Constellation Energy Group

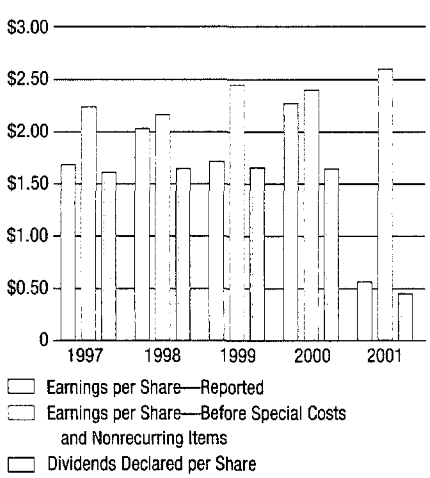
strength +

2001 ANNUAL REPORT

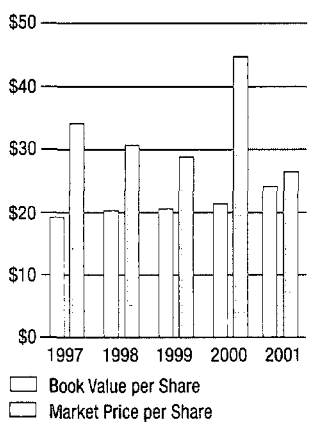
	2001	2000	% Change
	(In millions, except per share amounts)		
Common Stock Data			
Earnings per share			
Earnings per share before special costs included in operations and cumulative effect of change in accounting principle	$ 2.60	$ 2.43	7.0%
Earnings per share before cumulative effect of change in accounting principle	0.52	2.30	(77.4)%
Earnings per share	0.57	2.30	(75.2)%
Dividends declared per share	$ 0.48	$ 1.68	(71.4)%
Average shares outstanding	160.7	150.0	7.1%
Return on average common equity			
Excluding special costs and nonrecurring items	10.9%	11.9%	(8.4)%
Reported	2.5%	11.3%	(77.9)%
Book value per share—year end	$ 23.48	$ 21.09	11.3%
Market price per share—year end	$ 26.55	$ 45.06	(41.1)%
Market value of common stock—year end	$ 4,346	$ 6,783	(35.9)%
Financial Data			
Total revenues	$ 3,928	$ 3,853	1.9%
Income from operations	$ 358	$ 843	(57.5)%
Income before cumulative effect of change in accounting principle	$ 82	$ 345	(76.2)%
Cumulative effect of change in accounting principle	9	–	
Net income	$ 91	$ 345	(73.6)%
Assets			
Merchant energy business	$ 8,134	$ 7,296	11.5%
Regulated utility business	4,869	4,482	8.6%
Other businesses and corporate items	1,075	1,161	(7.4)%
Total assets	$14,078	$12,939	8.8%
Total common equity	$ 3,844	$ 3,174	21.1%
Nonregulated capital expenditures	$ 1,850	$ 830	122.9%
Regulated capital expenditures	$ 239	$ 350	(31.7)%

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

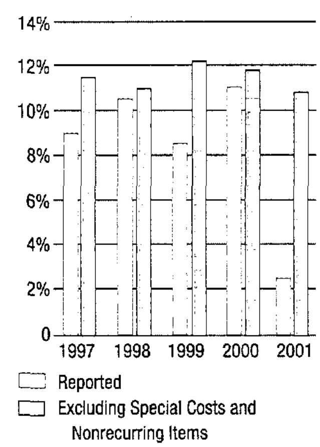
Earnings and Dividends Declared* Per Share of Common Stock



