholesale power marketing and risk management activities of Constellation Power Source,(TM) Inc.,
- the domestic power projects of Constellation Investments,(TM) Inc. and Constellation Power,(TM) Inc., and subsidiaries, and
- the generating assets of Constellation Power Source Generation, Inc.

As a result of these changes, our domestic merchant energy business includes the operations of Constellation Power Source Holdings, the nuclear generation of Calvert Cliffs Nuclear Power Plant, Inc., and the nuclear consulting services of Constellation Nuclear,(TM) LLC.

Also, effective July 1, 2000, the financial results of the electric generation portion of our business are included in the domestic merchant energy business. Prior to that date, the financial results of electric generation were included in BGE's regulated electric business.

BGE remains a regulated electric and gas public utility distribution company with a service territory in the City of Baltimore and all or part of ten counties in Central Maryland.

Our other nonregulated businesses include the:

- Latin American power projects of Constellation Power, and subsidiaries,
- energy products and services of Constellation Energy Source,(TM) Inc.,

- home products, commercial building systems, and residential and commercial electric and gas retail marketing of BGE Home Products & Services,(TM) Inc. and subsidiaries,
- general partnership, in which BGE is a partner, of District Chilled Water General Partnership (ComfortLink(R)) that provides cooling services for commercial customers in Baltimore,
- financial investments of Constellation Investments, and
- real estate holdings and senior-living facilities of Constellation Real Estate Group,(TM) Inc.

As discussed further in the Strategy section, on October 23, 2000, we announced initiatives to separate our domestic merchant energy business from our remaining businesses. These remaining businesses include BGE and the other nonregulated businesses described above.

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

- what factors affect our businesses,
- what our earnings and costs were in 2000 and 1999,
- why our earnings and costs changed from the year before,
- where our earnings come from,
- how all of this affects our overall financial condition,
- what our expenditures for capital projects were for 1998 through 2000, and what we expect them to be through 2003, and
- where we expect to get 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 2000, 1999, and 1998. We analyze and explain the differences between periods by operating segment. Our analysis is important in making decisions about your investments in Constellation Energy and/or BGE.

Also, this discussion and analysis is based on the operation of the electric generation portion of our utility business under rate regulation through June 30, 2000. Our regulated electric business changed as we transferred our electric generation assets and related liabilities to our domestic merchant energy business and we entered into retail customer choice for electric generation effective July 1, 2000. In addition, we announced our intention to separate our domestic merchant energy business from our remaining businesses. Accordingly, the results of operations and financial condition described in this discussion and analysis are not necessarily indicative of future performance.

STRATEGY

Customer choice and regulatory change significantly impact our business. In response to these, we regularly evaluate our strategies with two goals in mind: to improve our competitive position, and to anticipate and adapt to regulatory change. Prior to July 1, 2000, the majority of our earnings were from BGE. Going forward, prior to separating into two companies, we expect to derive almost two-thirds of our earnings from our domestic merchant energy business.

While BGE continues to be regulated and to deliver electricity and natural gas through its core distribution business, our primary growth strategies center on the nonregulated domestic merchant energy business with the objective of providing new sources of earnings growth.

On October 23, 2000, we announced three initiatives to advance our growth strategies. The first initiative is that we entered into an agreement (the "Agreement") with an affiliate of The Goldman Sachs Group, Inc. ("Goldman Sachs"). Under the terms of the Agreement, Goldman Sachs will acquire up to a 17.5% equity interest in our domestic merchant energy business, which will be consolidated under a single holding company ("Holdco"). Goldman Sachs will also acquire a ten-year warrant for up to 13% of Holdco's common stock (subject to certain adjustments). The warrant is exercisable six months after Holdco's common stock becomes publicly available. The amount of common stock which Goldman Sachs may receive upon exercise will be equal to the excess of the market price of Holdco's common stock at the time of exercise over the exercise price of $60 per share for all the stock subject to the warrant, divided by the market price. Holdco may at its option pay Goldman Sachs such excess in cash. Goldman Sachs is acquiring its interest and the warrant in exchange for $250 million in cash (subject to adjustment in certain instances) and certain assets related to our power marketing operation. At closing, Goldman Sachs' existing services agreement with our power marketing operation will terminate.

The second initiative is a plan to separate our domestic merchant energy business from our remaining businesses as discussed in the introduction. The separation will create two stand-alone, publicly traded energy companies. One will be a merchant energy business engaged in wholesale power marketing and generation under the name "Constellation Energy Group" after the separation. The other will be a regional retail energy delivery and energy services company, BGE Corp., which will include BGE, our other nonregulated businesses, and our investment in Orion Power Holdings, Inc. ("Orion").

As a result of the separation, shareholders will continue to own all of Constellation Energy's current businesses through their ownership of the stock of the new Constellation Energy Group and of BGE Corp.

The third initiative is a change in our common stock dividend policy effective April 2001. In a move closely aligned with our separation plan, effective April 2001, our annual dividend is expected to be set at $.48 per share. After the separation, BGE Corp. expects to pay initial annual dividends of $.48 per share. Constellation Energy Group, as a growing merchant energy company, initially expects to reinvest its earnings in order to fund its growth plans and not to pay a dividend.

The closing of the transaction with Goldman Sachs and the separation are subject to customary closing conditions and contingent upon obtaining regulatory approvals and a Private Letter Ruling from the Internal Revenue Service regarding certain tax matters. The transaction and separation are expected to be completed by mid to late 2001. At the date of this report, we received approval from the Federal Energy Regulatory Commission (FERC).

We discuss these strategic initiatives further in our Report on Form 8-K and exhibits filed with the Securities and Exchange Commission (SEC)on October 23, 2000.

Currently, our domestic merchant energy business controls over 9,000 megawatts of generation. In December 2000, we announced that a subsidiary of Constellation Nuclear will purchase 1,550 megawatts of the 1,757 megawatts total generating capacity of the Nine Mile Point nuclear power plant located in Scriba, New York. The total purchase price, including fuel, is $815 million. We discuss the planned acquisition of the Nine Mile Point power plant in more detail in Note 10.

We also are constructing generating facilities representing 1,100 megawatts of natural gas-fired peaking capacity in the Mid-Atlantic and Mid-West regions which are expected to be operational by the summer of 2001. An additional 6,700 megawatts of natural gas-fired peaking and combined cycle production facilities in various regions of North America are scheduled for completion in 2002 and beyond. By 2005, our domestic merchant energy business expects to control approximately 30,000 megawatts through the construction or purchase of additional nuclear and non-nuclear generation assets and through contractual arrangements.

We decided to exit the Latin American portion of our operation as a result of our concentration on domestic merchant energy. Currently, we are actively seeking a buyer for the Latin American portion of our business and are working toward completing our exit strategy in 2001.

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

. the complete or partial separation of our transmission and distribution functions,
. mergers or acquisitions of utility or non-utility businesses, and
. sale of generation assets or one or more businesses.

CURRENT ISSUES

With the shift toward customer choice, competition, and the growth of our domestic merchant energy business, various factors will affect our financial results in the future. These factors include, but are not limited to, operating our generation assets in a deregulated market without the benefit of a fuel rate adjustment clause, the timing and implications of deregulation in other regions where our domestic merchant energy business will operate, the loss of revenues due to customers choosing alternative suppliers, higher volatility of earnings and cash flows, and increased financial requirements of our domestic merchant energy business. Please refer to the Forward Looking Statements section for additional factors.

In this section, we discuss in more detail several issues that affect our businesses.

Electric Competition

We are facing electric competition on various fronts, including:

. the construction of generating units to meet increased demand for electricity,
. the sale of electricity in wholesale power markets,
. competing with alternative energy suppliers, and
. electric sales to retail customers.

Maryland

On April 8, 1999, Maryland enacted the Electric Customer Choice and Competition Act of 1999 (the "Act") and accompanying tax legislation that significantly restructured Maryland's electric utility industry and modified the industry's tax structure.

In the Restructuring Order discussed below, the Maryland Public Service Commission (Maryland PSC) addressed the major provisions of the Act. The accompanying tax legislation is discussed in detail in Note 4.

On November 10, 1999, the Maryland PSC issued a Restructuring Order that resolved the major issues surrounding electric restructuring, accelerated the timetable for customer choice, and addressed the major provisions of the Act.

The Restructuring Order also resolved the electric restructuring proceeding (transition costs, customer price protections, and unbundled rates for electric services) and a petition filed in September 1998 by the Office of People's Counsel (OPC) to lower our electric base rates. The major provisions of the Restructuring Order are discussed in Note 4.

We believe that the Restructuring Order provided sufficient details of the transition plan to competition for BGE's electric generation business to require BGE to discontinue the application of Statement of Financial Accounting Standards (SFAS) No. 71, Accounting for the Effects of Certain Types of Regulation for that portion of its business. Accordingly, in the fourth quarter of 1999, we adopted the provisions of SFAS No. 101, Regulated Enterprises--Accounting for the Discontinuation of FASB Statement No. 71 and Emerging Issues Task Force Consensus (EITF) No. 97-4, Deregulation of the Pricing of Electricity--Issues Related to the Application of FASB Statements No. 71 and 101 for BGE's electric generation business. BGE's transmission and distribution business continues to meet the requirements of SFAS No. 71 as that business remains regulated. We describe the effect of applying these accounting requirements in Note 4.

Please refer to Note 10 for a discussion regarding appeals of the Restructuring Order.

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

- All customers, except a few commercial and industrial companies that have signed contracts with BGE, can choose their electric energy supplier. BGE will provide a standard offer service for customers that do not select an alternative supplier. In either case, BGE will continue to deliver electricity to all customers in areas traditionally served by BGE.
- BGE reduced residential base rates by approximately 6.5%, on average about $54 million a year. These rates will not change before July 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. In total, these generating assets represent about 6,240 megawatts of generation capacity with a total net book value at June 30, 2000 of approximately $2.4 billion.
- 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. Also, Constellation Power Source Generation issued approximately $366 million in unsecured promissory notes to BGE. Repayments of the notes by Constellation Power Source Generation will be used exclusively to service the current maturities of certain BGE long-term debt.
- BGE transferred equity associated with the generating assets to Calvert Cliffs Nuclear Power Plant, Inc. and Constellation Power Source Generation.
- The fossil fuel and nuclear fuel inventories, materials and supplies, and certain purchased power contracts of BGE were also assumed by these subsidiaries.

Effective July 1, 2000, BGE provides standard offer service to customers at fixed rates over various time periods during the transition period for those customers that do not choose an alternate supplier. In addition, the electric fuel rate was discontinued effective July 1, 2000. Constellation Power Source provides BGE with the energy and capacity required to meet its standard offer service obligations for the first three years of the transition period. Thereafter, BGE will competitively bid the energy and capacity.

Constellation Power Source obtains the energy and capacity to supply BGE's standard offer service obligations from affiliates that own Calvert Cliffs Nuclear Power Plant (Calvert Cliffs) and BGE's former fossil plants, supplemented with energy and capacity purchased from the wholesale market as necessary.

Other States

Our domestic merchant energy business is focused on expanding its business through marketing energy products to wholesale customers and acquiring control of additional generating facilities. This business will focus on states with strong growth in energy demand and that provide opportunities through ongoing deregulation and the creation of competitive markets. Delays in, or the ultimate form of, deregulation of electric generation in various states may affect our domestic merchant energy business strategy.

Our domestic merchant energy business has $297.9 million invested in power projects that sell 142 megawatts of electricity in California under power purchase agreements as discussed in the California Power Purchase Agreements section. The counterparties to the agreements are two California investor-owned utilities. Due to various factors, including shortage of generation and the high cost of natural gas, these utilities' financial condition was severely impacted because they were paying more for power than they were allowed to recover from their customers under the deregulation plan in California. As a result, these utilities have not been able to maintain current payments for the power they purchased to meet their customers' energy needs and the credit ratings of these utilities were downgraded below investment grade. The governor and legislature of California have undertaken emergency actions to stabilize the financial condition of the two utilities by purchasing power on behalf of these utilities and pursuing legislation that should permit the utilities to pay their power costs.

In the meantime, these utilities have not been paying our California projects in full for power supplied to them from December 2000. As of the date of this report, our portion of the amount due from these utilities is approximately $42 million. While we expect to be paid for this power, we cannot predict when payment will occur or if full payment will be received. We have taken reserves in amounts we believe to be reasonable under the circumstances. On March 27, 2001, the California Public Utilities Commission issued an order for an immediate retail rate increase. Accordingly, we expect that this order should enable these utilities to pay us for all future power supplied to these utilities. However, if the ultimate resolution of the events in California prevents collection of unpaid balances under power purchase agreements by some or all of our projects, it could have a material impact on our financial results. Additionally, if the events in California result in a modification or termination of these agreements that reduces future cash flows, we would have to evaluate whether our investments in the power projects that are parties to the agreements are impaired. An impairment of these investments could have a material impact on our financial results. Our domestic merchant energy business does not have any other direct agreements with these utilities. However, we may be impacted if one or more of our other counterparties is significantly affected by the events in California, or by the operation of the California Power Exchange.

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.

Under traditional rate regulation that continues after July 1, 2000 for BGE's electric transmission and distribution, and gas businesses, the Maryland PSC determines the rates we can charge our customers. Prior to July 1, 2000, BGE's regulated electric rates consisted primarily of a "base rate" and a "fuel rate." Effective July 1, 2000, BGE discontinued its electric fuel rate and unbundled its 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 fixed asset 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 November 17, 1999, BGE filed an application with the Maryland PSC to increase its gas 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 Restructuring Order, BGE's residential electric base rates are frozen until 2006.

Electric delivery service rates are frozen for a four-year period 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 went up, the Maryland PSC permitted us to increase the fuel rate.

Under the Restructuring Order, 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 are collecting this accumulated difference from customers over the twelve-month period beginning October 2000. Effective July 1, 2000, our 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 in more detail in the Gas Cost Adjustments section and in Note 1.

FERC Regulation--Regional Transmission Organizations

In December 1999, FERC issued Order 2000, amending its regulations under the Federal Power Act to advance the formation of Regional Transmission Organizations (RTOs). The regulations require that each public utility that owns, operates, or controls facilities for the transmission of electric energy in interstate commerce make certain filings with respect to forming and participating in a RTO. FERC also identified the minimum characteristics and functions that a transmission entity must satisfy in order to be considered a RTO.

According to Order 2000, a public utility that is a member of an existing transmission entity that has been approved by FERC as in conformance with the Independent System Operator (ISO) principles set forth in the FERC Order No. 888, such as BGE, through its membership in PJM (Pennsylvania-New Jersey-Maryland) Interconnection, was required to make a filing no later than January 15, 2001. PJM and the joint transmission owners, including BGE, made the filing on October 11, 2000. That filing explained the extent to which PJM met the minimum characteristics and functions of a RTO and explained its plans to conform to these characteristics and functions.

As a member of PJM, an existing ISO, BGE does not expect to be materially impacted by Order 2000. However, we are appealing two requirements of Order 2000 whereby:

- we would have to go through PJM to make a filing with FERC to change our transmission rates, and
- we would have to transfer operational control of our transmission facilities to PJM.

The U.S. Supreme Court agreed to hear an appeal by others of FERC Order 888. We cannot predict the outcome of this appeal or the impact on BGE at this time.

Weather

Domestic Merchant Energy Business

Weather conditions in the different regions of North America influence the financial results of our domestic merchant energy business. Typically, demand for electricity and its price are higher in the summer and the winter, when weather is more extreme. However, all regions of North America typically do not experience extreme weather conditions at the same time. Since the majority of our generating plants currently are located in PJM, our financial results are affected, to a greater extent, by weather conditions in this area. However, by 2005, we expect to control approximately 30,000 megawatts of generation throughout various regions of North America.

Current weather conditions also can affect the forward market price of energy commodity and derivative contracts used by our power marketing operation that are accounted for on a mark-to-market basis. To the extent that our power marketing operation purchases and sells such contracts, our financial results could be influenced by the impact that weather conditions have on the market price of such contracts.

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." A degree 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 2000 and 1999, 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.

	2000	1999	30-year Average
Cooling degree days	736	845	840
Percentage change from prior year	(12.9)%	(7.7)%	
Heating degree days	4,936	4,585	4,771
Percentage change from prior year	7.7%	11.3%	

Other Factors

Other factors, aside from weather, 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. Under the Restructuring Order, BGE's electric customers can become delivery service customers only and can purchase their electricity from other sources. We will collect a delivery service charge to recover the fixed costs for the service we provide. The remaining electric customers will receive standard offer service from BGE at the fixed rates provided by the Restructuring Order. 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 and legal matters in Note 10. You will find additional details of our environmental matters under Item 1. Business -- Environmental Matters. Some of the information is about costs that may be material to our financial results.

Accounting Standards Issued

We discuss recently 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 earnings for our operating segments. Changes in fixed charges and income taxes are discussed in the aggregate for all segments in the Consolidated Nonoperating Income and Expenses section.

Overview

Total Earnings Per Share of Common Stock

	2000*	1999	1998
Earnings before nonrecurring charges included in operations:			
Domestic merchant energy	$1.48	$ .44	$ .36
Regulated electric	.71	1.81	1.75
Regulated gas	.20	.22	.18
Other nonregulated	.04	.01	(.09)
Total earnings per share before nonrecurring charges included in operations:	2.43	2.48	2.20
Nonrecurring charges included in operations (see Note 2):			
Deregulation transition cost	(.10)	--	--
TVSERP	(.03)	--	--
Hurricane Floyd	--	(.03)	--
Write-downs of power projects	--	(.12)	--
Write-off of energy services investment	--	--	(.04)
Write-down of financial investment	--	(.11)	--
Write-down of real estate and senior-living			

investments	--	(.04)	(.10)
Total earnings per share before extraordinary item	2.30	2.18	2.06
Extraordinary loss (see Note 4)	--	(.44)	--
Total earnings per share	$2.30	$1.74	$2.06

*Earnings for the years presented reflect a significant shift from the regulated electric business to the domestic merchant energy business as a result of the transfer of BGE's electric generation assets to nonregulated subsidiaries on July 1, 2000 in accordance with the Restructuring Order. We discuss the Restructuring Order in more detail in Note 4.

2000

Our 2000 total earnings increased $85.2 million, or $.56 per share, compared to 1999 mostly because we recorded an extraordinary charge of $66.3 million, or $.44 per share, associated with the deregulation of the electric generation portion of our business in 1999. In addition, we recorded several nonrecurring charges in 1999 that had a negative impact in that year as discussed below. In 2000, we recorded the following nonrecurring charges in operations:

- $15.0 million after-tax, or $.10 per share, deregulation transition cost in June 2000 to a third party incurred by our power marketing operation to provide BGE's standard offer service requirements, and
- $4.2 million after-tax, or $.03 per share, expense during the first and second quarters of 2000 for BGE employees that elected to participate in a Targeted Voluntary Special Early Retirement Program (TVSERP).

Earnings before nonrecurring charges included in operations decreased $7.3 million, or $.05 per share, mostly because we recognized $29.9 million, or $18.1 million after-tax, of the 6.5% annual residential rate reduction that was effective July 1, 2000 and we had higher interest costs in 2000 compared to 1999. We also recognized $5.7 million after-tax, or $.04 per share, for contributions to the universal service fund relating to the deregulation of electric generation. These decreases were offset partially by higher earnings in our domestic merchant energy and our other nonregulated businesses.

In 2000, earnings from our domestic merchant energy business before nonrecurring charges increased compared to 1999 because of higher earnings in both our power marketing and domestic generation operations.

In 2000, earnings from our other nonregulated businesses increased mostly because of higher earnings in our financial investments operation.

1999

Our 1999 total earnings decreased $45.8 million, or $.32 per share, compared to 1998. Our total earnings decreased mostly because we recorded an extraordinary charge associated with the deregulation of the electric generation portion of our business. We discuss the extraordinary charge in Note 4. Our 1999 total earnings also include the following nonrecurring items included in our operations:

- Our regulated electric business recorded $4.9 million after-tax, or $.03 per share, of expenses related to Hurricane Floyd.

. Our domestic generation operation recorded write-downs of certain power projects for $14.2 million after-tax, or $.09 per share, and our Latin American operation recorded a $4.5 million after-tax, or $.03 per share, write-down of a power project.
. Our financial investments operation recorded a $16.0 million after-tax, or $.11 per share, write-down of a financial investment.
. Our real estate and senior-living facilities operation recorded a $5.8 million after-tax, or $.04 per share, write-down of certain senior-living facilities.

These decreases were offset partially by higher earnings from regulated utility, domestic merchant energy, and other nonregulated business operations excluding nonrecurring charges.

In 1999, regulated utility earnings before the extraordinary charge increased compared to 1998 mostly because we had higher electricity and gas system sales that year, and we settled a capacity contract with PECO Energy Company in 1998 that had a negative impact on earnings in that year. This increase was offset partially by higher depreciation and amortization expense mostly due to the $75.0 million amortization of the regulatory asset recorded in 1999 for the reduction of our generation plant under the Restructuring Order, which reduced 1999 earnings by $48.8 million.

In 1999, earnings from our domestic merchant energy business before nonrecurring charges increased compared to 1998 mostly because of higher earnings from our power marketing operation.

In 1999, earnings from our other nonregulated businesses before nonrecurring charges increased compared to 1998 mostly because of higher earnings from our Latin American and real estate and senior-living facilities operations.

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

Domestic Merchant Energy Business

Our domestic merchant energy business engages primarily in power marketing and domestic power generation. As discussed in the Current Issues--Electric Competition section, our domestic merchant energy business was significantly impacted by the July 1, 2000 implementation of customer choice in Maryland. At that time, BGE's generating assets became part of our nonregulated domestic merchant energy business, and Constellation Power Source began selling to BGE the energy and capacity required to meet its standard offer service obligations for the first three years of the transition period.

Constellation Power Source 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. Constellation Power Source also manages our wholesale market price risk.

In addition, effective July 1, 2000, domestic merchant energy business revenues include 90% of the competitive transition charges BGE collects from its customers (CTC revenues) and the portion of BGE's revenues providing for nuclear decommissioning costs.

Our earnings are exposed to various market risks as discussed in the Market Risk section. For example, our earnings are exposed to the risks of the competitive wholesale electricity market to the extent that our domestic merchant energy business has to purchase energy and/or capacity to meet obligations to supply power or meet other energy-related contractual arrangements at prices which may approach or exceed the applicable fixed sales price obligations. If the price of obtaining energy in the wholesale market exceeds the fixed sales price, our earnings would be adversely affected. We also are affected by operational risk, that is, the risk that a generating plant will not be available to produce energy when the energy is required. Imbalances in demand and supply can occur not only because of plant outages, but also because of transmission constraints, or extreme temperatures (hot or cold) causing demand to exceed available supply.

We cannot estimate the impact of the increased financial risks associated with the competitive wholesale electricity market. However, these financial risks could have a material impact on our financial results.

Earnings

	2000	1999	1998
	(In millions, except per share amounts)		
Revenues	$992.0	$212.9	$147.3
Operating expenses	534.3	111.1	47.8
Depreciation and amortization	80.9	5.0	3.0
Taxes other than income taxes	24.1	--	--
Income from operations	$352.7	$ 96.8	$ 96.5
Net income	$206.8	$ 52.4	$ 53.1
Total earnings per share before nonrecurring charges included in operations:	$ 1.48	$ .44	$ .36
Deregulation transition cost	(.10)	--	--
Write-down of power projects	--	(.09)	--
Earnings per share	$ 1.38	$ .35	$ .36

Above amounts include intercompany transactions eliminated in our Consolidated Financial Statements. Note 2 provides a reconciliation of operating results by segment to our Consolidated Financial Statements.

Revenues

Our 2000 domestic merchant energy revenues increased $779.1 million compared to 1999 mostly because of:

- a $581.0 million increase related to providing BGE the energy and capacity required to meet its standard offer service obligation effective July 1, 2000,
- a $110.0 million increase related to CTC and decommissioning revenues included in the domestic merchant energy business effective July 1, 2000, and
- higher revenues from our power marketing and domestic generation operations.

Our 1999 domestic merchant energy revenues increased $65.6 million compared to 1998 mostly because of higher revenues from our power marketing operation offset partially by lower revenues from our domestic generation operation.

We discuss the revenues for our power marketing and domestic generation operations in the sections below.

Power Marketing

Power marketing revenues increased during 2000 compared to 1999 mostly because of higher transaction volumes in the Mid-Atlantic, Texas, and West regions, offset partially by lower margins.

Power marketing revenues increased during 1999 compared to 1998 mostly because of higher transaction margins and volumes.

Constellation Power Source uses the mark-to-market method of accounting. We discuss the mark-to-market method of accounting and Constellation Power Source's activities in more detail in Note 1. As a result of the nature of its operations and the use of mark-to-market accounting, Constellation Power Source's revenues and earnings will fluctuate. We cannot predict these fluctuations, but the effect on our revenues and earnings could be material. The primary factors that cause these fluctuations are:

- the number and size of new transactions,
- the magnitude and volatility of changes in commodity prices and interest rates, and
- the number and size of open commodity and derivative positions Constellation Power Source holds or sells.

Constellation Power Source's management uses its best estimates to determine the fair value of commodity and derivative positions 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, it is possible that future market prices could vary from those used in recording assets and liabilities from power marketing and trading activities, and such variations could be material. Assets and liabilities from energy trading activities (as shown in our Consolidated Balance Sheets) increased significantly at December 31, 2000 compared to December 31, 1999 because of business growth during the period and increased market prices at the end of 2000.

Domestic Generation

Our domestic generation revenues increased during 2000 compared to 1999 mostly because of three factors:

- Our domestic generation operation recognized $13.3 million on the termination of an operating arrangement and the sale of certain subsidiaries. In April 2000, Constellation Operating Services, Inc. (COSI), a subsidiary of Constellation Power, Inc., ended its exclusive arrangement with Orion to operate Orion's facilities. Orion purchased from COSI the four subsidiary companies formed to operate power plants owned by Orion.
- In November 2000, our domestic generation operation recorded a $19.2 million gain on the sale of approximately 3.2 million shares of Orion stock.
- In 1999, our domestic generation operation recorded a write-off of two geothermal power projects as discussed below, which had a negative impact in that year.

In 1999, our domestic generation revenues decreased compared to 1998 mostly because of three factors:

- Our domestic generation operation wrote-off two geothermal power projects that totaled $21.4 million. These write-offs occurred because the expected future cash flows from the projects were less than the investment in the projects. For the first project, this resulted from the inability to restructure certain project agreements. For the second project, the water temperature of the geothermal resource used by one of the plants for production declined.

- In 1998, our domestic generation operation recorded a $17.2 million gain for its share of earnings in a partnership. The partnership recognized a gain on the sale of its ownership interest in a power purchase agreement.
- Revenues from our California power purchase agreements decreased as discussed below.

California Power Purchase Agreements

Our domestic generation operation has $297.9 million invested in 14 projects that sell electricity in California under power purchase agreements called "Interim Standard Offer No. 4" agreements.

Under these agreements, the electricity rates changed from fixed rates to variable rates beginning in 1996. In 2000, the last four projects transitioned to variable rates. In 1999 and prior years, the projects that transitioned to variable rates had lower revenues under variable rates than they did under fixed rates. In 2000, the prices received under these agreements were higher due to increases in the variable-rate pricing terms. However, due to the uncertainties in California, the recent increases in prices may not be indicative of future prices. We discuss the developments in California in the Current Issues--Electric Competition section.

We also describe these projects and the transition process in Note 3 and Note 10.

Operating Expenses

During 2000, domestic merchant energy operating expenses increased $423.2 million compared to 1999 mostly because of three factors:

- An increase of $191.6 million in fuel costs and $157.2 million in operations and maintenance costs. These costs were associated with the generation plants that were transferred from BGE effective July 1, 2000.
- A $24.0 million deregulation transition cost in June 2000 to a third party incurred by our power marketing operation to provide BGE's standard offer service requirements.
- An increase in power marketing operating expenses due to the growth of the operation.

During 1999, domestic merchant energy operating expenses increased $63.3 million compared to 1998 mostly because of the growth in our power marketing operation.

Depreciation and Amortization Expense

In 2000, domestic merchant energy depreciation and amortization expense increased $75.9 million compared to 1999 mostly because of $73.8 million of expenses associated with the generation plants that were transferred from BGE effective July 1, 2000.

In 1999, domestic merchant energy depreciation and amortization expense was about the same compared to 1998.

Taxes Other than Income Taxes

In 2000, domestic merchant energy taxes other than income taxes increased $24.1 million compared to 1999 because of $23.8 million of taxes other than income taxes associated with the generation plants that were transferred from BGE effective July 1, 2000.

In 1999, domestic merchant energy taxes other than income taxes were the same compared to 1998.

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 domestic merchant energy business on that date.

Earnings

	2000	1999	1998
	(In millions, except per share amounts)		
Electric revenues	$2,135.2	$2,260.0	$2,220.8
Electric fuel and purchased energy	870.7	487.7	516.7
Operations and maintenance	454.2	629.6	630.5
Depreciation and amortization	319.9	376.4	313.0
Taxes other than income taxes	157.8	188.9	182.3
Income from operations	$ 332.6	$ 577.4	$ 578.3
Net income	$ 102.3	$ 198.8	$ 259.6
Total earnings per share before nonrecurring charges included in operations:	$ .71	$ 1.81	$ 1.75
TVSERP	(.03)	--	--
Hurricane Floyd	--	(.03)	--
Extraordinary loss	--	(.44)	--
Earnings per share	$ .68	$ 1.34	$ 1.75

Above amounts include intercompany transactions eliminated in our Consolidated Financial Statements. Note 2 provides a reconciliation of operating results by segment to our Consolidated Financial Statements.

Electric Revenues

The changes in electric revenues in 2000 and 1999 compared to the respective prior year were caused by:

	2000	1999
	(In millions)	
Electric system sales volumes	$ 40.9	$41.3
Rates	(119.9)	4.5
Fuel rate surcharge	12.6	--
Total change in electric revenues from electric system sales	(66.4)	45.8

Interchange and other sales	(58.3)	(8.7)
Other	(0.1)	2.1
Total change in electric revenues	$(124.8)	$39.2

Electric System Sales Volumes

"Electric system sales volumes" are sales to customers in our service territory at rates set by the Maryland PSC. These sales do not include interchange sales and sales to others.

The percentage changes in our electric system sales volumes, by type of customer, in 2000 and 1999 compared to the respective prior year were:

	2000	1999
Residential	2.9%	3.5%
Commercial	3.5	2.6
Industrial	2.9	(5.1)

In 2000, we sold more electricity to residential customers compared to 1999 due to the colder winter weather, higher usage per customer, and an increased number of customers, offset partially by mild summer weather. We sold more electricity to commercial customers mostly due to higher usage per customer and an increased number of customers. We sold more electricity to industrial customers due to higher usage by Bethlehem Steel and an increased number of customers, offset partially by lower usage by other industrial customers. Usage was higher at Bethlehem Steel as a result of a 1999 shut down for a planned upgrade to their facilities that temporarily reduced their electricity consumption.

In 1999, we sold more electricity to residential customers due to higher usage per customer, colder winter weather, and an increased number of customers compared to 1998. This increase was offset partially by milder spring and early summer weather. We sold more electricity to commercial customers mostly due to higher usage per customer, an increased number of customers, and colder winter weather. We sold less electricity to industrial customers mostly because usage by Bethlehem Steel and other industrial customers decreased. This decrease was offset partially by an increase in the number of industrial customers.

Rates

Prior to July 1, 2000, our rates primarily consisted of an electric base rate and an electric fuel rate. Effective July 1, 2000, BGE discontinued its electric fuel rate and unbundled its rates to show separate components for delivery service, competitive transition charges, standard offer service (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 domestic merchant energy business effective July 1, 2000.

In 2000, rate revenues decreased compared to 1999 mostly because of the $29.9 million decrease caused by the 6.5% annual residential rate reduction, and the $110.0 million transfer of revenues to the domestic merchant energy business discussed above. This was offset partially by higher fuel rate revenues during the first half of 2000.

In 1999, rate revenues increased compared to 1998 because of higher fuel rate revenues. Fuel rate revenues increased mostly because we sold more electricity.

Fuel Rate Surcharge

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 discuss this further in the Electric Fuel Rate Clause section below.

Interchange and Other Sales

"Interchange and other sales" are sales in the PJM energy market and to others. PJM is an ISO that 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. These activities are now included in our domestic merchant energy business which resulted in a decrease in interchange and other sales for the second half of 2000 compared to 1999. In addition, BGE had lower interchange and other sales during the first half of 2000 when increased demand for system sales reduced the amount of energy BGE had available for off-system sales.

In 1999, interchange and other sales revenues decreased compared to 1998 mostly because higher demand for system sales reduced the amount of energy BGE had available for off-system sales.

Electric Fuel and Purchased Energy Expenses

	2000	1999	1998
	(In millions)		
Actual costs	$868.0	$558.0	$525.7
Net recovery (deferral) of costs under electric fuel rate clause	2.7	(70.3)	(9.0)
Total electric fuel and purchased energy expense	$870.7	$487.7	$516.7

Actual Costs

In 2000, our actual costs of fuel and purchased energy were higher compared to 1999 mostly because of the deregulation of our electric generation. As discussed in the Current Issues--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 domestic merchant energy business. In 2000, the cost of energy BGE purchased from our domestic merchant energy business was $581.0 million. The higher amount paid for purchased energy is offset by the absence of $191.6 million 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.

In 1999, our actual costs of fuel to generate electricity and electricity we bought from others were higher compared to 1998 mostly because the price of electricity we bought from others was higher. The price of electricity changes based on market conditions and contract terms. This increase was offset partially by our settlement of a capacity contract with PECO in 1998.

Electric Fuel Rate Clause

Prior to July 1, 2000, we deferred (included as an asset or liability on the Consolidated Balance Sheets and excluded from the 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 under the terms of the Restructuring Order. 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 are collecting this accumulated difference from customers over the twelve-month period beginning October 2000.

In 2000, the net deferral of costs under the electric fuel rate clause decreased compared to 1999 due to the discontinuation of the fuel rate clause effective July 1, 2000.

In 1999, the net deferral of costs under the electric fuel rate clause increased compared to 1998 because the 1999 deferral reflected higher purchased power costs, especially during record-setting summer peak loads.

Electric Operations and Maintenance Expenses

In 2000, regulated electric operations and maintenance expenses decreased $175.4 million compared to 1999 mostly because effective July 1, 2000, $157.2 million of costs were no longer incurred by this business segment. These costs were associated with the electric generation assets that were transferred to the domestic merchant energy business. In addition, 1999 operations and maintenance expenses included costs for system restoration activities related to Hurricane Floyd and a major winter ice storm, and costs associated with the preparation for the year 2000 (Y2K). These costs had a negative impact in that year. These decreases are offset partially by the $7.0 million of expense recognized in 2000 for electric business employees that elected to participate in the TVSERP.

In 1999, regulated electric operations and maintenance expenses were about the same compared to 1998. In 1999, operations and maintenance expenses included the costs for system restoration activities related to Hurricane Floyd and a major winter ice storm. This was offset by lower employee benefit costs in 1999 and a 1998 $6.0 million write-off of contributions to a third party for a low-level radiation waste facility that was never completed.

Electric Depreciation and Amortization Expense

In 2000, regulated electric depreciation and amortization expense decreased $56.5 million compared to 1999 mostly because of the absence of $73.8 million of depreciation and amortization expense associated with the transfer of the generation assets. This decrease was offset partially by more electric plant in service (as our level of plant in service changes, the amount of depreciation and amortization expense changes) and higher amortization associated with regulatory assets.

In 1999, regulated electric depreciation and amortization expense increased $63.4 million compared to 1998 mostly because of the $75.0 million amortization of the regulatory asset for the reduction in generation plant provided for in the Restructuring Order. This increase was offset partially by lower amortization of deferred electric conservation expenditures due to the write-off of a portion of these expenditures that will not be recovered under the Restructuring Order. We discuss the accounting implications of the Restructuring Order further in Note 4.

Electric Taxes Other Than Income Taxes

In 2000, regulated electric taxes other than income taxes decreased $31.1 million compared to 1999. This was mostly due to two factors:

- regulated electric taxes other than income taxes reflect the absence of $23.8 million of taxes other than income taxes associated with the generation assets that were transferred to the domestic merchant energy business effective July 1, 2000, and
- comprehensive changes to the tax laws.

The comprehensive tax law changes are discussed further in Note 4.

In 1999, regulated electric taxes other than income taxes increased slightly due to higher property and franchise taxes associated with increased electric revenues.

Regulated Gas Business

Earnings

	2000	1999	1998
(In millions, except per share amounts)			
Gas revenues	$611.6	$488.1	$451.1
Gas purchased for resale	350.6	233.8	209.4
Operations and maintenance	100.6	97.7	97.7
Depreciation and amortization	46.2	44.9	45.4
Taxes other than income taxes	34.8	34.5	32.5
Income from operations	$ 79.4	$ 77.2	$ 66.1
Net income	$ 30.6	$ 33.0	$ 26.1
Earnings per share	$ .20	$ .22	$ .18

Above amounts include intercompany transactions eliminated in our Consolidated Financial Statements. Note 2 provides a reconciliation of operating results by segment to our Consolidated Financial Statements.

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

Gas Revenues

The changes in gas revenues in 2000 and 1999 compared to the respective prior year were caused by:

	2000	1999
	(In millions)	
Gas system sales volumes	$ 34.5	$ 8.0
Base rates	2.7	2.2
Weather normalization	(26.7)	4.5
Gas cost adjustments	54.7	19.8
Total change in gas revenues from gas system sales	65.2	34.5
Off-system sales	58.1	2.0
Other	0.2	0.5
Total change in gas revenues	$123.5	$37.0

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Gas System Sales Volumes

The percentage changes in our gas system sales volumes, by type of customer, in 2000 and 1999 compared to the respective prior year were:

	2000	1999
Residential	13.0%	9.2%
Commercial	12.8	12.7
Industrial	(2.1)	(4.8)

In 2000, we sold more gas to residential and commercial customers compared to 1999 due to higher usage per customer, colder weather, and an increased number of customers. We sold less gas to industrial customers mostly because of lower usage by Bethlehem Steel and other industrial customers, offset partially by an increased number of customers.

In 1999, we sold more gas to residential customers mostly for two reasons: colder winter weather and an increased number of customers. This was offset partially by lower usage per customer. We sold more gas to commercial customers mostly because of higher usage per customer, colder winter weather, and an increased number of customers. We sold less gas to industrial customers mostly because of lower usage by Bethlehem Steel and other industrial customers.

Base Rates

In 2000, base rate revenues increased slightly compared to 1999 mostly because the Maryland PSC authorized a $6.4 million annual increase in our base rates effective June 22, 2000.

In 1999, base rate revenues increased compared to 1998 mostly because of the $16.0 million annual increase in our base rates approved by the Maryland PSC effective March 1, 1998.

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, and does not significantly impact earnings.

Delivery service customers, including Bethlehem Steel, 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 sales and are included in gas system sales volumes.

In 2000 and 1999, gas cost adjustment revenues increased compared to the respective prior year mostly because we sold more gas at a higher price. In 2000, the revenue increase reflects the significant increase in natural gas prices.

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).

In 2000, revenues from off-system gas sales increased compared to 1999 mostly because we sold more gas off-system at significantly higher prices.

In 1999, revenues from off-system gas sales were about the same compared to 1998.

Gas Purchased For Resale Expenses

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

In 2000, our gas costs increased compared to 1999 mostly because we bought more gas for off-system sales and all of the gas purchased was at a higher price due to the significant increase in natural gas prices during the year.

In 1999, actual gas costs increased compared to 1998 mostly because we sold more gas.

Other Gas Operating Expenses

In 2000 and 1999, other gas operating expenses were about the same compared to the respective prior year.

Other Nonregulated Businesses

Earnings

	2000	1999	1998
	(In millions, except per share amounts)		
Revenues	$740.3	$858.1	$583.0
Operating expenses	638.0	821.5	569.4
Depreciation and amortization	23.0	23.5	13.9
Taxes other than income taxes	4.3	3.9	4.6
Income (loss) from operations	$ 75.0	$ 9.2	$ (4.9)
Net income (loss)	$ 5.6	$(24.1)	$(32.9)
Total earnings per share before nonrecurring charges included in operations:	$ .04	$ .01	$ (.09)
Write-down of power project	--	(.03)	--
Write-down of financial investment	--	(.11)	--
Write-down of real estate and senior-living investments	--	(.04)	(.10)
Write-off of energy services investment	--	--	(.04)
Earnings per share	$ .04	$ (.17)	$ (.23)

Above amounts include intercompany transactions eliminated in our Consolidated Financial Statements. Note 2 provides a reconciliation of operating results by segment to our Consolidated Financial Statements.

In 2000, earnings from our other nonregulated businesses increased compared to 1999 mostly because of better market performance of certain of our financial investments. In addition, in 1999, we wrote-down a financial investment, our investment in a generating company in Bolivia, and certain senior-living facilities, which had negative impacts in that year. These increases were offset partially by lower earnings from our Latin American operation primarily due to increased operating expenses in Guatemala.

In 1999, earnings from our other nonregulated businesses increased compared to 1998 mostly because of higher earnings from our Latin American and real estate and senior-living facilities operations. This increase was offset partially by lower earnings from our financial investments operation.

In 1999, earnings from our Latin American operation increased mostly because of higher earnings from the electric distribution company in Panama compared to 1998. In October 1998, an investment group, in which subsidiaries of our Latin American operation hold an 80% interest, purchased 51% of the Panamanian company. This was offset partially by a $4.5 million after-tax write-down of our investment in a generating company in Bolivia to reflect the current fair value of this investment. This write-down was a result of our December 1999 decision to exit the Latin American portion of our business as part of our strategy to improve our competitive position.

In 1999, earnings from our real estate and senior-living facilities operation increased compared to 1998 mostly because of:

. a $15.4 million after-tax write-down of its investment in Church Street Station, an entertainment, dining, and retail complex in Orlando, Florida in 1998 that negatively impacted earnings that year, and
. an increase in earnings from its investment in Corporate Office Properties Trust (COPT) in 1999. We discuss the investment in COPT in Note 3.

This increase was offset partially by a $5.8 million after-tax write-down of certain senior-living facilities related to the proposed sale of these facilities in 1999 as discussed below.

Additionally, in 1998, our energy products and services operation recorded a $5.5 million after-tax write-off of an investment in, and certain of our product inventory from, an automated electric distribution equipment company.

In 1999, our financial investments operation announced that it would exchange its shares of common stock in Capital Re, an insurance company, for common stock of ACE, another insurance company, as part of a business combination whereby ACE would acquire all of the outstanding capital stock of Capital Re. As a result, our financial investments operation wrote-down its $94.2 million investment in Capital Re stock by $16.0 million after-tax to reflect the closing price of the business combination. This write-down of Capital Re was offset partially by better market performance of other financial investments in 1999 compared to 1998.

In 1999, our senior-living facilities operation entered into an agreement to sell all but one of its senior-living facilities to Sunrise Assisted Living, Inc. Under the terms of the agreement, Sunrise was to acquire twelve of our existing senior-living facilities, three facilities under construction, and several sites under development for $72.2 million in cash and $16.0 million in debt assumption. We could not reach an agreement on financing issues that subsequently arose, and the agreement was terminated in November 1999. As a result, our senior-living facilities operation engaged a third-party management company to manage its portfolio. However, our senior-living facilities operation recorded a $5.8 million after-tax write-down related to the proposed sale.

Most of Constellation Real Estate Group's real estate and senior-living projects are in the Baltimore-Washington corridor. The area has had a surplus of available land in recent years and as a result these projects have been economically hurt.

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Constellation Real Estate's projects have continued to incur carrying costs and depreciation over the years. Additionally, this operation has been charging interest payments to expense rather than capitalizing them for some undeveloped land where development activities have stopped. These carrying costs, depreciation, and interest expenses have decreased earnings and are expected to continue to do so.

Cash flow from real estate and senior-living operations has not been enough to make the monthly loan payments on some of these projects. Cash shortfalls have been covered by cash obtained from the cash flows of, or additional borrowings by, other nonregulated subsidiaries.

We consider market demand, interest rates, the availability of financing, and the strength of the economy in general when making decisions about our real estate and senior-living projects. If we were to decide to sell our projects, we could have write-downs. In addition, if we were to sell our projects in the current market, we would have losses which could be material, although the amount of the losses is hard to predict. Depending on market conditions, we could also have material losses on any future sales.

Our current real estate and senior-living strategy is to hold each project until we can realize a reasonable value for it. Under accounting rules, we are required to write down the value of a project to market value in either of two cases. The first is if we change our intent about a project from an intent to hold to an intent to sell and the market value of that project is below book value. The second is if the expected cash flow from the project is less than the investment in the project.

Consolidated Nonoperating Income and Expenses

Fixed Charges

In 2000, fixed charges increased $16.4 million compared to 1999 mostly because we had more debt outstanding.

In 1999, fixed charges decreased $5.6 million compared to 1998 mostly because we had less BGE preference stock outstanding.

Income Taxes

In 2000, our total income taxes increased $43.7 million compared to 1999 mostly because we had higher taxable income from our nonregulated businesses and an increase in state and local taxes as a result of comprehensive changes to these laws. This increase was offset partially by lower taxable income at BGE. We discuss the comprehensive tax law changes in Note 4.

In 1999, income taxes increased $8.7 million compared to 1998 because we had higher taxable income from both our regulated utility operations and our nonregulated businesses.

FINANCIAL CONDITION

Cash Flows

	2000	1999	1998
	(In millions)		
Cash provided by (used in):			
Operating activities	$ 850.9	$ 679.0	$ 799.8
Investing activities	(1,106.5)	(615.1)	(711.3)
Financing activities	345.6	(144.9)	(77.4)

In 2000 and 1999, cash provided by operations changed compared to the respective prior year mostly because of changes in working capital requirements.

In 2000, we used more cash for investing activities compared to 1999 mostly due to substantial increases in our domestic merchant energy capital expenditures to support our growth initiatives.

In 1999, we used less cash for investing activities compared to 1998 mostly due to lower investments in Latin American power projects and in the real estate and senior-living facilities operation. This was offset partially by a $97.7 million increase in the investment in Orion, an increase in our investment in domestic power projects, and an increase in capital expenditures by our regulated utility business.

In 2000, we had more cash from financing activities compared to 1999 mostly because we issued more long-term debt and common stock. This was offset partially by an increase in net maturities of short-term borrowings and we repaid more long-term debt.

In 1999, we used more cash for financing activities compared to 1998 mostly because we repaid more long-term debt and issued less long-term debt and common stock. This was offset partially by a decrease in the redemption of BGE preference stock and an increase in our net short-term borrowings.

Security Ratings

Independent credit-rating agencies rate Constellation Energy 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. Constellation Energy and BGE's securities ratings at December 31, 2000 were:

	Standard & Poors Rating Group	Moody's Investors Service	Fitch IBCA
Constellation Energy			
Unsecured Debt	A-	A3	A-
BGE			
Mortgage Bonds	AA-	A1	A+
Unsecured Debt	A	A2	A
Trust Originated Preferred Securities and Preference Stock	A-	"a2"	A-

CAPITAL RESOURCES

Our business requires a great deal of capital. Our actual consolidated capital requirements for the years 1998 through 2000, along with the estimated annual amounts for the years 2001 through 2003, are shown in the table below.

We will continue to have cash requirements for:

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

Capital requirements for 2001 through 2003 include estimates of funding 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 development,
. 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.

Effective July 1, 2000, all of BGE's generation assets were transferred to nonregulated subsidiaries of Constellation Energy. The discussion and table for capital requirements below include these generation assets as part of the utility's regulated electric business through June 30, 2000. After that date, the capital requirements are included in the domestic merchant energy business.

	1998	1999	2000	2001
			(In millions)	
Nonregulated Capital Requirements:				
Investment requirements:				
Domestic merchant energy	$ 318	$ 260	$ 801*	$1,420
Other	7	18	29	50
Total investment requirements	325	278	830	1,470
Retirement of long-term debt	232	189	295	406**
Total nonregulated capital requirements	557	467	1,125	1,876
Utility Capital Requirements:				
Capital expenditures:				
Regulated electric				
Generation (including nuclear fuel)	154	170	95	--
Transmission and distribution	161	173	170	174
Total regulated electric	315	343	265	174
Regulated gas	55	59	55	53
Common	35	34	30	32
Total capital expenditures	405	436	350	259
Retirement of long-term debt and redemption of preference stock	222	342	402	394
Total utility capital requirements	627	778	752	653
Total capital requirements	$1,184	$1,245	$1,877	$2,529

*Effective July 1, 2000, includes $110.6 million for electric generation and nuclear fuel formerly part of BGE's regulated electric business.
**Amount does not include $1.2 billion in Constellation Energy debt that would be redeemed at or prior to business separation.

Capital Requirements

Domestic Merchant Energy Business

Our domestic merchant energy business will require additional funding for growing its power marketing operation and developing and acquiring power projects.

Our domestic merchant energy business investment requirements include the planned purchase of the Nine Mile Point nuclear power plant for $815 million, including fuel, and the planned construction of 1,100 megawatts of peaking capacity in the Mid-Atlantic and Mid-West regions which are expected to be operational by the summer of 2001. An additional 6,700 megawatts of peaking and combined cycle production facilities are scheduled for completion in 2002 and beyond in various regions of North America. Longer range, our plans are to control approximately 30,000 megawatts of generation capacity by 2005. For further information see the Strategy section.

Electric Generation

Electric construction expenditures for our regulated electric business include improvements to generating plants and costs for replacing the steam generators at Calvert Cliffs through June 30, 2000. Thereafter, these expenditures are reflected in our domestic merchant energy business.

In March 2000, we received the license extension from the Nuclear Regulatory Commission (NRC) that extends our operating licenses at Calvert Cliffs to 2034 for Unit 1 and 2036 for Unit 2. If we do not replace the steam generators, we will not be able to operate these units through our operating license periods. We expect the steam generator replacement to occur during the 2002 refueling outage for Unit 1 and during the 2003 refueling outage for Unit 2. We estimate these Calvert Cliffs' costs to be:

- $ 63 million in 2001,
- $ 91 million in 2002, and
- $ 60 million in 2003.

Additionally, our estimates of future electric generation construction expenditures include the costs of complying with Environmental Protection Agency (EPA) and State of Maryland nitrogen oxides emissions (NOx) reduction regulations as follows:

- $ 85 million in 2001,
- $ 37 million in 2002, and
- $ 7 million in 2003.

We discuss the NOx regulations and timing of expenditures in Note 10.

Regulated Electric Transmission and Distribution and Gas

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

Funding for Capital Requirements

On October 23, 2000, we announced initiatives designed to advance our growth strategies in the domestic merchant energy business and a change in our common stock dividend policy effective April 2001, as discussed in the Strategy section.

As part of these initiatives, we expect to redeem all of the outstanding debt at Constellation Energy at or prior to the separation of our domestic merchant energy business and remaining businesses. The redemption will occur through a combination of open market purchases, tender offers, and redemption calls. We expect to fund this redemption with short-term debt or other credit facilities, and to refinance this debt longer term after the separation.

On March 26, 2001, we issued 12 million shares of common stock with net proceeds of $471.4 million.

Domestic Merchant Energy Business

Funding for the expansion of our domestic merchant energy business is expected from internally generated funds, commercial paper, long-term debt, equity, leases, and other financing instruments issued by Constellation Energy and its subsidiaries. Specifically related to the Nine Mile Point acquisition, one-half of the purchase price, or $407.5 million, is due at the closing of the transaction and the remainder is being financed through the sellers in a note to be repaid over five years with an interest rate of 11.0%. We expect to close the transaction with funds from available sources at that time. Payments on the note over the five years are expected to come from internally generated funds. Longer term, we expect to fund our growth and operating objectives with a mixture of debt and equity with an overall goal of maintaining an investment grade credit profile.

When our domestic merchant energy business separates from our remaining businesses, it initially expects to reinvest its earnings to fund its growth and not to pay a dividend.

Constellation Energy has a commercial paper program where it can issue up to $500 million in short-term notes to fund its nonregulated businesses. To support its commercial paper program, Constellation Energy maintains two revolving credit agreements totaling $565 million, of which one facility can also issue letters of credit. In addition, Constellation Energy has access to interim lines of credit as required from time to time to support its outstanding commercial paper.

BGE

Funding for utility capital expenditures is expected from internally generated funds, 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.

At December 31, 2000, FERC authorized BGE to issue up to $700 million of short-term borrowings, including commercial paper. In addition, BGE maintains $193 million in annual committed bank lines of credit and has $25 million in bank

revolving credit agreements to support the commercial paper program. In addition, BGE has access to interim lines of credit as required from time to time to support its outstanding commercial paper.

During the three years from 2001 through 2003, we expect our regulated utility business to provide at least 110% of the cash needed to meet the capital requirements for its operations, excluding cash needed to retire debt.

Other Nonregulated Businesses

BGE Home Products & Services may meet capital requirements through sales of receivables. ComfortLink has a revolving credit agreement totaling $50 million to provide liquidity for short-term financial needs.

If we can get a reasonable value for our real estate projects, senior-living facilities, Latin American operation, 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. We discuss the real estate and senior-living facilities operation and market conditions in the Other Nonregulated Businesses section.

We discuss our short-term borrowings in Note 7 and long-term debt in Note 8.

MARKET RISK

We are exposed to market risk, including changes in interest rates, certain commodity prices, equity prices, and foreign currency. To manage our market risk, we may enter into various derivative instruments including swaps, forward contracts, futures contracts, and options. Effective July 1, 2000, we are subject to additional market risk associated with the purchase and sale of energy as discussed in the Current Issues section. We discuss our market risk further in Note 1. 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. The following table provides information about our obligations that are sensitive to interest rate changes:

Principal Payments and Interest Rate Detail by Contractual Maturity Date

	2001	2002	2003	2004	2005	Thereafter
				(Dollar amounts in millions)		
Long-term debt						
Variable-rate debt	$317.6	$208.0	$200.2	$ 7.6	$ 5.4	$ 593.0
Average interest rate	6.97%	7.30%	7.26%	8.42%	8.62%	5.99%
Fixed-rate debt	$482.5	$327.1	$286.3	$156.0	$347.6	$1,140.0
Average interest rate	7.08%	7.01%	6.50%	5.80%	7.72%	6.85%

Commodity Price Risk

We are exposed to the impact of market fluctuations in the price and transportation costs of electricity, natural gas, and other commodities.

Domestic Merchant Energy Business

Our domestic merchant energy business is exposed to market risk from the power marketing operation of Constellation Power Source and from our electric generation operations. Constellation Power Source manages the commodity price risk inherent in its power marketing activities on a portfolio basis, subject to established trading and risk management policies. Commodity price risk arises from the potential for changes in the value of energy commodities and related derivatives due to: changes in commodity prices, volatility of commodity prices, and fluctuations in interest rates. A number of factors associated with the structure and operation of the electricity market significantly influence the level and volatility of prices for energy commodities and related derivative products. These factors include:

- seasonal changes in demand,
- hourly fluctuations in demand 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.

Constellation Power Source uses various methods, including a value at risk model, to measure its exposure to market risk. Value at risk is a statistical model that attempts to predict risk of loss based on historical market price and volatility data. Constellation Power Source calculates value at risk using a variance/covariance technique that models option positions using a linear approximation of their value. Additionally, Constellation Power Source estimates variances and correlation using historical market movements over the most recent rolling three-month period.

The value at risk amount represents the potential loss in the fair value of assets and liabilities from trading activities over a one-day holding period with a 99.6% confidence level. Using this confidence level, Constellation Power Source would expect a one-day change in fair value greater than or equal to the daily value at risk at least once per year. Constellation Power Source's value at risk was $13.7 million as of December 31, 2000 compared to $7.2 million as of December 31, 1999. The average, high, and low value at risk for the year ended December 31, 2000 was $13.1 million, $24.3 million, and $6.3 million, respectively.

Constellation Power Source's value at risk calculation includes all assets and liabilities from its power marketing and trading activities, including energy commodities and derivatives that do not require cash settlements. We believe that this represents a more complete calculation of our value at risk.

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 assets and liabilities from power marketing and trading activities could differ from the calculated value at risk, and such changes could have a material impact on our financial results. Please refer to the Forward Looking Statements section.

We discuss Constellation Power Source's operation in the Domestic Merchant Energy Business section and in Note 1.

Our domestic merchant energy business conducts electric generation operations primarily through Constellation Power Source Generation, Calvert Cliffs, and Constellation Power. Presently, the majority of the generating capacity controlled by our domestic merchant energy business is used to provide standard offer service to BGE. However, beginning in July 2002, we expect approximately 1,000 megawatts of industrial customer load will leave standard offer service. The remainder of the standard offer service arrangement with BGE terminates on June 30, 2003. Additionally, we plan to expand our generation operations as discussed in the Strategy section.

As a result, our domestic merchant energy business has a substantial and increasing amount of generating capacity that is subject to future changes in wholesale electricity prices and has fuel requirements that are subject to future changes in coal, natural gas, and oil prices. 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.

Constellation Power Source manages the commodity price risk of our electric generation operations as part of its overall portfolio. Additionally, the domestic merchant energy business may enter into fixed-price contracts to hedge a portion of its exposure to future electricity and fuel commodity price risk.

Regulated Electric Business

The standard offer service arrangement between BGE and Constellation Power Source ends June 30, 2003. Under the Restructuring Order, 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. As a result, BGE will be subject to commodity price risk beginning July 1, 2003 upon termination of the existing standard offer arrangement. In accordance with the Restructuring Order, BGE will competitively bid the standard offer service supply for the remaining period of the rate freeze subsequent to June 30, 2003. During the remaining period of BGE's rate freeze, BGE will be unable to pass through to its customers any increase in the market price of electricity it must purchase to meet the standard offer service load. Our regulated electric business is evaluating various alternatives to minimize the market risk after June 30, 2003.

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, 2000 and 1999, our exposure to commodity price risk for our regulated gas business was not material.

Credit Risk

We are exposed to credit risk, primarily through Constellation Power Source. Credit risk is the loss that may result from a counterparty's nonperformance. Constellation Power Source uses credit policies to control its 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. However, due to the possibility of extreme volatility in the prices of electricity 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 Constellation Power Source had contracted for), Constellation Power Source could sustain a loss that could have a material impact on our financial results.

Our domestic merchant energy business sells electricity to two California investor-owned utilities under long-term power purchase agreements that recently were downgraded by rating agencies to below investment grade. We discuss the credit and other exposures under these agreements in the Current Issues section.

Equity Price Risk

We are exposed to price fluctuations in equity markets primarily through our financial investments operation and our nuclear decommissioning trust fund. We are required by the NRC to maintain a trust to fund the costs of decommissioning Calvert Cliffs. We believe our exposure to fluctuations in equity prices will not have a material impact on our financial results. We discuss our nuclear decommissioning trust fund in more detail in Note 1. We also describe our financial investments in more detail in Note 3.

Foreign Currency Risk

We are exposed to foreign currency risk primarily through our Latin American operation. Our Latin American operation has $255.9 million invested in international power generation and distribution projects as of December 31, 2000. To manage our exposure to foreign currency risk, the majority of our contracts are denominated in or indexed to the U.S. dollar. At December 31, 2000 and 1999, foreign currency risk was not material. We discuss our international projects in the Other Nonregulated Businesses section.

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 the Companies is responsible for the information and representations in the Companies' financial statements. The Companies prepare the financial statements in accordance with accounting principles generally accepted in the United States of America based upon available facts and circumstances and management's best estimates and judgments of known conditions.

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 Chairman of the Board, 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 four outside 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.

/s/ Christian H. Poindexter   /s/ David A. Brune

Christian H. Poindexter	David A. Brune
Chairman of the Board	Chief Financial Officer
and Chief Executive 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 14(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, 2000 and 1999, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2000 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 14(a) 2. of this Form 10-K present 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 Baltimore Gas and Electric Company as of December 31, 1998, 1997 and 1996, and the related consolidated statements of income, comprehensive income, cash flows, common shareholders' equity and income taxes for the years ended December 31, 1997 and 1996 (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, 2000, 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, 2000, is fairly stated, in all material respects, in relation to the consolidated financial statements from which it has been derived.

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Baltimore, Maryland
January 17, 2001

CONSOLIDATED STATEMENTS OF INCOME -- CONSTELLATION ENERGY GROUP INC. AND SUBSIDIARIES

Year Ended December 31,	2000	1999	199
	(In millions, except per share am		
Revenues			
Nonregulated revenues	$1,140.0	$1,050.9	$ 717.
Regulated electric revenues	2,134.7	2,258.8	2,219.
Regulated gas revenues	603.8	476.5	449.
Total revenues	3,878.5	3,786.2	3,386.
Expenses			
Operating expenses	2,347.3	2,349.2	2,053.
Depreciation and amortization	470.0	449.8	375.
Taxes other than income taxes	221.0	227.3	219.
Total expenses	3,038.3	3,026.3	2,647.
Income from Operations	840.2	759.9	738.
Other Income	6.6	7.9	5.
Income Before Fixed Charges and Income Taxes	846.8	767.8	744.
Fixed Charges			
Interest expense (net)	258.2	241.5	238.
BGE preference stock dividends	13.2	13.5	21.
Total fixed charges	271.4	255.0	260.
Income Before Income Taxes	575.4	512.8	483.
Income Taxes	230.1	186.4	177.
Income Before Extraordinary Item	345.3	326.4	305.
Extraordinary Loss, Net of Income Taxes of $30.4 (see Note 4)	--	(66.3)	-
Net Income	$ 345.3	$ 260.1	$ 305.
Earnings Applicable to Common Stock	$ 345.3	$ 260.1	$ 305.
Average Shares of Common Stock Outstanding	150.0	149.6	148.
Earnings Per Common Share and Earnings Per Common Share-- Assuming Dilution Before Extraordinary Item	$ 2.30	$ 2.18	$ 2.0
Extraordinary Loss	--	(.44)	-
Earnings Per Common Share and Earnings Per Common Share--Assuming Dilution	$ 2.30	$ 1.74	$ 2.0

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME -- CONSTELLATION ENERGY GROUP INC. AND SUBSIDIARI

Year Ended December 31,	2000	1999	199
		(In millions)	
Net Income	$345.3	$260.1	$305.
Other comprehensive income/(loss), net of taxes	22.1	(6.2)	1.

Comprehensive Income	$367.4	$253.9	$307.

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

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CONSOLIDATED BALANCE SHEETS -- CONSTELLATION ENERGY GROUP INC. AND SUBSIDIARIES

At December 31,	2000	1999
	(In millions)	
Assets		
Current Assets		
Cash and cash equivalents	$ 182.7	$ 92.7
Accounts receivable (net of allowance for uncollectibles of $21.3 and $34.8, respectively)	738.5	578.5
Trading securities	189.3	136.5
Assets from energy trading activities	2,056.5	312.1
Fuel stocks	78.2	94.9
Materials and supplies	151.3	149.1
Prepaid taxes other than income taxes	73.5	72.4
Other	32.7	54.0
Total current assets	3,502.7	1,490.2
Investments and Other Assets		
Real estate projects and investments	290.3	310.1
Investments in power projects	517.5	513.9
Financial investments	161.0	145.4
Nuclear decommissioning trust fund	228.7	217.9
Net pension asset	93.2	99.5
Investment in Orion Power Holdings, Inc.	192.0	105.7
Other	123.0	154.3
Total investments and other assets	1,605.7	1,546.8
Property, Plant and Equipment		
Regulated property, plant and equipment		
Plant in service	4,780.3	8,620.1
Construction work in progress	75.3	222.3
Plant held for future use	4.5	13.0
Total regulated property, plant and equipment	4,860.1	8,855.4
Nonregulated generation property, plant and equipment	5,279.9	374.7
Other nonregulated property, plant and equipment	173.8	152.7
Nuclear fuel (net of amortization)	128.3	133.8
Accumulated depreciation	(3,798.1)	(3,559.1)
Net property, plant and equipment	6,644.0	5,957.5

Deferred Charges		
Regulatory assets (net)	514.9	637.4
Other	117.3	51.9
Total deferred charges	632.2	689.3
Total Assets	$12,384.6	$ 9,683.8

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,	2000	1999
	(In millions)	
Liabilities and Capitalization		
Current Liabilities		
Short-term borrowings	$ 243.6	$ 371.5
Current portion of long-term debt	906.6	808.3
Accounts payable	695.9	365.1
Liabilities from energy trading activities	1,586.8	163.8
Dividends declared	66.5	66.1
Accrued taxes	38.2	19.2
Other	212.6	209.4
Total current liabilities	3,750.2	2,003.4
Deferred Credits and Other Liabilities		
Deferred income taxes	1,339.5	1,288.8
Postretirement and postemployment benefits	265.2	269.8
Deferred investment tax credits	101.4	109.6
Other	426.0	253.8
Total deferred credits and other liabilities	2,132.1	1,922.0
Capitalization		
Long-term debt	3,159.3	2,575.4
BGE preference stock not subject to mandatory redemption	190.0	190.0
Common shareholders' equity	3,153.0	2,993.0
Total capitalization	6,502.3	5,758.4

Commitments, Guarantees, and Contingencies (see Note 10)		
Total Liabilities and Capitalization	$12,384.6	$9,683.8

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

CONSOLIDATED STATEMENTS OF CASH FLOWS--CONSTELLATION ENERGY GROUP INC. AND SUBSIDIARIES

Year Ended December 31,	2000	
		(In
Cash Flows From Operating Activities		
Net income	$ 345.3	$ 2
Adjustments to reconcile to net cash provided by operating activities		
Extraordinary loss	--	
Depreciation and amortization	524.8	5
Deferred income taxes	42.0	
Investment tax credit adjustments	(8.3)	
Deferred fuel costs	2.8	(
Accrued pension and postemployment benefits	27.9	
Gain on sale of subsidiaries	(13.3)	
Gain on sale of Orion Power Holdings, Inc. stock	(19.2)	
Deregulation transition cost	24.0	
Write-downs of real estate investments	--	
Write-down of financial investment	--	
Write-downs of power projects	--	
Equity in earnings of affiliates and joint ventures (net)	(5.3)	
Changes in assets from energy trading activities	(1,744.4)	(1
Changes in liabilities from energy trading activities	1,423.0	
Changes in other current assets	(176.6)	(2
Changes in other current liabilities	352.1	1
Other	76.1	
Net cash provided by operating activities	850.9	6
Cash Flows From Investing Activities		
Purchases of property, plant and equipment and other capital expenditures	(1,079.0)	(6
Investment in Orion	(101.5)	(
Contributions to nuclear decommissioning trust fund	(13.2)	(
Purchases of marketable equity securities	(80.8)	(
Sales of marketable equity securities	110.2	
Other investments	57.8	1
Net cash used in investing activities	(1,106.5)	(6
Cash Flows From Financing Activities		

Net (maturity) issuance of short-term borrowings	(127.9)	3
Proceeds from issuance of		
Long-term debt	1,374.0	3
Common stock	35.9	
Reacquisition of long-term debt	(697.0)	(5
Redemption of preference stock	--	
Common stock dividends paid	(250.7)	(2
Other	11.3	
Net cash provided by (used in) financing activities	345.6	(1
Net Increase (Decrease) in Cash and Cash Equivalents	90.0	(
Cash and Cash Equivalents at Beginning of Year	92.7	1
Cash and Cash Equivalents at End of Year	$ 182.7	$
Other Cash Flow Information		
Cash paid during the year for:		
Interest (net of amounts capitalized)	$ 268.2	$ 2
Income taxes	$ 184.7	$ 1

Noncash Investing and Financing Activities:

In 1998, Corporate Office Properties Trust (COPT) assumed approximately $62 million of Constellation Real Estate Group's (CREG) debt and issued to CREG 7.0 million common shares and 985,000 convertible preferred shares. In exchange, COPT received 14 operating properties and two properties under development from CREG.

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

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CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDERS' EQUITY--CONSTELLATION ENERGY GROUP INC. AND SUBSIDIARIES

Years Ended December 31, 2000, 1999, and 1998	Common Stock Shares	Common Stock Amount	Retained Earnings	Accumulated Other Comprehensive Income
	(Dollar amounts in millions, number of shares in			
Balance at December 31, 1997	147,667	$1,433.0	$1,432.5	$ 4.9
Net income			305.9	
Common stock dividend declared ($1.67 per share)			(248.1)	
Common stock issued	1,579	51.8		
Other		0.3		
Net unrealized gain on securities				1.8
Deferred taxes on net unrealized gain on securities				(0.6)

Balance at December 31, 1998	149,246	1,485.1	1,490.3	6.1
Net income			260.1	
Common stock dividend declared ($1.68 per share)			(251.3)	
Common stock issued	310	9.6		
Other		(0.7)		
Net unrealized loss on securities				(9.6)
Deferred taxes on net unrealized loss on securities				3.4
Balance at December 31, 1999	149,556	1,494.0	1,499.1	(0.1)
Net income			345.3	
Common stock dividend declared ($1.68 per share)			(251.8)	
Common stock issued	976	35.9		
Other		8.8	(0.3)	
Net unrealized gain on securities				33.9
Deferred taxes on net unrealized gain on securities				(11.8)
Balance at December 31, 2000	150,532	$1,538.7	$1,592.3	$22.0

See Notes to Consolidated Financial Statements.

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CONSOLIDATED STATEMENTS OF CAPITALIZATION -- CONSTELLATION ENERGY GROUP INC. AND SUBSIDIARIES

At December 31,

Long-Term Debt
 Long-term debt of Constellation Energy
  7 7/8% Notes, due April 1, 2005
  Floating rate notes, due April 4, 2003
  Extendible notes, due June 21, 2010
  Floating rate reset notes, due March 15, 2002

  Total long-term debt of Constellation Energy

 Long-term debt of nonregulated businesses
  Tax-exempt debt transferred from BGE effective July 1, 2000
   Pollution control loan, due July 1, 2011
   Port facilities loan, due June 1, 2013
   Adjustable rate pollution control loan, due July 1, 2014
   5.55% Pollution control revenue refunding loan, due July 15, 2014
   Economic development loan, due December 1, 2018
   6.00% Pollution control revenue refunding loan, due April 1, 2024
   Floating rate pollution control loan, due June 1, 2027
   5 1/2% Installment series, due July 15, 2002
  Loan under revolving credit agreement
  Mortgage and construction loans
   Floating rate mortgage notes and construction loans, due through 2005

Other mortgage notes ranging from 4.25% to 9.65% due July 31, 2001 to November 1, 2033
Unsecured notes
Total long-term debt of nonregulated businesses
First Refunding Mortgage Bonds of BGE
5 1/2% Series, due July 15, 2000 transferred to nonregulated businesses effective July 1, 2000
8 3/8% Series, due August 15, 2001
7 1/4% Series, due July 1, 2002
6 1/2% Series, due February 15, 2003
6 1/8% Series, due July 1, 2003
5 1/2% Series, due April 15, 2004
Remarketed floating rate series, due September 1, 2006
7 1/2% Series, due January 15, 2007
6 5/8% Series, due March 15, 2008
7 1/2% Series, due March 1, 2023
7 1/2% Series, due April 15, 2023
Tax-exempt debt transferred to nonregulated businesses effective July 1, 2000
Total First Refunding Mortgage Bonds of BGE
Other long-term debt of BGE
Floating rate reset notes, due October 19, 2001
Medium-term notes, Series B
Medium-term notes, Series C
Medium-term notes, Series D
Medium-term notes, Series E
Medium-term notes, Series G
Medium-term notes, Series H
6.75% Remarketable or redeemable securities, due December 15, 2012
Tax-exempt debt transferred to nonregulated businesses effective July 1, 2000
Total other long-term debt of BGE
BGE obligated mandatorily redeemable trust preferred securities of subsidiary trust holding solely 7.16% debentures of BGE due June 30, 2038
Unamortized discount and premium
Current portion of long-term debt
Total long-term debt

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

continued on next page

CONSOLIDATED STATEMENTS OF CAPITALIZATION -- CONSTELLATION ENERGY GROUP INC. AND SUBSIDIARIES

At December 31,

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	
6.97%, 1993 Series, 500,000 shares outstanding, not callable prior to October 1, 2003	
6.70%, 1993 Series, 400,000 shares outstanding, not callable prior to January 1, 2004	
6.99%, 1995 Series, 600,000 shares outstanding, not callable prior to October 1, 2005	
Total preference stock not subject to mandatory redemption	
Common Shareholders' Equity	
Common stock without par value, 250,000,000 shares authorized; 150,531,716 and 149,556,416 shares issued and outstanding at December 31, 2000 and 1999, respectively. (At December 31, 2000 166,893 shares were reserved for the Employee Savings Plan and 12,061,756 shares were reserved for the Shareholder Investment Plan.)	
Retained earnings	
Accumulated other comprehensive income (loss)	
Total common shareholders' equity	
Total Capitalization	

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

CONSOLIDATED STATEMENTS OF INCOME TAXES -- CONSTELLATION ENERGY GROUP INC. AND SUBSIDIARIES

Year Ended December 31,	2000	1999
	(Dollar amounts	
Income Taxes		
Current	$ 196.4	$ 182.0
Deferred		
Change in tax effect of temporary differences	50.4	9.6
Change in income taxes recoverable through future rates	3.4	--
Deferred taxes credited (charged) to shareholders' equity	(11.8)	3.4
Deferred taxes charged to expense	42.0	13.0
Investment tax credit adjustments	(8.3)	(8.6
Income taxes per Consolidated Statements of Income	$ 230.1	$ 186.4
Reconciliation of Income Taxes Computed at Statutory Federal Rate to Total Income Taxes		
Income before income taxes (excluding BGE preference stock dividends)	$ 588.6	$ 526.3
Statutory federal income tax rate	35%	35
Income taxes computed at statutory federal rate	206.0	184.2
Increases (decreases) in income taxes due to		

Depreciation differences not normalized on regulated activities	12.6	15.3
Allowance for equity funds used during construction	(0.9)	(2.2
Amortization of deferred investment tax credits	(8.3)	(8.6
Tax credits flowed through to income	(6.5)	(3.2
Amortization of deferred tax rate differential on regulated activities	(2.9)	(3.0
State income taxes	34.0	8.9
Other	(3.9)	(5.0
Total income taxes	$ 230.1	$ 186.4
Effective income tax rate	39.1%	35.4

At December 31,	2000
	(Dollar amounts
Deferred Income Taxes	
Deferred tax liabilities	
Net property, plant and equipment	$1,121.1
Income taxes recoverable through future rates	32.8
Deferred termination and postemployment costs	13.6
Deferred fuel costs	24.9
Leveraged leases	17.0
Energy trading activities	1,691.8
Deferred electric generation-related regulatory assets	93.7
Other	161.7
Total deferred tax liabilities	3,156.6
Deferred tax assets	
Accrued pension and postemployment benefit costs	76.5
Deferred investment tax credits	35.5
Nuclear decommissioning liability	28.2
Energy trading activities	1,510.6
Other	166.3
Total deferred tax assets	1,817.1
Deferred tax liability, net	$1,339.5

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

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CONSOLIDATED STATEMENTS OF INCOME

Baltimore Gas and Electric Company and Subsidiaries

Year Ended December 31,	2000
	(

Revenues	
Electric revenues	$ 2,135.2
Gas revenues	611.6
Nonregulated revenues	--
Total revenues	2,746.8
Expenses	
Operating Expenses:	
Electric fuel and purchased energy	870.5
Gas purchased for resale	350.7
Operations and maintenance	554.4
Nonregulated--selling, general, and administrative	--
Depreciation and amortization	367.9
Taxes other than income taxes	193.2
Total operating expenses	2,336.7
Income from Operations	410.1
Other Income	9.8
Income Before Fixed Charges and Income Taxes	419.9
Fixed Charges	
Interest expense (net)	187.2
Allowance for borrowed funds used during construction	(3.2)
Total fixed charges	184.0
Income Before Income Taxes	235.9
Income Taxes	
Current	142.1
Deferred	(44.4)
Investment tax credit adjustments	(5.3)
Total income taxes	92.4
Income Before Extraordinary Item	143.5
Extraordinary Loss, Net of Income Taxes of $30.4 (see Note 4)	--
Net Income	143.5
Preference Stock Dividends	13.2
Earnings Applicable to Common Stock	$ 130.3

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Baltimore Gas and Electric Company and Subsidiaries

Year Ended December 31,	2000
	(
Net Income	$ 143.5
Other comprehensive income/(loss), net of taxes	--
Comprehensive Income	$ 143.5

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,	2000
	(In
Assets	
Current Assets	
Cash and cash equivalents	$ 21.3
Accounts receivable (net of allowance for uncollectibles of $13.4 and $13.0 respectively)	413.0
Accounts receivable, affiliated companies	133.2
Note receivable, affiliated company	87.0
Fuel stocks	34.1
Materials and supplies	37.3
Prepaid taxes other than income taxes	44.9
Other	4.7
Total current assets	775.5
Investments and Other Assets	
Nuclear decommissioning trust fund	--
Net pension asset	100.2
Safe Harbor Water Power Corporation	--
Other	68.7
Total investments and other assets	168.9
Utility Plant	
Plant in service	
Electric	3,259.0
Gas	988.4
Common	532.9
Total plant in service	4,780.3
Accumulated depreciation	(1,700.3)
Net plant in service	3,080.0
Construction work in progress	75.3
Nuclear fuel (net of amortization)	--
Plant held for future use	4.5
Net utility plant	3,159.8
Deferred Charges	
Regulatory assets (net)	514.9
Other	35.1
Total deferred charges	550.0

Total Assets	$ 4,654.2

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,	2000
	(In millions)
Liabilities and Capitalization	
Current Liabilities	
Short-term borrowings	$ 32.1
Current portions of long-term debt and preference stock	567.6
Accounts payable	119.3
Accounts payable, affiliated companies	103.5
Customer deposits	44.4
Accrued taxes	25.0
Accrued interest	43.4
Accrued vacation costs	20.8
Other	29.6
Total current liabilities	985.7
Deferred Credits and Other Liabilities	
Deferred income taxes	508.7
Postretirement and postemployment benefits	231.2
Deferred investment tax credits	25.0
Decommissioning of federal uranium enrichment facilities	23.7
Other	23.2
Total deferred credits and other liabilities	811.8
Long-term Debt	
First refunding mortgage bonds of BGE	1,174.7
Other long-term debt of BGE	976.6
Company obligated mandatorily redeemable trust preferred securities of subsidiary trust holding solely 7.16% debentures of BGE due June 30, 2038	250.0
Long-term debt of nonregulated businesses	34.0
Unamortized discount and premium	(3.3)
Current portion of long-term debt	(567.6)
Total long-term debt	1,864.4

Preference Stock Not Subject to Mandatory Redemption	190.0
Common Shareholder's Equity	
Common stock	465.1
Retained earnings	337.2
Total common shareholder's equity	802.3
Total capitalization	2,856.7
Commitments, Guarantees, and Contingencies (see Note 10)	
Total Liabilities and Capitalization	$ 4,654.2

See Notes to Consolidated Financial Statements.

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

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CONSOLIDATED STATEMENTS OF CASH FLOWS
Baltimore Gas and Electric Company and Subsidiaries

Year Ended December 31,	2000
Cash Flows From Operating Activities	
Net income	$ 143.5
Adjustments to reconcile to net cash provided by operating activities	
Extraordinary loss	--
Depreciation and amortization	393.6
Deferred income taxes	(44.4)
Investment tax credit adjustments	(5.3)
Deferred fuel costs	2.8
Accrued pension and postemployment benefits	23.1
Write-downs of real estate investments	--
Allowance for equity funds used during construction	(2.6)
Equity in earnings of affiliates and joint ventures (net)	1.3
Changes in assets from energy trading activities	--
Changes in liabilities from energy trading activities	--
Changes in other current assets	(189.7)
Changes in other current liabilities	68.7
Other	5.7
Net cash provided by operating activities	396.7
Cash Flows From Investing Activities	
Utility construction expenditures (excluding AFC)	(309.5)
Nuclear fuel expenditures	(39.5)
Deferred conservation expenditures	(0.6)
Contributions to nuclear decommissioning trust fund	(8.8)
Purchases of marketable equity securities	--
Sales of marketable equity securities	--
Power projects	--
Other	0.7

Net cash used in investing activities		(357.7)
Cash Flows From Financing Activities		
Net (maturity) issuance of short-term borrowings		(96.9)
Proceeds from issuance of		
Long-term debt		377.3
Common stock		--
Reacquisition of long-term debt		(121.7)
Redemption of preference stock		--
Common stock dividends paid		--
Preferred and preference stock dividends paid		(13.2)
Distributions to Constellation Energy		(188.5)
Other		1.8
Net cash used in financing activities		(41.2)
Net (Decrease) Increase in Cash and Cash Equivalents		(2.2)
Cash and Cash Equivalents at Beginning of Year		23.5
Cash and Cash Equivalents at End of Year	$	21.3

Other Cash Flow Information

Cash paid during the year for:		
Interest (net of amounts capitalized)	$	184.7
Income taxes	$	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 pursuant to the Maryland PSC's Restructuring Order.

In 1998, Corporate Office Properties Trust (COPT) assumed approximately $62 million of Constellation Real Estate Group's (CREG) debt and issued to CREG 7.0 million common shares and 985,000 convertible preferred shares. In exchange, COPT received 14 operating properties and two properties under development from CREG.

See Notes to Consolidated Financial Statements.

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1 SIGNIFICANT ACCOUNTING POLICIES

Nature of Our Business

Constellation Energy(R) Group, Inc. (Constellation Energy) is a diversified North American energy company. Constellation Energy conducts its business through various subsidiaries that primarily include a domestic merchant energy business and Baltimore Gas and Electric Company (BGE(R)). Our domestic merchant energy business is focused mostly on power marketing and merchant generation in North America. BGE is an electric and gas public utility distribution 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 2.

References in this report to "we" and "our" are to Constellation Energy and its subsidiaries, collectively. Reference in this report to the "utility business" is to BGE.

On April 30, 1999, Constellation Energy became the holding company for BGE and Constellation(R) Enterprises, Inc. Constellation Enterprises was previously owned by BGE. BGE's outstanding common stock automatically became shares of common stock of Constellation Energy. BGE's debt securities, obligated mandatorily redeemable trust preferred securities, and preference stock remain securities of BGE, or its subsidiaries.

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.

This report is a combined report of Constellation Energy and BGE. The consolidated financial statements of Constellation Energy include the accounts of:

- Constellation Energy,
- BGE and its subsidiaries,
- Constellation Enterprises, Inc. and its subsidiaries, and
- Constellation Nuclear, LLC and its subsidiaries.

The consolidated financial statements of BGE include the accounts of:

- BGE
- ComfortLink, and
- BGE Capital Trust I.

As Constellation Enterprises and its subsidiaries were subsidiaries of BGE prior to April 30, 1999, they are included in the consolidated financial statements of BGE through that date.

The Equity Method

We usually use the equity method to report investments, corporate joint ventures, partnerships, and affiliated companies (including 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) provides 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 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. We summarize and discuss our regulatory assets and liabilities further in Note 5.

In 1997, the Financial Accounting Standards Board (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.

On November 10, 1999, the Maryland PSC issued a Restructuring Order that we believe provided sufficient details of the transition plan to competition for BGE's electric generation business to require BGE to discontinue the application of SFAS No. 71 for that portion of its business. Accordingly, in the fourth quarter of 1999, we adopted the provisions of SFAS No. 101, Regulated Enterprises--Accounting for the Discontinuation of FASB Statement No. 71 and EITF No. 97-4 for BGE's electric generation business. BGE's transmission and distribution business continues to meet the requirements of SFAS No. 71 as that business remains regulated. We discuss this further in Note 4.

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Revenues

Nonregulated Businesses

We record nonregulated revenues in our Consolidated Statements of Income in the period earned for services rendered, commodities or products delivered, or contracts settled.

Our subsidiary, Constellation Power Source, engages in power marketing activities, which include trading electricity, other energy commodities, and related derivatives (such as futures, forwards, options, and swaps). Constellation Power Source accounts for its activities using the mark-to-market method of accounting in accordance with EITF Issue 98-10, Accounting for Contracts Involved in Energy Trading and Risk Management Activities.

Under the mark-to-market method of accounting, we report:

- commodity positions and derivatives at fair value as "Assets from energy trading activities" or "Liabilities from energy trading activities" in our Consolidated Balance Sheets, and
- changes in fair value and net gains and losses from realized transactions as components of "Nonregulated revenues" in our Consolidated Statements of Income.

Changes in fair value result primarily from new transactions and the impact of price and interest rate movements.

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

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 use 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 (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. We either billed or refunded our customers that difference in the future. As a result of the Restructuring Order, the fuel rate was discontinued effective July 1, 2000. We discuss this further in Note 5.

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.

Risk Management

We are exposed to the impact of market fluctuations in the price and transportation costs of electricity, natural gas, and other commodities. Our domestic merchant energy and regulated gas businesses use derivative instruments to manage changes in their respective commodity prices. We discuss our risk management activities in more detail below.

Domestic Merchant Energy Business

Our domestic merchant energy business is exposed to market risk from the power marketing operation of Constellation Power Source and from our electric generation operations. Constellation Power Source manages the market risk inherent in its power marketing activities on a portfolio basis, subject to established trading and risk management policies. Constellation Power Source uses a variety of derivative instruments, 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) amount; and
- option contracts, which convey the right to buy or sell a commodity, financial instrument, or index at a predetermined price.

Market risk arises from the potential for changes in the value of energy commodities and related derivatives due to: changes in commodity prices, volatility of commodity prices, and fluctuations in interest rates. A number of factors associated with the structure and operation of the electricity market significantly influence the level and volatility of prices for energy commodities and related derivative products. These factors include:

- seasonal changes in demand,
- hourly fluctuations in demand 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.

Our domestic merchant energy business conducts electric generation operations primarily through Constellation Power Source Generation, Calvert Cliffs, and Constellation Power. Presently, the majority of the generating capacity controlled by our domestic merchant energy business is used to provide standard offer service to BGE. However, beginning in July 2002, we expect approximately 1,000 megawatts of industrial customer load will leave standard offer service. The remainder of the standard offer service arrangement with BGE terminates on June 30, 2003. Additionally, we plan to expand our generation operations.

As a result, our domestic merchant energy business has a substantial and increasing amount of generating capacity that is subject to future changes in wholesale electricity prices and has fuel requirements that are subject to future changes in coal, natural gas, and oil prices. 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.

Constellation Power Source manages the commodity price risk of our electric generation operations as part of its overall portfolio. Additionally, the domestic merchant energy business may enter into fixed-price contracts to hedge a portion of its exposure to future electricity and fuel commodity price risk.

At December 31, 2000, our domestic merchant energy business has several contracts to sell electricity for each calendar year beginning 2003 through 2010 at fixed prices to hedge a portion of the forecasted sales of electricity by our domestic merchant energy plants during these periods. At December 31, 2000, we recorded deferred hedge losses of $58 million in "Other deferred charges" in our Consolidated Balance Sheets. We will reclassify these deferred hedge losses to "Accumulated other comprehensive income" when we adopt SFAS No. 133 in 2001.

Regulated Electric Business

The standard offer service arrangement between BGE and Constellation Power Source ends June 30, 2003. Under the Restructuring Order, 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. As a result, BGE will be subject to commodity price risk beginning July 1, 2003 upon termination of the existing standard offer arrangement. In accordance with the Restructuring Order, BGE will competitively bid the standard offer service supply for the remaining period of the rate freeze subsequent to June 30, 2003. During the remaining period of BGE's rate freeze, BGE will be unable to pass through to its customers any increase in the market price of electricity it must purchase to meet the standard offer service load. Our regulated electric business is evaluating various alternatives to minimize the market risk after June 30, 2003.

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.

BGE's off-system gas sales activities represent trading activities under EITF 98-10. Accordingly, we use mark-to-market accounting to record these transactions. The trading activities relating to our off-system gas sales were not material at December 31, 2000 and 1999.

We defer, as unrealized gains or losses, the changes in fair value of the swap agreements under the market based rates incentive mechanism and the customers' portion of off-system gas sales in our Consolidated Balance Sheets. When amounts are paid under the agreements, we report the payments as gas costs in our Consolidated Statements of Income. We report the changes in fair value for the shareholders' portion of off-system gas sales in earnings as a component of gas costs.

Credit Risk

We are exposed to credit risk, primarily through Constellation Power Source. Credit risk is the loss that may result from a counterparty's nonperformance. Constellation Power Source uses credit policies to control its 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. However, due to the possibility of extreme volatility in the prices of electricity 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 Constellation Power Source had contracted for), Constellation Power Source could sustain a loss that could have a material impact on our financial results.

Taxes

We summarize our income taxes in our Consolidated Statements of Income Taxes. As you read this section, it may be helpful to refer to those statements.

Income Tax Expense

We have two categories of income taxes in our Consolidated Statements of Income--current and deferred. We describe each of these below.

Our current income tax expense consists solely of regular tax less applicable tax credits.

Our deferred income tax expense is equal to the changes in the net deferred income tax liability, excluding amounts charged or credited to common shareholders' equity. 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 credit associated with our regulated utility business and assets previously held by our regulated utility business in our Consolidated Balance Sheets. The investment tax credit is 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 credit 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 we do for income tax 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 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

As discussed in Note 4, tax legislation has made comprehensive changes to the state and local taxation of electric and gas utilities. State and local income taxes are included in "Income taxes" in our Consolidated Statements of Income.

Through December 31, 1999, we paid Maryland public service company franchise tax on our utility revenue from sales in Maryland instead of state income tax. We include the franchise tax in "Taxes other than income taxes" in our Consolidated Statements of Income.

Cash and Cash Equivalents

For the purpose of reporting our cash flows, we define cash equivalents as highly liquid investments that mature in three months or less.

At December 31, 2000, $112.5 million of the cash balance included in our Consolidated Balance Sheets was restricted under certain collateral arrangements for our power marketing operation.

Inventory

We report the majority of our fuel stocks and materials and supplies at average cost.

Real Estate Projects and Investments

In Note 3, we summarize the real estate projects and investments that are in our Consolidated Balance Sheets. The projects and investments consist of:

- land under development in the Baltimore-Washington corridor,
- a mixed-use planned-unit development, and
- an equity interest in Corporate Office Properties Trust, a real estate investment trust.

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

Financial Investments and Trading Securities

In Note 3, 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 specific identification 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 on the next page. 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 fund as available-for-sale securities. We include any unrealized gains or losses on the trust assets as a change in the decommissioning reserve. We describe the nuclear decommissioning trust and the reserve under the heading "Decommissioning Costs" later in this note.

In addition, our other nonregulated businesses classify some of their investments in marketable equity securities as available-for-sale securities. We include any unrealized gains or losses on these securities in "Accumulated other comprehensive income" in our Consolidated Statements of Common Shareholders' Equity and in the Consolidated Statements of Capitalization.

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

SFAS No. 121, Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of, applies particular requirements to some of our assets that have long lives (some examples are generating property and equipment and real estate). We determine if those assets are impaired by comparing their undiscounted expected future cash flows to their carrying amount in our accounting records. We recognize an impairment loss if the undiscounted expected future cash flows are less than the carrying amount of the asset. Additionally, we evaluate our equity-method investments to determine whether our investments have a loss in value that is considered other than a temporary decline in value. We use our best estimates to determine if there has been an impairment or decline in value other than temporary and consider various factors including forward price curves for energy, fuel costs, and operating costs. However, it is possible that future market prices and project costs could vary from those used in evaluating our long-lived assets and investments, and the impact of such variations could be material.

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. 121. Our original costs include:

- material and labor,
- contractor costs, and
- construction overhead costs and financing costs (where applicable).

We charge retired or otherwise disposed of property, plant and equipment that was depreciated under the composite, straight-line method to accumulated depreciation. This includes regulated utility property, plant and equipment and nonregulated generating assets previously owned by the regulated utility. When any other property, plant and equipment is retired, or otherwise disposed of, we reduce the property, plant and equipment balances and related accumulated depreciation and amortization amounts, and recognize 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.

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 $143 million at December 31, 2000 and $156 million at December 31, 1999.

The "Nonregulated generation property, plant and equipment" in our Consolidated Balance Sheets includes nonregulated generation construction work in progress of $901.8 million at December 31, 2000 and $97.7 million at December 31, 1999.

Depreciation Expense

We compute depreciation over the estimated useful lives of depreciable property using the:

- composite, straight-line rates (approved by the Maryland PSC for our regulated utility business) applied to the average investment in classes of depreciable property based on an average rate of approximately three percent per year,
- units of production method for certain nonregulated generation facilities, or
- straight-line method.

Amortization Expense

Amortization is an accounting process of reducing an amount in our Consolidated Balance Sheets evenly over a period of time. When we reduce amounts in our Consolidated Balance Sheets, we increase amortization expense in our Consolidated Statements of Income. An amount is considered fully amortized when it has been reduced to zero.

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 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.

We also 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.

Decommissioning Costs

We must accumulate a reserve for the costs that we expect to incur in the future to decommission the radioactive portion of Calvert Cliffs. We do this based on a sinking fund methodology. The Maryland PSC authorized us to include in the rates that we charge our customers decommissioning expense based on a facility-specific cost estimate so we can accumulate a decommissioning reserve of $521 million in 1993 dollars by the end of Calvert Cliffs' service life, adjusted to reflect expected inflation. We have reported the decommissioning reserve in

"Accumulated depreciation" in our Consolidated Balance Sheets. The total reserve was $310.1 million at December 31, 2000 and $287.5 million at December 31, 1999. Our contributions to the nuclear decommissioning trust funds were $13.2 million for 2000 and $17.6 million for 1999 and 1998.

To fund the costs we expect to incur to decommission the plant, we established an external decommissioning trust in accordance with Nuclear Regulatory Commission (NRC) regulations. We report the assets in the trust in "Nuclear decommissioning trust fund" in our Consolidated Balance Sheets. The NRC requires utilities to provide financial assurance that they will accumulate sufficient funds to pay for the cost of nuclear decommissioning based upon either a generic NRC formula or a facility-specific decommissioning cost estimate. We use the facility-specific cost estimate for funding these costs and providing the required financial assurance.

Capitalized Interest and Allowance for Funds Used During Construction

Capitalized Interest

With the issuance of the Restructuring Order, 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 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 9.40% for electric plant, 8.61% for gas plant, and 9.19% for common plant. We compound AFC annually.

Long-Term Debt

We defer (include as an asset or liability in our Consolidated Balance Sheets and exclude from our Consolidated Statements of Income) all costs related to the issuance of long-term debt. These costs include underwriters' commissions, discounts or premiums, and other costs such as legal, accounting, and regulatory fees, and printing costs. We amortize these costs 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.

When we incur gains or losses on debt that we retire prior to maturity in our nonregulated businesses, we record these gains or losses as an extraordinary item, if material.

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, among other things, future economic factors that are difficult to predict and are beyond management's control. As a result, actual amounts could differ from these estimates.

Reclassifications

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

Accounting Standards Issued

In June 1998, the FASB issued SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities. SFAS No. 133 establishes the accounting and disclosure standards for derivative financial instruments and hedging activities. In July 1999, the FASB issued SFAS No. 137 that delayed the effective date for SFAS No. 133 by one year. Therefore, we must adopt the provisions of SFAS No. 133 in our financial statements for the quarter ended March 31, 2001. In June 2000, the FASB issued SFAS No. 138, Accounting for Certain Derivative Instruments and Certain Hedging Activities, that amended certain provisions of SFAS No. 133 and addressed a limited number of implementation issues related to SFAS No. 133.

These statements require that we recognize all derivatives on the balance sheet at fair value. Changes in the value of derivatives that are not hedges must be recorded in earnings. We expect to use derivatives to hedge the risk of variations in future cash flows from forecasted purchases and sales of electricity. Changes in the value of these derivatives will be recognized in other comprehensive income until the forecasted transaction occurs. The ineffective portion of the change in fair value of a derivative being used as a hedge will be immediately recognized in earnings.

The cumulative effect on earnings of adopting these statements is not material for Constellation Energy. As of December 31, 2000, we entered into certain forward sales of electricity that were designated as cash flow hedges of forecasted transactions. We will record a reduction in other comprehensive income of approximately $35 million after-tax to reflect these cash flow hedges in accordance with these statements.

The cumulative effect of adopting these statements is not material for BGE.

2 INFORMATION BY OPERATING SEGMENT

In 1999, we reported three operating business segments--Electric, Gas, and Energy Services. In response to the deregulation of electric generation, we realigned our organization and combined our wholesale power marketing operation with our domestic plant development and operation activities to form a domestic merchant energy business.

In 2000, we revised our operating segments to reflect the realignments of our organization. Our new reportable operating segments are--Domestic Merchant Energy, Regulated Electric, and Regulated Gas:

- Our nonregulated domestic merchant energy business:
  - provides power marketing and risk management services,
  - develops, owns, and operates domestic power projects, and
  - provides nuclear consulting services.
- Our regulated electric business purchases, distributes and sells electricity, and
- Our regulated gas business purchases, transports, and sells natural gas.

We have restated certain prior period information for comparative purposes based on our new reportable operating segments.

Effective July 1, 2000, the financial results of the electric generation portion of our business are included in the domestic 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:

- develop, own, and operate international power projects in Latin America,
- provide energy products and services,
- sell and service electric and gas appliances, and heating and air conditioning systems, engage in home improvements, and sell natural gas through mass marketing efforts,
- provide cooling services,
- engage in financial investments, and
- develop, own and manage real estate and senior-living facilities.

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. A summary of information by operating segment is shown on the next page.

	Domestic Merchant Energy Business	Regulated Electric Business	Regulated Gas Business	Other Nonregulated Businesses	Unall Cor Item Elimi
			(In millions)		
2000					
Unaffiliated revenues	$ 415.4	$2,134.7	$ 603.8	$ 724.6	$
Intersegment revenues	576.6	0.5	7.8	15.7	(6
Total revenues	992.0	2,135.2	611.6	740.3	(6
Depreciation and amortization	80.9	319.9	46.2	23.0	
Equity in income of equity-method investees (a)	--	2.4	--	--	
Net interest expense	31.0	157.0	25.5	53.1	
Income tax expense	122.5	72.2	21.9	13.5	
Net income (b)	206.8	102.3	30.6	5.6	
Segment assets	6,753.3	3,453.4	1,028.8	1,299.5	(1
Capital expenditures	811.2	290.3	59.7	19.3	
1999					
Unaffiliated revenues	$ 212.9	$2,258.8	$ 476.5	$ 838.0	$
Intersegment revenues	--	1.2	11.6	20.1	(

Total revenues	212.9	2,260.0	488.1	858.1	(
Depreciation and amortization	5.0	376.4	44.9	23.5	
Equity in income of equity-method investees (a)	--	5.1	--	--	
Net interest expense	--	162.4	24.4	56.1	
Income tax expense (benefit)	29.4	149.2	18.1	(10.3)	
Extraordinary loss	--	66.3	--	--	
Net income (loss) (c)	52.4	198.8	33.0	(24.1)	
Segment assets	1,206.1	6,312.6	915.3	1,231.3	
Capital expenditures	260.9	366.8	69.2	17.3	
1998					
Unaffiliated revenues	$ 147.3	$2,219.2	$ 449.4	$ 570.5	$
Intersegment revenues	--	1.6	1.7	12.5	(
Total revenues	147.3	2,220.8	451.1	583.0	(
Depreciation and amortization	3.0	313.0	45.4	13.9	
Equity in income of equity-method investees (a)	--	5.0	--	--	
Net interest expense	--	164.9	23.6	50.7	
Income tax expense (benefit)	28.6	146.6	13.4	(10.9)	
Net income (loss) (d)	53.1	259.6	26.1	(32.9)	
Segment assets	885.3	6,342.8	934.6	1,275.2	
Capital expenditures	317.5	339.5	65.5	7.7	

(a) Our domestic merchant energy business records its equity in the income of equity method investees in unaffiliated revenues.

(b) Our regulated electric business recorded expense of $4.2 million related to employees that elected to participate in a Targeted Voluntary Special Early Retirement Program. In addition, our domestic merchant energy business recorded a $15.0 million deregulation transition cost incurred by our power marketing operation.

(c) Our regulated electric business recorded expense of $4.9 million related to Hurricane Floyd. Our domestic merchant energy business recorded $14.2 million for the write-off of two geothermal power plants. Our Latin American operation recorded $4.5 million for the write-down to reflect the fair value of our investment in a power project in Bolivia. Our financial investments operation recorded $16.0 million for the write-down of its investment in Capital Re stock to reflect the market value of this investment. Our real estate and senior-living facilities operation recorded $5.8 million for the write-down of certain senior-living facilities.

(d) Our domestic merchant energy business recorded $10.4 million for its share of earnings in a partnership. Our energy products and services operation recorded $5.5 million for the write-off of an energy services investment. Our real estate and senior-living facilities operation recorded $15.4 million for the write-down of a real estate project.

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3 INVESTMENTS

Real Estate Projects and Investments

Real estate projects and investments held by Constellation Real Estate Group (CREG), consist of the following:

At December 31,	2000	1999
	(In millions)	
Properties under development	$165.1	$197.8
Rental and operating properties (net of accumulated depreciation)	12.7	9.2
Equity interest in real estate investments	112.5	103.1
Total real estate projects and investments	$290.3	$310.1

In 1999, CREG sold Church Street Station--an entertainment, dining, and retail complex in Orlando, Florida--for $11.5 million, the approximate book value of the complex.

In 1998, CREG entered into an agreement with Corporate Office Properties Trust (COPT), a real estate investment trust based in Philadelphia, under which COPT assumed approximately $62 million of CREG's outstanding debt, paid CREG approximately $22.8 million in cash, and issued to CREG approximately 7.0 million common shares representing a 41.9% equity interest in COPT and 985,000 convertible preferred shares. Each convertible preferred share yields 5.5% per year, and is convertible after two years into 1.8748 common shares.

In exchange, COPT received 14 operating properties and two properties under development from CREG as well as certain other assets, options, and first refusal rights. These options and first refusal rights are related to approximately 91 acres of identified properties which are adjacent to operating properties acquired by COPT. At December 31, 2000, 30 acres remain under these options and first refusal rights with terms that range from one to three years.

In September 2000, CREG converted 984,307 preferred shares of COPT into approximately 1.8 million common shares of COPT.

Power Projects

Investments in power projects held by our domestic merchant energy business consist of the following:

At December 31,	2000	1999
	(In millions)	
East	$ 86.3	$ 85.1
West	419.8	416.5
Total domestic power projects	$506.1	$501.6

Our Domestic-West power projects include investments of $297.9 million in

2000 and $301.8 million in 1999 that sell electricity in California under power purchase agreements called "Interim Standard Offer No. 4" agreements. We discuss these projects further in Note 10.

In 1999, our domestic generation operation recorded a $14.2 million after-tax write-off of two geothermal power projects. These write-offs occurred because the expected future cash flows from the projects are less than the investment in the projects. For the first project, this resulted from the inability to restructure certain project agreements. For the second project, the water temperature of the geothermal resource used by one of the plants for production declined.

In 1998, our domestic generation operation recorded $10.4 million after-tax gain for its share of earnings in a partnership. The partnership recognized a gain on the sale of its ownership interest in a power sales contract.

Our Latin American operation held power projects of $11.4 million at December 31, 2000 and $12.3 million at December 31, 1999.

In 1999, our Latin American operation recorded a $4.5 million after-tax write-down to reflect the fair value of our investment in a generating company in Bolivia as a result of our international exit strategy.

Financial Investments

Financial investments held by Constellation Investments, Inc. consist of the following:

At December 31,	2000	1999
	(In millions)	
Marketable equity securities	$105.9	$ 84.2
Financial limited partnerships	32.7	35.8
Leveraged leases	22.4	25.4
Total financial investments	$161.0	$145.4

In 1999, our financial investments operation announced that it would exchange its shares of common stock in Capital Re, an insurance company, for common stock of ACE Limited (ACE), another insurance company, as part of a business combination whereby ACE would acquire all of the outstanding capital stock of Capital Re. As a result, our financial investments operation wrote-down its $94.2 million investment in Capital Re stock by $16.0 million after-tax to reflect the closing price of the business combination.

Investments Classified as Available-for-Sale

We classify our investments in the nuclear decommissioning trust fund as available-for-sale. In addition, we classify some of our other nonregulated businesses' marketable equity securities (shown above) as available-for-sale. 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.

At December 31, 2000	Amortized Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value
		(In millions)		
Marketable equity securities	$171.8	$68.9	$(2.2)	$238.5
Corporate debt and U.S. Government agency	26.1	0.1	(0.1)	26.1
State municipal bonds	61.3	2.3	(0.4)	63.2
Totals	$259.2	$71.3	$(2.7)	$327.8

At December 31, 1999	Amortized Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value
		(In millions)		
Marketable equity securities	$167.1	$42.8	$(2.1)	$207.8
Corporate debt and U.S. Government agency	14.4	--	--	14.4
State municipal bonds	74.2	--	(0.8)	73.4
Totals	$255.7	$42.8	$(2.9)	$295.6

The preceding tables include $34.7 million in 2000 and $40.5 million in 1999 of unrealized net gains associated with the nuclear decommissioning trust fund which are reflected as a change in the nuclear decommissioning trust fund on the Consolidated Balance Sheets.

Gross and net realized gains and losses on available-for-sale securities were as follows:

	2000	1999	1998
		(In millions)	
Gross realized gains	$54.5	$ 11.7	$ 4.2
Gross realized losses	(8.0)	(38.8)	(0.7)

Net realized gains (losses)	$46.5	$(27.1)	$ 3.5

The Corporate debt securities, U.S. Government agency obligations, and state municipal bonds mature on the following schedule:

At December 31, 2000	Amount
	(In millions)
Less than 1 year	$ 0.9
1-5 years	41.9
5-10 years	23.7
More than 10 years	22.8
Total maturities of debt securities	$89.3

4 RATE MATTERS AND ACCOUNTING IMPACTS OF DEREGULATION

On April 8, 1999, Maryland enacted the Electric Customer Choice and Competition Act of 1999 (the "Act") and accompanying tax legislation that significantly restructured Maryland's electric utility industry and modified the industry's tax structure. In the Restructuring Order discussed below, the Maryland PSC addressed the major provisions of the Act.

The tax legislation made comprehensive changes to the state and local taxation of electric and gas utilities. Effective January 1, 2000, the Maryland public service franchise tax was altered to generally include a tax equal to .062 cents on each kilowatt-hour of electricity and .402 cents on each therm of natural gas delivered for final consumption in Maryland. The Maryland 2% franchise tax on electric and natural gas utilities continues to apply to transmission and distribution revenue. Additionally, all electric and natural gas utility results are subject to the Maryland corporate income tax.

Beginning July 1, 2000, the tax legislation also provides for a two-year phase-in of a 50% reduction in the local personal property taxes on machinery and equipment used to generate electricity for resale and a 60% corporate income tax credit for real property taxes paid on those facilities.

On November 10, 1999, the Maryland PSC issued a Restructuring Order that resolved the major issues surrounding electric restructuring, accelerated the timetable for customer choice, and addressed the major provisions of the Act. The Restructuring Order also resolved the electric restructuring proceeding (transition costs, customer price protections, and unbundled rates for electric services) and a petition filed in September 1998 by the Office of People's Counsel (OPC) to lower our electric base rates. The major provisions of the Restructuring Order are:

- All customers, except a few commercial and industrial companies that have signed contracts with BGE, can choose their electric energy supplier beginning July 1, 2000. BGE will provide a standard offer service for customers that do not select an alternative supplier. In either case, BGE will continue to deliver electricity to all customers in areas traditionally served by BGE.

- BGE's electric base rates were frozen through June 30, 2000.
- BGE reduced residential base rates by approximately 6.5%, on average about $54 million a year, beginning July 1, 2000. These rates will not change before July 2006.
- Commercial and industrial customers have up to four service options that will fix electric energy rates and transition charges for a period that generally ranges from four to six years.
- BGE's electric fuel rate clause was discontinued effective July 1, 2000.
- Electric delivery service rates are frozen for a four-year period 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.

- BGE will recover $528 million after-tax of its potentially stranded investments and utility restructuring costs through a competitive transition charge on customers' bills. Residential customers will pay this charge for six years. Commercial and industrial customers will pay in a lump sum or over the four to six-year period, depending on the service option selected by each customer.
- Generation-related regulatory assets and nuclear decommissioning costs are included in delivery service rates effective July 1, 2000 and will be recovered on a basis approximating their amortization schedules prior to July 1, 2000.
- Effective July 1, 2000, BGE unbundled rates to show separate components for delivery service, competitive transition charges, standard offer services (generation), transmission, universal service, and taxes.
- Effective July 1, 2000, BGE transferred, at book value, its ten Maryland-based fossil and nuclear power plants and its partial ownership interest in two coal plants and a hydroelectric plant in Pennsylvania to nonregulated subsidiaries of Constellation Energy.
- BGE reduced its generation assets by $150 million pre-tax during the period July 1, 1999-June 30, 2000 to mitigate a portion of BGE's potentially stranded investments.
- Universal service is being provided for low-income customers without increasing their bills. BGE will provide its share of a statewide fund totaling $34 million annually.

As discussed in Note 1, EITF 97-4 requires that a company should cease applying 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 believe that the Restructuring Order provided sufficient details of the transition plan to competition for BGE's electric generation business to require BGE to discontinue the application of SFAS No. 71 for that portion of its business. Accordingly, in the fourth quarter of 1999, we adopted the provisions of SFAS No. 101 and EITF 97-4 for BGE's electric generation business.

SFAS No. 101 requires the elimination of the effects of rate regulation that have been recognized as regulatory assets and liabilities pursuant to SFAS No. 71. However, EITF 97-4 requires that regulatory assets and liabilities that will be recovered in the regulated portion of the business continue to be classified as regulatory assets and liabilities. The Restructuring Order provided for the creation of a single, new generation-related regulatory asset to be recovered through BGE's regulated transmission and distribution business. We discuss this further in Note 5.

Pursuant to SFAS No. 101, the book value of property, plant, and equipment may not be adjusted unless those assets are impaired under the provisions of SFAS No. 121. The process we used in evaluating and measuring impairment under the provisions of SFAS No. 121 involved two steps. First, we compared the net book value of each generating plant to the estimated undiscounted future net operating cash flows from that plant. An electric generating plant was considered impaired when its undiscounted future net operating cash flows were less than its net book value. Second, we computed the fair value of each plant that is determined to be impaired based on the present value of that plant's estimated future net operating cash flows discounted using an interest rate that considers the risk of operating that facility in a competitive environment. To the extent that the net book value of each impaired electric generation plant exceeded its fair value, we recorded a write-down.

Under the Restructuring Order, BGE will recover $528 million after-tax of its potentially stranded investments and utility restructuring costs through the competitive transition charge component of its customer rates beginning July 1, 2000. This recovery mostly relates to the stranded costs associated with BGE's Calvert Cliffs Nuclear Power Plant, whose book value was substantially higher than its estimated fair value. However, Calvert Cliffs was not considered impaired under the provisions of SFAS No. 121 since its estimated future undiscounted cash flows exceeded its book value. Accordingly, BGE did not record any impairment write-down related to Calvert Cliffs. However, we recognized after-tax impairment losses totaling $115.8 million associated with certain of our fossil plants under the provisions of SFAS No. 121.

BGE had contracts to purchase electric capacity and energy that became uneconomic upon the deregulation of electric generation. Therefore, we recorded a $34.2 million after-tax charge 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 terms of the contracts. In addition, BGE had deferred certain energy conservation expenditures that would not be recovered through its transmission and distribution business under the Restructuring Order. Accordingly, we recorded a $10.3 million after-tax charge to eliminate the regulatory asset previously established for these deferred expenditures.

At December 31, 1999, the total charge for BGE's electric generating plants that were impaired, losses on uneconomic purchased capacity and energy contracts, and deferred energy conservation expenditures was approximately $160.3 million after-tax.

BGE recorded approximately $94.0 million of the $160.3 million on its balance sheet. This consisted of a $150.0 million regulatory asset of its regulated transmission and distribution business, net of approximately $56.0 million of associated deferred income taxes. The regulatory asset was amortized as it was recovered from ratepayers through June 30, 2000. This accomplished the $150 million reduction of its generation plants required by the Restructuring Order.

We recorded an after-tax, extraordinary charge against earnings for approximately $66.3 million related to the remaining portion of the $160.3 million described above that was not recovered under the Restructuring Order.

5 REGULATORY ASSETS (NET)

As discussed in Note 1, the Maryland PSC provides 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,	2000	1999
	(In millions)	
Generation plant reduction recoverable in current rates	$ --	$ 75.0
Electric generation-related regulatory asset	267.8	286.6
Income taxes recoverable through future rates (net)	101.2	110.4
Deferred postretirement and postemployment benefit costs	38.7	41.9
Deferred conservation expenditures	5.8	12.9
Deferred environmental costs	28.8	31.3
Deferred fuel costs (net)	71.1	73.8
Other (net)	1.5	5.5
Total regulatory assets (net)	$514.9	$637.4

Generation Plant Reduction Recoverable in Current Rates

Under the Restructuring Order, BGE recorded a reduction to its generation plant of $150 million which it recovered through its rates between July 1, 1999 and June 30, 2000. In 1999, BGE recorded a $150 million regulatory asset for the required generation plant reduction that was amortized as it was recovered from ratepayers through June 30, 2000.

Electric Generation-Related Regulatory Asset

With the issuance of the Restructuring Order, 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. Pursuant to the Restructuring Order, 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.

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.

In 1999, we reclassified the electric generation-related portion of this net regulatory asset to the electric generation-related regulatory asset discussed earlier in this note.

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.

In 1999, we reclassified the electric generation-related portion of this regulatory asset to the electric generation-related regulatory asset discussed earlier in this note.

Deferred Conservation Expenditures

Deferred conservation expenditures include two components:

- operations costs (labor, materials, and indirect costs) associated with conservation programs approved by the Maryland PSC, which we are amortizing over periods of four to five years in accordance with the Maryland PSC's orders, and

- revenues we collected from customers in 1996 in excess of our profit limit under the conservation surcharge.

In 1999, we wrote off a portion of the unamortized electric conservation expenditures that will not be recovered under the Restructuring Order as discussed in Note 4.

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 10. 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 Maryland PSC's orders.

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Deferred Fuel Costs

As described in Note 1, deferred fuel costs are the difference between our actual costs of electric fuel, net purchases and sales of electricity, and 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.

We show our deferred fuel costs in the following table.

At December 31,	2000	1999
	(In millions)	
Electric	$42.3	$60.0
Gas	28.8	13.8
Deferred fuel costs (net)	$71.1	$73.8

Under the terms of the Restructuring Order, BGE's electric fuel rate clause was discontinued effective July 1, 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 are collecting this accumulated difference from customers over the twelve-month period beginning October 2000.

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.

Pension Benefits

We sponsor several defined benefit pension plans for our employees. A defined benefit plan specifies the amount of benefits a plan participant is to receive using information about the participant. Our 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, 2000 were mostly marketable equity and fixed income securities, and group annuity contracts.

In 1999, our Board of Directors approved the following amendments:

- eligible participants were allowed to choose between an enhanced version of the current benefit formula and a new pension equity plan (PEP) formula. Pension benefits for eligible employees hired after December 31, 1999 are based on a PEP formula, and
- pension and survivor benefits were increased for participants who retired prior to January 1, 1994 and for their surviving spouses.

The financial impacts of the amendments are included in the tables beginning on the next page.

Also during 1999, our Board of Directors approved a Targeted Voluntary Special Early Retirement Program (TVSERP) to provide enhanced early retirement benefits to certain eligible participants in targeted jobs that elected to retire on June 1, 2000. BGE recorded approximately $10.0 million ($7.6 million for pension 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 will amortize this regulatory asset over a 5-year period as provided by the June 2000 Maryland PSC gas base rate order. The remaining $7.0 million related to BGE's electric business was charged to expense. The TVSERP charges are not included in the tables of net periodic pension and postretirement benefit costs included in this section.

Postretirement Benefits

We sponsor defined benefit postretirement health care and life insurance plans which cover nearly all BGE employees and certain employees of our subsidiaries. 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 Pensions. 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 nonregulated businesses, we expense all 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.

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	
	2000	1999	2000	1999
	(In millions)			
Change in benefit obligation				
Benefit obligation at January 1	$1,016.7	$1,031.3	$358.7	$383.1
Service cost	25.4	26.1	7.7	8.6
Interest cost	73.1	65.3	26.6	24.4
Plan participants' contributions	--	--	2.8	2.0
Actuarial (gain) loss	0.8	(93.0)	40.9	(34.2)
Plan amendments	6.7	44.6	(41.1)	(5.0)
TVSERP charge	7.6	--	2.4	--
Benefits paid	(85.2)	(57.6)	(22.1)	(20.2)
Benefit obligation at December 31	$1,045.1	$1,016.7	$375.9	$358.7

	Pension Benefits		Postretirement Benefits	
	2000	1999	2000	1999
	(In millions)			
Change in plan assets				
Fair value of plan assets at January 1	$1,084.9	$ 985.5	$ --	$ --
Actual return on plan assets	3.7	139.4	--	--
Employer contribution	26.7	17.6	19.3	18.2
Plan participants' contributions	--	--	2.8	2.0
Benefits paid	(85.2)	(57.6)	(22.1)	(20.2)
Fair value of plan assets at December 31	$1,030.1	$1,084.9	$ --	$ --

	Pension Benefits		Postretirement Benefits	
	2000	1999	2000	1999
	(In millions)			
Funded Status				
Funded Status at				

December 31	$(15.0)	$ 68.2	$(375.9)	$(358.7)
Unrecognized net actuarial (gain) loss	49.2	(27.2)	61.4	23.6
Unrecognized prior service cost	59.2	59.0	(0.4)	(0.1)
Unrecognized transition obligation	--	--	94.8	143.4
Unamortized net asset from adoption of SFAS No. 87	(0.2)	(0.5)	--	--
Prepaid (accrued) benefit cost	$ 93.2	$ 99.5	$(220.1)	$(191.8)

Net Periodic Benefit Cost

We show the components of net periodic pension benefit cost in the following table:

Year Ended December 31,	2000	1999	1998
		(In millions)	
Components of net periodic pension benefit cost			
Service cost	$ 25.4	$ 26.1	$ 21.6
Interest cost	73.1	65.3	63.0
Expected return on plan assets	(83.6)	(76.6)	(72.1)
Amortization of transition obligation	(0.2)	(0.2)	(0.2)
Amortization of prior service cost	6.5	2.5	2.5
Recognized net actuarial loss	2.6	10.1	5.6
Amount capitalized as construction cost	(3.4)	(4.2)	(3.8)
Net periodic pension benefit cost	$ 20.4	$ 23.0	$ 16.6

We show the components of net periodic postretirement benefit cost in the following table:

Year Ended December 31,	2000	1999	1998
		(In millions)	
Components of net periodic postretirement benefit cost			
Service cost	$ 7.7	$ 8.6	$ 6.6
Interest cost	26.6	24.4	23.4
Amortization of transition obligation	7.9	11.0	11.4
Recognized net actuarial loss	3.1	1.9	0.2
Amount capitalized as construction cost	(10.8)	(9.4)	(8.1)

Net periodic postretirement benefit cost	$ 34.5	$ 36.5	$ 33.5

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Assumptions

We made the assumptions below to calculate our pension and postretirement benefit obligations.

	Pension Benefits		Postretirement Benefits	
At December 31,	2000	1999	2000	1999
Discount rate	7.50%	7.25%	7.50%	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 2000, 10.7% for Medicare-eligible retirees and 12.3% for retirees not covered by Medicare, and

. in 2001, 6.5% for Medicare-eligible retirees and 8.0% for retirees not covered by Medicare.

After 2001, we assumed both inflation rates will decrease by 0.5% annually to a rate of 5.5% in the years 2003 and 2006, respectively. After these dates, the inflation rate will remain at 5.5%.

A one-percent increase in the health care inflation rate from the assumed rates would increase the accumulated postretirement benefit obligation by approximately $51.7 million as of December 31, 2000 and would increase the combined service and interest costs of the postretirement benefit cost by approximately $5.5 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 $41.5 million as of December 31, 2000 and would decrease the combined service and interest costs of the postretirement benefit cost by approximately $4.4 million annually.

Other Postemployment Benefits

We provide the following postemployment benefits:

. health and life insurance benefits to our employees and certain employees of our subsidiaries who are found to be disabled under our Disability Insurance Plan, and

. income replacement payments for employees found to be disabled before November 1995 (payments for employees found 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 $46.7 million as of December 31, 2000 and $46.5 million as of December 31, 1999.

Effective December 31, 1993, we adopted SFAS No. 112, Employers' Accounting for Postemployment Benefits. 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 5.5% in 2000 and 1999.

Employee Savings Plan Benefits

We also sponsor a defined contribution savings plan that is offered to all eligible employees of Constellation Energy and certain employees of our subsidiaries. In a defined contribution plan, the benefits a participant is to receive result from regular contributions to a participant account. Under this plan, we make matching contributions to participant accounts. We made matching contributions to this plan of:

- $10.8 million in 2000,
- $10.4 million in 1999, and
- $10.1 million in 1998.

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 commercial paper outstanding of $198.7 million at December 31, 2000 and $242.5 million at December 31, 1999.

Constellation Energy had unused committed bank lines of credit of $565.0 million at December 31, 2000 and $295.0 million at December 31, 1999 for short-term financial needs, including letters of credit. These agreements also support Constellation Energy's commercial paper program. Letters of credit issued under these facilities totaled $180.3 million at December 31, 2000 and $23.1 million at December 31, 1999. In addition, Constellation Energy had $116.9 million in letters of credit outstanding at December 31, 2000 that were issued under separate credit facilities.

The weighted-average effective interest rate for Constellation Energy's commercial paper were 6.31% for the year ended December 31, 2000 and 5.68% for 1999.

BGE

BGE had commercial paper outstanding of $32.1 million at December 31, 2000 and $129.0 million at December 31, 1999.

At December 31, 2000, BGE had unused committed bank lines of credit totaling $218.0 million supporting the commercial paper program compared to $183.0 million at December 31, 1999.

The weighted-average effective interest rates for BGE's commercial paper were 6.36% for the year ended December 31, 2000 and 5.25% for 1999.

Other Nonregulated Businesses

Our other nonregulated businesses had short-term borrowings outstanding of $12.8 million at December 31, 2000. The weighted-average effective interest rate for our other nonregulated businesses' short-term borrowings was 8.59% for the year ended December 31, 2000.

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8 LONG-TERM DEBT

Long-term debt matures in one year or more from the date of issuance. We summarize our long-term debt in the Consolidated Statements of Capitalization. As you read this section, it may be helpful to refer to those statements.

Constellation Energy

In 2000, Constellation Energy issued $1.0 billion in long-term debt. On April 4, 2000, we issued $300.0 million of 7 7/8% Fixed Rate Notes, due April 1, 2005 and $200.0 million of Floating Rate Notes, due April 4, 2003. Interest on the floating rate notes is reset quarterly.

On June 21, 2000, we issued $300.0 million of Extendible Notes, due June 21, 2010. The interest rate on these notes resets quarterly. On June 21, 2001, the notes may be remarketed for an additional period or redeemed for a purchase price equal to 100% of their principal amount, plus accrued interest.

On October 19, 2000, we issued $200.0 million of Floating Rate Reset Notes, due March 15, 2002. We redeemed these notes on January 17, 2001 at par.

On January 17, 2001, we issued $400.0 million of Mandatorily Redeemable Floating Rate Notes, due January 17, 2002. These notes are mandatorily redeemable at a purchase price equal to 100% of their principal amount, plus accrued interest, at least five days prior to the separation of our domestic merchant energy business from our remaining businesses.

In connection with the initiative to separate our businesses, Constellation Energy expects to redeem all of its outstanding debt at or prior to the separation. The redemption will occur through a combination of open market purchases, tender offers, and redemption calls. We expect to fund this redemption with short-term debt or other credit facilities, and to refinance this debt longer term after the separation.

BGE

BGE's First Refunding Mortgage Bonds

BGE's first refunding mortgage bonds are secured by a mortgage lien on all of its assets, including all utility properties and franchises and its subsidiary capital stock. Capital stock pledged under the mortgage is that of Safe Harbor Water Power Corporation and Constellation Enterprises, Inc. The generating assets BGE transferred to subsidiaries of Constellation Energy also remain subject to the lien of BGE's mortgage.

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:

- 8 3/8% Series, due 2001
- 7 1/4% Series, due 2002
- 6 1/2% Series, due 2003
- 6 1/8% Series, due 2003
- 5 1/2% Series, due 2004
- 7 1/2% Series, due 2007
- 6 5/8% Series, due 2008

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.

BGE's Other Long-Term Debt

On July 1, 2000, BGE transferred $278.0 million of tax-exempt debt to our domestic merchant energy business related to the transferred assets. At December 31, 2000, BGE remains contingently liable for this debt.

On October 19, 2000, BGE issued $200.0 million of Floating Rate Reset Notes, due October 19, 2001. BGE can redeem these notes at 100% of the principal amount.

On December 20, 2000, BGE issued $173.0 million of 6.75% Remarketable and Redeemable Securities (ROARS) due December 15, 2012. The ROARS contain an option for the underwriters to remarket the ROARS on December 15, 2002. If the underwriters do not elect to remarket the ROARS on that date, then BGE must redeem the ROARS at 100% of the principal amount on December 15, 2002.

We show the weighted-average interest rates and maturity dates for BGE's fixed-rate medium-term notes outstanding at December 31, 2000 in the following table.

Series	Weighted-Average Interest Rate	Maturity Date
B	8.77%	2002-2006
C	7.97	2003
D	6.66	2001-2006
E	6.66	2006-2012
G	6.08	2002-2008

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 2002 and 2007

6.75%, due 2012	$25.0	June 2004 and 2007
6.73%, due 2012	$25.0	June 2004 and 2007

BGE has a $25 million revolving credit agreement that is available through 2003. At December 31, 2000 and 1999, BGE did not have any borrowings under revolving credit agreements. The bank charges us commitment fees based on the daily average of the unborrowed amount, and we pay market interest rates on any borrowings. This agreement also supports BGE's commercial paper program, as described in Note 7.

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 (net)" in the 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

Revolving Credit Agreement

ComfortLink has a $50 million unsecured revolving credit agreement that matures September 26, 2001. Under the terms of the agreement, ComfortLink has the option to obtain loans at various rates for terms up to nine months. ComfortLink pays a facility fee on the total amount of the commitment. Under this agreement, ComfortLink had outstanding $34 million at December 31, 2000 and $33 million at December 31, 1999.

Mortgage and Construction Loans

Our nonregulated businesses' mortgage and construction loans have varying terms. The following mortgage notes require monthly principal and interest payments:

- . 8.00%, due in 2001
- . 4.25%, due in 2009
- . 9.65%, due in 2028
- . 8.00%, due in 2033

The variable rate mortgage notes and construction loans require periodic payment of principal and interest.

Unsecured Notes

The unsecured notes mature on the following schedule:

	Amount
	(In millions)
7.66%, due May 5, 2001	$135.0
5.67%, due May 5, 2001	152.0
Total unsecured notes at December 31, 2000	$287.0

Maturities of Long-Term Debt

All of our long-term borrowings mature on the following schedule (includes sinking fund requirements):

Year	Constellation Energy	Nonregulated Businesses	BGE
		(In millions)	
2001	$ --	$318.9	$ 481.2
2002	200.0	15.3	319.8
2003	200.0	0.8	285.7
2004	--	8.3	155.3
2005	300.0	6.1	46.9
Thereafter	300.0	320.6	1,112.4
Total long-term debt at December 31, 2000	$1,000.0	$670.0	$2,401.3

At December 31, 2000, BGE had long-term loans totaling $221.5 million that mature after 2002 (including $110.0 million of medium-term notes discussed in this Note under "BGE's Other Long-Term Debt") that lenders could potentially require us to repay early. Of this amount, $111.5 million could be repaid in 2001, $60.0 million in 2002, and $50.0 million thereafter. At December 31, 2000, $86.5 million is classified as current portion of long-term debt as a result of these provisions.

At December 31, 2000, our nonregulated businesses had long-term loans totaling $20.0 million that mature after 2002 that lenders could potentially require us to repay early. This amount is classified as current portion of long-term debt as a result of these repayment provisions.

Weighted-Average Interest Rates for Variable Rate Debt

Our weighted-average interest rates for variable rate debt were:

Year ended December 31,	2000	1999
Nonregulated Businesses (including Constellation Energy)		
Floating rate notes	6.98%	--%
Loans under credit agreement	6.64	5.68

Mortgage and construction loans	7.78	6.65
Tax-exempt debt transferred from BGE	4.26	--
BGE		
Remarketed floating rate series mortgage bonds	6.59%	5.19%
Floating rate series mortgage bonds	--	5.41
Floating rate reset notes	7.27	--
Medium-term notes, Series G	6.58	5.38
Medium-term notes, Series H	6.58	5.64
Pollution control loan	--	3.22
Port facilities loan	--	3.24
Adjustable rate pollution control loan	--	3.59
Economic development plan	--	3.26
Variable rate pollution control plan	--	3.30

9 LEASES

There are two types of leases--operating and capital. Capital leases qualify as sales or purchases of property and are reported in the Consolidated Balance Sheets. Capital leases are not material in amount. All other leases are operating leases and are reported in the Consolidated Statements of Income. We present information about our operating leases below.

Outgoing Lease Payments

We, as lessee, lease some facilities and equipment used in our businesses. The lease agreements expire on various dates and have various renewal options. We expense all lease payments associated with our regulated utility operations.

Lease expense was:

- $11.3 million in 2000,
- $12.2 million in 1999, and
- $10.5 million in 1998.

At December 31, 2000, we owed future minimum payments for long-term, noncancelable, operating leases as follows:

Year	(In millions)
2001	$ 7.8
2002	6.4
2003	5.0
2004	3.5
2005	2.9
Thereafter	8.1
Total future minimum lease payments	$33.7

10 COMMITMENTS, GUARANTEES, AND CONTINGENCIES

Commitments

We have made substantial commitments in connection with our domestic merchant energy business construction program for future years. In addition, we have two long-term contracts for the purchase of electric generating capacity and energy. The contracts expire in 2001 and 2013. We made payments under these contracts of:

. $77.3 million in 2000,
. $67.8 million in 1999, and
. $70.7 million in 1998.

At December 31, 2000, we estimate our future payments for capacity and energy that we are obligated to buy under these contracts to be:

Year	(In millions)
2001	$ 40.2
2002	16.4
2003	16.0
2004	15.5
2005	15.1
Thereafter	113.6
Total estimated future payments for capacity and energy under long-term contracts	$216.8

Portions of these contracts became uneconomic 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 terms of the contracts as discussed in Note 4. At December 31, 2000, the accrued portion of these contracts was $21.2 million.

Our domestic merchant energy business has committed to contribute additional capital and to make additional loans to some affiliates, joint ventures, and partnerships in which they have an interest. At December 31, 2000, the total amount of investment requirements committed to by our domestic merchant energy business was $181.0 million.

BGE and BGE Home Products & Services have agreements to sell on an ongoing basis an undivided interest in a designated pool of customer receivables. Under the agreements, BGE can sell up to a total of $40 million, and BGE Home Products & Services can sell up to a total of $50 million. Under the terms of the agreements, the buyer of the receivables has limited recourse against BGE and has no recourse against BGE Home Products & Services. BGE and BGE Home Products & Services have recorded reserves for credit losses. At December 31, 2000, BGE had sold $23.9 million and BGE Home Products & Services had sold $42.5 million of receivables under these agreements.

Planned Acquisition

On December 12, 2000, we announced that a subsidiary of Constellation Nuclear will purchase 1,550 megawatts of the 1,757 megawatts total generating capacity of the Nine Mile Point nuclear power plant, located in Scriba, New York. The subsidiary of Constellation Nuclear will buy 100 percent of Unit 1 and 82 percent of Unit 2 for $815 million, including $78 million for fuel. The sale is expected to close in mid-2001 after receipt of all necessary regulatory approvals. Key regulatory approvals are required from the NRC, Federal Energy Regulatory Commission (FERC), and the New York State Public Service Commission.

One-half of the purchase price, or $407.5 million, is due at the closing of the transaction. The sellers will finance the remaining half of the purchase price at an 11.0% fixed rate for a period of five years with equal annual principal repayments. Nine Mile Point includes 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.

Niagara Mohawk Power Corporation is the sole owner of Nine Mile Point Unit 1. The co-owners of Nine Mile Point Unit 2 that are selling their interests include 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, which owns 18 percent of Nine Mile Point Unit 2, has chosen not to sell its portion at this time.

The terms of the transaction include power purchase agreements whereby we have agreed to sell 90 percent of our share of the Nine Mile Point plant's output back to the sellers for approximately 10 years at an average price of nearly $35 per megawatt-hour over the term of the power purchase agreements. The contracts for the output of both plants are based on operation of the individual units.

The sellers will transfer approximately $450 million in decommissioning funds at the time of closing. We believe this transfer is sufficient to meet the decommissioning requirements for our share of the Nine Mile Point site.

Separation Initiatives

On October 23, 2000, we announced three initiatives to advance our growth strategies. The first initiative is that we entered into an agreement (the "Agreement") with an affiliate of The Goldman Sachs Group, Inc. ("Goldman Sachs"). Under the terms of the Agreement, Goldman Sachs will acquire up to a 17.5% equity interest in our domestic merchant energy business, which will be consolidated under a single holding company ("Holdco"). Goldman Sachs will also acquire a ten-year warrant for up to 13% of Holdco's common stock (subject to certain adjustments). The warrant is exercisable six months after Holdco's common stock becomes publicly available. The amount of common stock which Goldman Sachs may receive upon exercise will be equal to the excess of the market price of Holdco's common stock at the time of exercise over the exercise price of $60 per share for all the stock subject to the warrant, divided by the market price. Holdco may at its option pay Goldman Sachs such excess in cash. Goldman Sachs is acquiring its interest and the warrant in exchange for $250 million in cash (subject to adjustment in certain instances) and certain assets related to our power marketing operation. At closing, Goldman Sachs' existing services agreement with our power marketing operation will terminate.

The second initiative is a plan to separate our domestic merchant energy business from our remaining businesses. The separation will create two stand-alone, publicly traded energy companies. One will be a merchant energy business engaged in wholesale power marketing and generation under the name "Constellation Energy Group" after the separation. The other will be a regional retail energy delivery and energy services company, BGE Corp., which will include BGE, our other nonregulated businesses, and our investment in Orion Power Holdings, Inc. ("Orion").

As a result of the separation, shareholders will continue to own all of Constellation Energy's current businesses through their ownership of the new Constellation Energy Group and BGE Corp.

The third initiative is a change in our common stock dividend policy effective April 2001. In a move closely aligned with our separation plan, effective April 2001, our annual dividend is expected to be set at $.48 per share. After the business separation, BGE Corp. expects to pay initial annual dividends of $.48 per share. Constellation Energy Group, as a growing merchant energy company, initially expects to reinvest its earnings in order to fund its growth plans and not to pay a dividend.

The closing of the transaction with Goldman Sachs and the separation are subject to customary closing conditions and contingent upon obtaining regulatory approvals and a Private Letter Ruling from the Internal Revenue Service regarding certain tax matters. The transaction and separation are expected to be completed by mid to late 2001.

Guarantees

At December 31, 2000, Constellation Energy issued guarantees in an amount up to $825.8 million related to credit facilities and contractual performance of certain of its nonregulated subsidiaries. The actual subsidiary liabilities related to these guarantees totaled $586.6 million at December 31, 2000.

At December 31, 2000, our nonregulated businesses had guaranteed outstanding loans and letters of credit of certain power projects and real estate projects totaling $50.1 million. Our nonregulated businesses also guarantee certain other borrowings of various power projects and real estate projects.

BGE guarantees two-thirds of certain debt of Safe Harbor Water Power Corporation. The maximum amount of our guarantee is $23 million. At December 31, 2000, Safe Harbor Water Power Corporation had outstanding debt of $20.0 million, of which $13.3 million is guaranteed by BGE.

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,
- chemical and waste management and disposal, and
- other environmental matters.

We discuss the significant matters below.

Clean Air

The Clean Air Act of 1990 contains two titles designed to reduce emissions of sulfur dioxide and nitrogen oxide (NOx) from electric generating stations--Title IV and Title I.

Title IV addresses emissions of sulfur dioxide. For our older plants, we meet the requirements through a combination of switching fuels and allowance trading. For newer plants, we meet the requirements primarily through facility design, and operational and pollution controls.

Title I addresses emissions of NOx. The Maryland Department of the Environment (MDE) issued regulations, effective October 18, 1999, which required up to 65% NOx emissions reductions by May 1, 2000. We entered into a settlement agreement with the MDE since we could not meet this deadline. Under the terms of the settlement agreement, we will install emissions reduction equipment at two sites by May 2002. In the meantime, we are taking steps to control NOx emissions at our generating plants.

The Environmental Protection Agency (EPA) issued a final rule in September 1998 that required up to 85% NOx emissions reduction by 22 states including Maryland and Pennsylvania. Maryland and Pennsylvania expect to meet the requirements of the rule by 2003. The emissions reduction equipment installations discussed above will allow us to meet these requirements in Maryland. The generating plants in Pennsylvania also will install emissions reduction equipment by 2003 to meet the 85% reduction requirement.

We currently estimate that the controls needed at our generating plants to meet the MDE's 65% NOx emission reduction requirements will cost approximately $150 million. Through December 31, 2000, we have spent approximately $115 million to meet the 65% reduction requirements. We estimate the additional cost for the EPA's 85% reduction requirements to be approximately $90 million by the end of 2003.

In July 1997, the EPA published new National Ambient Air Quality Standards for very fine particulates and revised standards for ozone attainment. While these standards may require increased controls at our fossil generating plants in the future, implementation, if required, would 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.

In December 2000, the EPA issued a determination that coal-fired power plant mercury emissions will be controlled. Final regulations are expected to be issued in 2004 with controls required by 2007. The costs of these controls cannot be estimated at this time since the level of control or system to implement them have not yet been established.

We received letters from the EPA requesting us to provide certain information under Section 114 of the federal Clean Air Act regarding some of our electric generating 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. In general, such standards can require the installation of additional air pollution control equipment upon the major modification of an existing plant. We have provided the EPA the requested information. We believe our generating plants have been operated in accordance with the Clean Air Act and the rules implementing the Clean Air Act. However, we cannot estimate the impact of this inquiry on our generating plants, and our financial results, at this time.

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.

We can, however, estimate that our 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 $2.3 million higher than amounts we have recorded as a liability on our Consolidated Balance Sheets. This estimate is based on a Record of Decision issued by the EPA.

Also, we are coordinating investigation of several sites where gas was manufactured in the past. The investigation of these sites includes reviewing possible actions to remove coal tar. In late December 1996, we signed a consent order with the MDE that required us to implement remedial action plans for contamination at and around the Spring Gardens site, located in Baltimore, Maryland. We submitted the required remedial action plans and they were approved by the MDE. Based on the remedial action plans, the costs we consider to be probable to remedy the contamination are estimated to total $47 million. We have recorded these costs as a liability on our Consolidated Balance Sheets and have deferred these costs, net of accumulated amortization and amounts we recovered from insurance companies, as a regulatory asset. Because of the results of studies at these sites, it is reasonably possible that these additional costs could exceed the amount we recognized by approximately $14 million. We discuss this further in Note 5. Through December 31, 2000, we have spent approximately $35 million for remediation at this site.

We do not expect the cleanup costs of the remaining 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.

Employment Discrimination

Miller 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. We believe this case is without merit. However, we cannot predict the timing, or outcome, of it or its possible effect on our, or BGE's, financial results.

Moore v. Constellation Energy Group--This action was filed on October 23, 2000 in the U.S. District Court for the District of Maryland by an employee alleging employment discrimination. Besides Constellation Energy, BGE and Constellation Holdings, Inc. are also named defendants. The Equal Employment Opportunity Commission has previously concluded that it was unable to establish a violation of law. The plaintiff seeks, among other things, unspecific monetary damages and back pay. We believe this case is without merit.

Asbestos

Since 1993, we have been involved in several actions concerning asbestos. The actions are based upon the theory of "premises liability," alleging that we 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. We described these claims in a Report on Form 8-K filed August 20, 1993. We are involved in these claims with approximately 70 other defendants. Approximately 530 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. We do not know the specific facts necessary to estimate our potential liability for these claims. The specific facts we do not know include:

. the identity of our 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, 29 of these cases were settled for amounts that were not significant.

The second type is claims by one manufacturer--Pittsburgh Corning Corp. (PCC)--against us and approximately eight others, as third-party defendants. On April 17, 2000, PCC declared bankruptcy and we do not expect PCC to prosecute this claim.

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 350 cases have been resolved, all without any payment by BGE. We do not know the specific facts necessary to estimate our potential liability for these claims. The specific facts we do not know include:

- the identity of our facilities containing asbestos manufactured by the manufacturer,
- the relationship (if any) of each of the individual plaintiffs to us,
- the settlement amounts for any individual plaintiffs who are shown to have had a relationship to us, 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 liability, if any, might be. Although insurance and hold harmless agreements from contractors who employed the plaintiffs may cover a portion of any awards in the actions, our potential liability could be material.

Restructuring Order

In early December 1999, the Mid-Atlantic Power Supply Association (MAPSA), Trigen-Baltimore Energy Corporation and Sweetheart Cup Company, Inc. filed appeals of the Restructuring Order, which were consolidated in the Baltimore City Circuit Court. MAPSA also filed a motion to delay implementation of the Restructuring Order, pending a decision on the merits of the appeals by the court.

On April 21, 2000, the Circuit Court dismissed MAPSA's appeal based on a lack of standing (the right of a party to bring a lawsuit to court) and denied its motion for a delay of the Restructuring Order. However, MAPSA filed an appeal of this decision. On May 24, 2000, the Circuit Court dismissed both the Trigen and Sweetheart Cup appeals.

MAPSA subsequently filed several appeals with the Maryland Court of Special Appeals, the Maryland Court of Appeals, and the Baltimore City Circuit Court. The effect of the appeals was to delay the implementation of customer choice in BGE's service territory.

However, on August 4, 2000, the delay was rescinded and BGE retroactively adjusted its rates as if customer choice had been implemented July 1, 2000.

On September 29, 2000, the Baltimore City Circuit Court issued an order upholding the Restructuring Order.

On October 27, 2000, MAPSA filed an appeal with the Maryland Court of Special Appeals challenging the September 29, 2000 order issued by the Circuit Court. We believe that this appeal is without merit. However, we cannot predict the timing or outcome of this case, which, if adverse, could have a material effect on our, and BGE's, financial results.

Asset Transfer Order

On July 6, 2000, MAPSA and Shell Energy LLC filed, in the Circuit Court for Baltimore City, a petition for review and a delay of the Maryland PSC's order approving the transfer of BGE's generation assets issued on June 19, 2000. The Court denied MAPSA's request for a delay on August 4, 2000, and after a hearing on the petition on August 23, 2000 issued an order on September 29, 2000 upholding the Maryland PSC's order on the asset transfer. On October 27, 2000, MAPSA filed an appeal with the Maryland Court of Special Appeals challenging the September 29, 2000 order issued by the Circuit Court. We also believe that this appeal is without merit. However, we cannot predict the timing or outcome of this case, which, if adverse, could have a material effect on our, and BGE's, financial results.

Calvert Cliffs' License Renewal

On April 11, 2000 the United States Court of Appeals for the District of Columbia Circuit, in National Whistleblowers Center v. Nuclear Regulatory Commission and Baltimore Gas and Electric Company, upheld the NRC's denial of the Center's motion to intervene in BGE's license renewal proceeding. The NRC had denied the Center's motion to intervene for failing to file timely contentions. The Center filed a petition for certiorari, a request to hear an appeal, with the U.S. Supreme Court, which was denied.

Nuclear Insurance

If there were an accident or an extended outage at either unit of the Calvert Cliffs Nuclear Power Plant (Calvert Cliffs), it could have a substantial adverse financial effect on us. The primary contingencies that would result from an incident at Calvert Cliffs could include:

- physical damage to the plant,
- recoverability of replacement power costs, and
- our liability to third parties for property damage and bodily injury.

We have insurance policies that cover these contingencies, but the policies have certain industry standard exclusions. Furthermore, the costs that could result from a covered major accident or a covered extended outage at either of the Calvert Cliffs units could exceed our insurance coverage limits.

Insurance for Calvert Cliffs and Third Party Claims

For physical damage to Calvert Cliffs, we have $2.75 billion of property insurance from an industry mutual insurance company. If an outage at either of the two units at Calvert Cliffs is caused by an insured physical damage loss and lasts more than 12 weeks, we have insurance coverage for replacement power costs up to $490.0 million per unit, provided by an industry mutual insurance company. This amount can be reduced by up to $98.0 million per unit if an outage at both units of the plant is caused by a single insured physical damage loss. If accidents at any insured plants cause a shortfall of funds at the industry mutual insurance company, all policyholders could be assessed, with our share being up to $15.4 million.

In addition we, as well as others, could be charged for a portion of any third party claims associated with a nuclear incident at any commercial nuclear power plant in the country. At December 31, 2000, the limit for third party claims from a nuclear incident is $9.54 billion under the provisions of the Price Anderson Act. If third party claims exceed $200 million (the amount of primary insurance), our share of the total liability for third party claims could be up to $176.2 million per incident. That amount would be payable at a rate of $20 million per year.

Insurance for Worker Radiation Claims

As an operator of a commercial nuclear power plant in the United States, we are required to purchase insurance to cover radiation injury claims of certain nuclear workers. On January 1, 1998, a new insurance policy became effective for all operators requiring coverage for current operations. Waiving the right to make additional claims under the old policy was a condition for acceptance under the new policy. We describe both 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 insurance policies. 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 for the next seven years. If radiation injury claims under these old policies exceed the policy reserves, all policyholders could be assessed, with our share being up to $6.3 million.

If claims under these polices exceed the coverage limits, the provisions of the Price Anderson Act (discussed in this section) would apply.

California Power Purchase Agreements

Constellation Power, Inc. and subsidiaries and Constellation Investments, Inc. (whose power projects are managed by Constellation Power) have $297.9 million invested in 14 projects that sell electricity in California under power purchase agreements called "Interim Standard Offer No. 4" agreements. Under these agreements, the projects supply electricity to utility companies at:

. a fixed rate for capacity and energy for the first 10 years of the agreements, and
. a fixed rate for capacity plus a variable rate for energy based on the utilities' avoided cost for the remaining term of the agreements.

Generally, a "capacity rate" is paid to a power plant for its availability to supply electricity, and an "energy rate" is paid for the electricity actually generated. "Avoided cost" generally is the cost of a utility's cheapest next-available source of generation to service the demands on its system.

We use the term "transitioned" to describe when the 10-year periods for fixed energy rates have expired for these power generation projects and they began supplying electricity at variable rates. In 2000, the last four projects transitioned to variable rates.

Prior to 2000, the projects that have transitioned to variable rates have had lower revenues under variable rates than they did under fixed rates. In 2000, the prices received under these agreements were higher due to the increases in the variable-rate pricing terms.

11 FAIR VALUE OF ASSETS AND LIABILITIES FROM ENERGY TRADING ACTIVITIES AND FINANCIAL INSTRUMENTS

Assets and Liabilities from Energy Trading Activities

As described in Note 1, we report assets and liabilities from energy trading activities at fair value.

At December 31, 2000, the notional amounts and terms of trading instruments at Constellation Power Source were as follows:

	Purchased	Sold	Maximum Terms in Years
	(Notional amounts in millions)		
Electric energy (megawatt-hours)	391.3	144.2	21
Electric capacity (megawatt-hours)	66.8	84.9	21
Oil (barrels)	8.5	11.9	5
Natural gas (millions of British thermal units)	373.5	316.3	9

Notional amounts express the contractual volume of transactions but do not necessarily represent the amounts to be exchanged by the parties to the instruments. Accordingly, notional amounts do not accurately measure our exposure to market or credit risk.

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 used the following methods and assumptions in 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: The amounts reported in the 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.
- 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 section.

At December 31,	2000		1999	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In millions)			

Investments and other assets for which it is:				
Practicable to estimate fair value	$349.8	$ 349.8	$ 313.3	$ 313.3
Not practicable to estimate fair value	43.5	N/A	46.7	N/A
Fixed-rate long-term debt	2,734.1	2,819.9	2,728.9	2,637.3
Variable-rate long-term debt	1,331.8	1,243.3	654.8	654.8

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, and
- several partnerships that own solar powered energy production facilities.

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 $32.7 million at December 31, 2000 and $35.8 million at December 31, 1999, representing ownership interests up to 11%. The total assets of all of these partnerships totaled $6.1 billion at December 31, 1999 (which is the latest information available).

The investments in solar powered energy production facility partnerships totaled $10.8 million at December 31, 2000 and $10.9 million at December 31, 1999, representing ownership interests up to 13%. The total assets of all of these partnerships totaled $26.7 million at December 31, 1999 (which is the latest information available).

Guarantees

It was not practicable to determine the fair value of certain loan guarantees of Constellation Energy and its subsidiaries. Constellation Energy guaranteed outstanding debt of $341.0 million at December 31, 2000 and $16.5 million at December 31, 1999. Our nonregulated businesses guaranteed outstanding debt totaling $50.1 million at December 31, 2000 and $48.8 million at December 31, 1999. BGE guaranteed outstanding debt of $13.3 million at December 31, 2000 and $13.6 million at December 31, 1999. We do not anticipate that we will need to fund these guarantees.

12 STOCK-BASED COMPENSATION

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.

Under our existing long-term incentive plans, we can issue awards that include stock options and performance-based restricted stock to officers and key employees. Under the plans, we can issue up to a total of 6,000,000 shares for these awards.

Stock Options

In May 2000, our Board of Directors approved the issuance of non-qualified stock options. The options were granted at prices not less than the market value of the stock at the date of grant, generally become exercisable ratably over a three-year period beginning one-year from the date of grant, and expire ten years from the date of grant. The grants provide for the exercise of the options on a pro-rata basis for service to date upon the separation of our businesses. The tables below do not reflect the impact of the business separation. In accordance with APB No. 25, no compensation expense is recognized for the stock option awards. Summarized information for our stock option awards is as follows:

	Shares	Weighted-Average Exercise Price
(In thousands, except per share amounts)		
Outstanding at January 1, 2000	--	$ --
Granted	2,462	34.64
Exercised	--	--
Cancelled/Expired	(42)	(34.25)
Outstanding at December 31, 2000	2,420	$ 34.65
Exercisable at December 31, 2000	--	--
Weighted-average fair value per share of options granted during year		$ 5.60

A summary of the weighted-average remaining contractual life and the weighted-average exercise price of options outstanding as of December 31, 2000 is presented below:

Range of Exercise Prices	Options Outstanding at December 31, 2000 (In thousands)	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Life (In years)
$34.25-$40.72	2,420	$34.65	9.4

Performance-Based Restricted Stock Awards

In addition, we issue common stock based on meeting certain performance and service goals that vests to participants at various times ranging from three to five years. In accordance with APB No. 25, we recognize compensation expense for our restricted stock awards. Compensation expense recorded was $16.3 million for 2000 and $10.5 million for 1999. Prior to 1999, compensation expense was not material. Summarized share information for our restricted stock awards is as follows:

(In thousands, except per share amounts)	2000	1999
Outstanding, beginning of year	323	350
Granted	353	358
Released to participants	(277)	(362)
Cancelled	(22)	(23)
Outstanding, end of year	377	323
Weighted-average fair value per share of restricted stock granted during the year	$32.89	$28.61

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:

	2000
Risk-free interest rate	6.37%
Expected life (in years)	10.0
Expected market price volatility factors	21.0%
Expected dividend yields	5.7%

The effect of applying SFAS No. 123 to our stock-based awards results in net income and earnings per share that are not materially different from amounts reported.

13 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.

2000 Quarterly Data--Constellation Energy

	Revenue	Income from Operations	Earnings Applicable to Common Stock	Earnings Per Share of Common Stock

	(In millions, except per-share amounts)			
Quarter Ended				
March 31	$ 992.2	$182.8	$ 72.1	$0.48
June 30	868.4	133.9	39.6	0.26
September 30	981.6	315.4	147.5	0.98
December 31	1,036.3	208.1	86.1	0.57
Year Ended				
December 31	$3,878.5	$840.2	$345.3	$2.30

2000 Quarterly Data--BGE

	Revenue	Income from Operations	Earnings Applicable to Common Stock
	(In millions, except per-share amounts)		
Quarter Ended			
March 31	$ 720.7	$133.9	$ 50.9
June 30	659.4	126.7	49.1
September 30	690.0	65.0	10.0
December 31	676.7	84.5	20.3
Year Ended			
December 31	$2,746.8	$410.1	$130.3

First quarter results include:

Constellation Energy and BGE

- a $2.5 million after-tax expense for BGE Employees that elected to participate in a Targeted Voluntary Special Early Retirement Program (TVSERP)(see Note 2),
- $37.5 million in amortization expense for the reduction of our generation plants associated with the Restructuring Order (see the "Electric Depreciation and Amortization Expense" section of Management's Discussion and Analysis),

Second quarter results include:

Constellation Energy and BGE

- a $1.7 million after-tax expense for the TVSERP (see Note 2),
- $37.5 million in amortization expense for the reduction of our generation plants associated with the Restructuring Order, and

Constellation Energy

- a $15.0 million after-tax deregulation transition cost to a third party incurred by our power marketing operation to provide BGE's standard offer service requirements (see Note 2).

1999 Quarterly Data--Constellation Energy

	Revenue	Income from Operations	Earnings Applicable to Common Stock	Earnings Per Share of Common Stock
	(In millions, except per-share amounts)			
Quarter Ended				
March 31	$ 983.4	$198.1	$ 82.8	$ 0.55
June 30	858.5	163.9	68.0	0.45
September 30	1,010.2	277.7	136.1	0.91
December 31	934.1	120.2	(26.8)	(0.18)
Year Ended				
December 31	$3,786.2	$759.9	$260.1	$1.74

1999 Quarterly Data--BGE

	Revenue	Income from Operations	Earnings Applicable to Common Stock
	(In millions, except per-share amounts)		
Quarter Ended			
March 31	$ 983.4	$198.1	$ 82.8
June 30	682.0	140.9	57.8
September 30	756.0	283.3	151.5
December 31	670.8	82.0	(43.5)
Year Ended			
December 31	$3,092.2	$704.3	$248.6

Constellation Energy's second quarter results include a $3.6 million after-tax write-down of a financial investment (see Note 3).

Third quarter results include:

Constellation Energy and BGE

- $7.5 million associated with Hurricane Floyd (see the "Electric Operations and Maintenance Expenses" section of Management's Discussion and Analysis),
- a $37.5 million deferral of revenues collected associated with the deregulation of our electric generation business (see Note 5),

Constellation Energy

- a $17.3 million after-tax write-down of a financial investment (see Note 3),
- a $6.7 million after-tax write-off of a power project (see Note 3), and
- a $3.4 million after-tax write-down of certain senior-living facilities (see Note 2).

Fourth quarter results include:

Constellation Energy and BGE

- a $66.3 million extraordinary charge associated with the Restructuring Order (see Note 4),
- the recognition of the $37.5 million of revenues that were deferred in the third quarter (see above),
- $75 million in amortization expense for the reduction of our generation plants associated with the Restructuring Order,

Constellation Energy

- a $4.9 million after-tax gain on a financial investment (see Note 3),
- $12.0 million after-tax write-downs of certain power projects (see Note 3), and
- a $2.4 million after-tax write-down of certain senior-living facilities (see 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.

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14 RELATED PARTY TRANSACTIONS--BGE

Income Statement

Under the Restructuring Order, 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. Constellation Power Source 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. The cost of BGE's purchased energy from nonregulated affiliates of Constellation Energy to meet its standard offer service obligation was $581.0 million for the year ended December 31, 2000.

In addition, BGE receives charges from Constellation Energy for 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 $21.6 million for the year ended December 31, 2000. These costs were not material in 1999 due to the creation of Constellation Energy effective April 30, 1999 and the subsequent transfer of certain BGE employees to the holding company later that year.

Balance Sheet

As a result of the deregulation of electric generation, BGE transferred its generation assets to nonregulated affiliates of Constellation Energy effective July 1, 2000. In conjunction with this transfer, Constellation Power Source Generation, Inc. issued approximately $366 million in unsecured promissory notes to BGE. Repayments of the notes by Constellation Power Source Generation, Inc. will be used exclusively to service current maturities of certain BGE long-term debt. As of December 31, 2000, $87 million of these notes are still outstanding and will mature on March 14, 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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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 on pages 4 through 6 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 on pages 7 and 8 under Directors' Compensation, on page 8 under Compensation Committee Interlocks and Insider Participation, on pages 11 through 14 under Executive Compensation, on page 15 under Common Stock Performance Graph and on pages 15 through 18 under 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

The information required by this item regarding security ownership of certain beneficial owners and management is set forth on pages 9 and 10 under Security Ownership in the Proxy Statement and is incorporated herein by reference.

Item 13. Certain Relationships and Related Transactions

The information required by this item is set forth on page 8 under Certain Relationships and Transactions and Compensation Committee Interlocks and Insider Participation in the Proxy Statement and is incorporated herein by reference.

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PART IV

Item 14. 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 17, 2001 of

PricewaterhouseCoopers LLP
Consolidated Statements of Income--Constellation Energy Group for three years ended December 31, 2000
Consolidated Statements of Comprehensive Income--Constellation Energy Group for three years ended December 31, 2000
Consolidated Balance Sheets--Constellation Energy Group at December 31, 2000 and December 31, 1999
Consolidated Statements of Cash Flows--Constellation Energy Group for three years ended December 31, 2000
Consolidated Statements of Common Shareholders' Equity--Constellation Energy Group for three years ended December 31, 2000
Consolidated Statements of Capitalization--Constellation Energy Group at December 31, 2000 and December 31, 1999
Consolidated Statements of Income Taxes--Constellation Energy Group for three years ended December 31, 2000
Consolidated Statements of Income--Baltimore Gas and Electric Company for three years ended December 31, 2000
Consolidated Statements of Comprehensive Income--Baltimore Gas and Electric Company for three years ended December 31, 2000
Consolidated Balance Sheets--Baltimore Gas and Electric Company at December 31, 2000 and December 31, 1999
Consolidated Statements of Cash Flows--Baltimore Gas and Electric Company for three years ended December 31, 2000
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) -- Bylaws of Constellation Energy Group, Inc., as amended to February 16, 2001. (Designated as Exhibit No. 3(d) in Form S-3 dated March 5, 2001, File No. 333-56572.)

*3(f) -- 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) -- 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:

	Designated In		
Dated	File No.		Exhibit Number
*July 15, 1977 (3 Indentures)	2-59772		2-3
*August 15, 1991	33-45259	(Form S-3 Registration)	4(a)(i)
*January 15, 1992	33-45259	(Form S-3 Registration)	4(a)(ii)
*July 1, 1992	1-1910	(Form 8-K Report for January 29, 1993)	4(a)
*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(c) -- 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(d) -- 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(e) -- 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(f) -- Form of Preferred Securities Guarantee (Designated as Exhibit 4(f) in Form S-3 dated May 28, 1998, File No. 333-53767).

*4(g) -- Form of Junior Subordinated Debenture (Designated as Exhibit 4(h) in Form S-3 dated May 28, 1998, File No. 333-53767).

*4(h) -- 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).

*4(i) -- Specimen Note for $173,000,000 6.75% Remarketable or Redeemable Securities (ROARSSM) due 2012 (Designated as Exhibit 4(f) in Form 8-K dated December 20, 2000, File No. 1-1910.)

*10(a) -- Executive Annual Incentive Plan of Constellation Energy Group, Inc., as amended and restated. (Designated as Exhibit No. 10(b) to the Annual Report on Form 10-K for the year ended December 31, 1999, File Nos. 1-12869 and 1-19101.)

10(b) -- Constellation Energy Group, Inc. 1995 Long-Term Incentive Plan, as amended and restated.

*10(c) -- Constellation Energy Group, Inc. Nonqualified Deferred Compensation Plan, as amended and restated. (Designated as Exhibit No. 10(b) in Form 10-Q dated November 12, 1999, File Nos. 1-12869 and 1-19101.)

*10(d) -- Constellation Energy Group, Inc. Deferred Compensation Plan for Non-Employee Directors. (Designated as Exhibit No. 10(a) in Form 10-Q dated May 14, 1999, File Nos. 1-12869 and 1-19101.)

*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 1-19101.)

*10(f) -- Summary of severance arrangement for a named executive officer. (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.

*10(h) -- Form of Severance Agreements between Baltimore Gas and Electric Company and seven key employees. (Designated as Exhibit No. 10(j) in Form 10-Q dated May 14, 1999, File Nos. 1-12869 and 1-19101.)

*10(i) -- Summary of enhanced retirement benefits for a named executive officer. (Designated as Exhibit No. 10(l) in Form 10-Q dated May 14, 1999, File Nos. 1-12869 and 1-19101.)

*10(j) -- 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 1-19101.)

*10(k) -- Constellation Energy Group, Inc. Long-Term Incentive Plan. (Designated as Exhibit No. 10(b) in Form 10-Q dated May 14, 1999, File Nos. 1-12869 and 1-19101.)

*10(l) -- 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.)

*10(m) -- Constellation Energy Group, Inc. Benefits Restoration Plan. (Designated as Exhibit No. 10(b) in Form 10-Q dated August 14, 2000, File Nos. 1-12869 and 1-1910.)

10(n) -- Constellation Energy Group, Inc. Supplemental Pension Plan.

10(o) -- Constellation Energy Group, Inc. Senior Executive Supplemental Plan.

*10(p) -- Constellation Energy Group, Inc. Supplemental Benefits Plan. (Designated as Exhibit No. 10(e) in Form 10-Q dated August 14, 2000, File Nos. 1-12869 and 1-1910.)

12(a) -- Constellation Energy Group, Inc. and Subsidiaries Computation of Ratio of Earnings to Fixed Charges.

12(b) -- Baltimore Gas and Electric Company and Subsidiaries Computation of Ratio of Earnings to Fixed Charges and Computation of Ratio of Earnings to Combined Fixed Charges and Preferred and Preference Dividend Requirements.

21 -- Subsidiaries of the Registrant.

23 -- Consent of PricewaterhouseCoopers LLP, Independent Accountants.

* Incorporated by Reference.

(b) Reports on Form 8-K:

Date Filed	Item Reported
Constellation Energy and BGE	
October 23, 2000	Item 5. Other Events Item 7. Financial Statements and Exhibits
December 12, 2000	Item 5. Other Events Item 7. Financial Statements and Exhibits
BGE	

December 20, 2000 Item 5. Other Events

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CONSTELLATION ENERGY GROUP, INC. AND SUBSIDIARIES
AND
BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARIES

SCHEDULE II -- VALUATION AND QUALIFYING ACCOUNTS

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at beginning of period	Charged to costs and expenses	Charged to other accounts-- describe	(Deductions)-- describe	Balance at end of period
			(in millions)		
Reserves deducted in the Balance Sheet from the assets to which they apply:					
Constellation Energy					
Accumulated Provision for Uncollectibles					
2000..................	$ 34.8	$21.1	$ --	$(34.6)(A)	$ 21.3
1999..................	35.4	21.5	--	(22.1)(A)	34.8
1998..................	24.1	28.0	--	(16.7)(A)	35.4
Valuation Allowance --					
Net unrealized (gain) loss on available for sale securities					
2000..................	0.2	--	(33.9)(B)	--	(33.7)
1999..................	(9.4)	--	9.6 (B)	--	0.2
1998..................	(7.6)	--	(1.8)(B)	--	(9.4)
Net unrealized (gain) loss on nuclear decommissioning trust fund					
2000..................	(40.5)	--	5.8 (C)	--	(34.7)
1999..................	(23.9)	--	(16.6)(C)	--	(40.5)
1998..................	(10.0)	--	(13.9)(C)	--	(23.9)
Assets from trading activities reserves					
2000..................	(27.5)	--	(26.9)(D)	--	(54.4)
1999..................	(0.6)	--	(26.9)(D)	--	(27.5)
1998..................	--	--	(0.6)(D)	--	(0.6)
BGE					
Accumulated Provision for Uncollectibles					
2000..................	13.0	16.4	--	(16.0)(A)	13.4
1999..................	35.4	17.6	--	(40.0)(E)	13.0
1998..................	24.1	28.0	--	(16.7)(A)	35.4
Valuation Allowance --					
Net unrealized (gain)					

loss on available for sale securities					
2000..................	--	--	--	--	--
1999..................	(9.4)	--	(5.3)(B)	14.7 (F)	--
1998..................	(7.6)	--	(1.8)(B)	--	(9.4)
Net unrealized (gain) loss on nuclear decommissioning trust fund					
2000..................	(40.5)	--	(1.8)(C)	42.3 (G)	--
1999..................	(23.9)	--	(16.6)(C)	--	(40.5)
1998..................	(10.0)	--	(13.9)(C)	--	(23.9)

(A) Represents principally net amounts charged off as uncollectible.
(B) Represents net unrealized (gains)/losses (credited)/charged to accumulated other comprehensive income.
(C) Represents net unrealized (gains)/losses (credited)/charged to accumulated depreciation.
(D) Represents a reserve from assets for energy trading activities charged to revenues.
(E) Represents approximately $17 million charged off as uncollectible and approximately $23 million transferred from BGE to Constellation Energy as a result of the formation of the holding company.
(F) Represents amount transferred from BGE to Constellation Energy as a result of the formation of the holding company.
(G) Represents balance transferred to a subsidiary of Constellation Nuclear, LLC on July 1, 2000.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, Constellation Energy Group, Inc., the Registrant, has duly caused this Report to be signed on its behalf by the undersigned, thereunto duly authorized.

CONSTELLATION ENERGY GROUP, INC.
(Registrant)

Date: March 30, 2001 By /s/ C. H. Poindexter

C. H. Poindexter
Chairman of the Board, President, and
Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this Report has been signed below by the following persons on behalf of Constellation Energy Group, Inc., the Registrant, and in the capacities and on the dates indicated.

Signature	Title	Date
Principal executive officer and director:		
By /s/ C. H. Poindexter	Chairman of the Board, President, Chief	March 30, 2001

C. H. Poindexter	Executive Officer, and Director	

Principal financial and accounting officer:

By /s/ D. A. Brune D. A. Brune	Vice President, Chief Financial Officer and Secretary	March 30, 2001

Directors:

/s/ H. F. Baldwin H. F. Baldwin	Director	March 30, 2001
/s/ D. L. Becker D. L. Becker	Director	March 30, 2001
/s/ J. T. Brady J. T. Brady	Director	March 30, 2001
/s/ B. B. Byron B. B. Byron	Director	March 30, 2001
/s/ J. O. Cole J. O. Cole	Director	March 30, 2001
/s/ D. A. Colussy D. A. Colussy	Director	March 30, 2001
/s/ E. A. Crooke E. A. Crooke	Director	March 30, 2001
/s/ J. R. Curtis J. R. Curtiss	Director	March 30, 2001
/s/ R. W. Gale R. W. Gale	Director	March 30, 2001
/s/ J. W. Geckle J. W. Geckle	Director	March 30, 2001

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Signature	Title	Date
/s/ F. A. Hrabowski III F. A. Hrabowski III	Director	March 30, 2001
/s/ R. J. Hurst R. J. Hurst	Director	March 30, 2001
/s/ N. Lampton N. Lampton	Director	March 30, 2001
/s/ C. R. Larson C. R. Larson	Director	March 30, 2001
/s/ G. L. Russell, Jr. G. L. Russell, Jr.	Director	March 30, 2001
/s/ M. A. Shattuck, III M. A. Shattuck, III	Director	March 30, 2001
/s/ M. D. Sullivan M. D. Sullivan	Director	March 30, 2001

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Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, Baltimore Gas and Electric Company, the Registrant, has duly caused this Report to be signed on its behalf by the undersigned, thereunto duly authorized.

BALTIMORE GAS AND ELECTRIC COMPANY
(Registrant)

Date: March 30, 2001

By /s/ F. O. Heintz

F. 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 30, 2001
Principal financial and accounting officer and director:		
By /s/ D. A. Brune D. A. Brune	Vice President, Chief Financial Officer, Secretary, and Director	March 30, 2001
Directors:		
/s/ C. H. Poindexter C. H. Poindexter	Director	March 30, 2001
/s/ R. E. Denton R. E. Denton	Director	March 30, 2001
/s/ T. F. Brady T. F. Brady	Director	March 30, 2001
/s/ E. A. Crooke E. A. Crooke	Director	March 30, 2001

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) -- Bylaws of Constellation Energy Group, Inc., as amended to February 16, 2001. (Designated as Exhibit No. 3(d) in Form S-3 dated March 5, 2001, File No. 333-56572.)

*3(f) -- 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) -- 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:

	Designated In		
Dated	File No.		Exhibit Number
*July 15, 1977 (3 Indentures)	2-59772		2-3
*August 15, 1991	33-45259	(Form S-3 Registration)	4(a)(i)
*January 15, 1992	33-45259	(Form S-3 Registration)	4(a)(ii)
*July 1, 1992	1-1910	(Form 8-K Report for January 29, 1993)	4(a)

*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(c) -- 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).)

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*4(d) -- 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(e) -- 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(f) -- Form of Preferred Securities Guarantee (Designated as Exhibit 4(f) in Form S-3 dated May 28, 1998, File No. 333-53767).

*4(g) -- Form of Junior Subordinated Debenture (Designated as Exhibit 4(h) in Form S-3 dated May 28, 1998, File No. 333-53767).

*4(h) -- 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).

*4(i) -- Specimen Note for $173,000,000 6.75% Remarketable or Redeemable Securities (ROARSSM) due 2012 (Designated as Exhibit 4(f) in Form 8-K dated December 20, 2000, File No. 1-1910.)

*10(a) -- Executive Annual Incentive Plan of Constellation Energy Group, Inc., as amended and restated. (Designated as Exhibit No. 10(b) to the Annual Report on Form 10-K for the year ended December 31, 1999, File Nos. 1-12869 and 1-19101.)

10(b) -- Constellation Energy Group, Inc. 1995 Long-Term Incentive Plan, as amended and restated.

*10(c) -- Constellation Energy Group, Inc. Nonqualified Deferred Compensation Plan, as amended and restated. (Designated as Exhibit No. 10(b) in Form 10-Q dated November 12, 1999, File Nos. 1-12869 and 1-19101.)

*10(d) -- Constellation Energy Group, Inc. Deferred Compensation Plan for Non-Employee Directors. (Designated as Exhibit No. 10(a) in Form 10-Q dated May 14, 1999, File Nos. 1-12869 and 1-19101.)

*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 1-19101.)

*10(f) -- Summary of severance arrangement for a named executive officer. (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.

*10(h) -- Form of Severance Agreements between Baltimore Gas and Electric Company and seven key employees. (Designated as Exhibit No. 10(j) in Form 10-Q dated May 14, 1999, File Nos. 1-12869 and 1-19101.)

*10(i) -- Summary of enhanced retirement benefits for a named executive officer. (Designated as Exhibit No. 10(l) in Form 10-Q dated May 14, 1999, File Nos. 1-12869 and 1-19101.)

*10(j) -- 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 1-19101.)

*10(k) -- Constellation Energy Group, Inc. Long-Term Incentive Plan. (Designated as Exhibit No. 10(b) in Form 10-Q dated May 14, 1999, File Nos. 1-12869 and 1-19101.)

*10(l) -- 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.)

*10(m) -- Constellation Energy Group, Inc. Benefits Restoration Plan. (Designated as Exhibit No. 10(b) in Form 10-Q dated August 14, 2000, File Nos. 1-12869 and 1-1910.)

10(n) -- Constellation Energy Group, Inc. Supplemental Pension Plan.

10(o) -- Constellation Energy Group, Inc. Senior Executive Supplemental Plan.

*10(p) -- Constellation Energy Group, Inc. Supplemental Benefits Plan. (Designated as Exhibit No. 10(e) in Form 10-Q dated August 14, 2000, File Nos. 1-12869 and 1-1910.)

12(a) -- Constellation Energy Group, Inc. and Subsidiaries Computation of Ratio of Earnings to Fixed Charges.

12(b) -- Baltimore Gas and Electric Company and Subsidiaries Computation of Ratio of Earnings to Fixed Charges and Computation of Ratio of

Earnings to Combined Fixed Charges and Preferred and Preference Dividend Requirements.

21 -- Subsidiaries of the Registrant.

23 -- Consent of PricewaterhouseCoopers LLP, Independent Accountants.

* Incorporated by Reference.