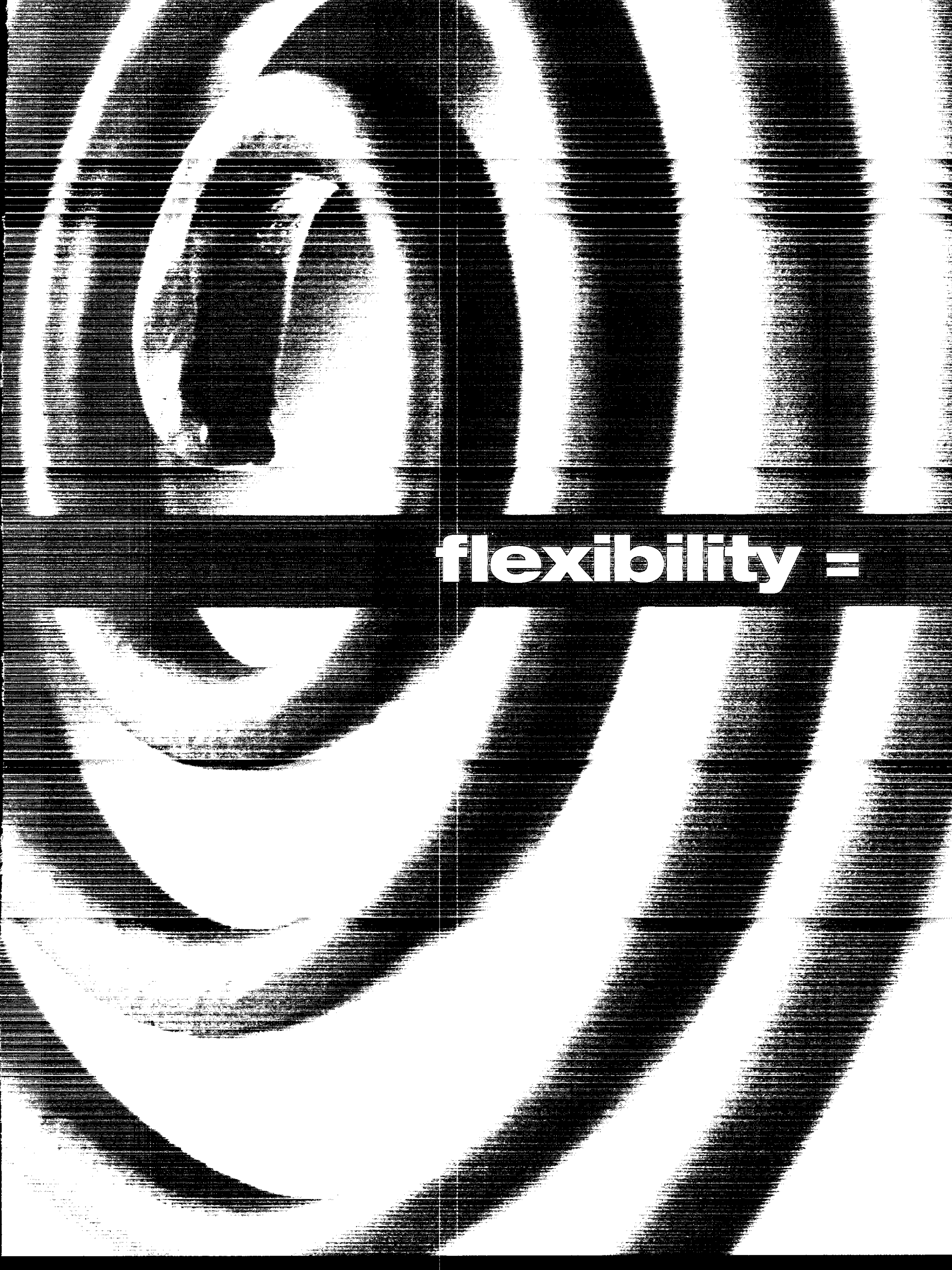
Common Stock Market Price and Book Value Per Share



Return on Average Common Equity



** In January 2002, the Board of Directors announced it will increase the dividend to 96 cents per share (24 cents quarterly).*


flexibility =

With a long history in Central Maryland, Constellation Energy Group has repeatedly demonstrated the strength and flexibility to prosper in diverse market conditions.

Our *strength* is rooted in industry knowledge, experience, and in valuable assets that include a premier gas and electric utility and a diverse portfolio of power plants.

Our *flexibility* comes from a strong balance sheet, proven commercial skills, and strong decision-making abilities that allow us to adjust rapidly to evolving market conditions. This agility propels us forward as we act quickly to capitalize on the opportunities of the marketplace.

Together, strength and flexibility are the formula for our success.

But strength and flexibility have another advantage: they are the perfect platform for growth. As our industry continues to change, we have the generation assets and the marketing expertise to capitalize. As the economy gains forward momentum, we are perfectly positioned to build upon the solid foundation that is our company.

Such is the success of Constellation Energy Group.


formula for success.

No doubt, 2001 was a tough year for our company, as it was for the entire energy industry. The combination of many factors, including the dramatic decline in power prices, the collapse of Enron, and the dynamics of the California market, led us to make similarly dramatic changes in our strategy and our organization. In 2001, we canceled our plans to separate, terminated our relationship with Goldman Sachs, and brought on a new CEO. We also moved to control costs, streamline our organization, and intensify our focus on risk management. As the year ended, we were already seeing the positive results of our decisive actions, and we are pleased to convey our confidence that we have emerged from a difficult year stronger than ever.

Ours has been an industry in transition for nearly a decade. Much of the upheaval experienced in the past year may be an inevitable and necessary step in the evolution from a regulated to a competitive market. This transformation has caused volatility and uncertainty around many factors that affect our company's profitability. While we wholeheartedly endorse the industry's migration to a freely competitive market, we are focused on maintaining our strength and flexibility, both strategically and financially, and managing risk vigilantly while positioning our company for the future. Thus, that is the theme of this annual report.

Financial Highlights

Our 2001 earnings from operations were $2.60 per share compared to $2.43 per share in 2000. In the fourth quarter, however, we reported a series of special costs that together equal approximately $533 million, or a total earnings per share impact of $2.08. We also recorded a cumulative effect of an accounting principle change in the first quarter that increased earnings per share by $.05. This resulted in reported earnings for the calendar year of $.57 per share.

The special costs recognized in the fourth quarter (see pages 22–23 in the Financial section) are the result of rigorous analysis coupled with an aggressive strategy to monetize our non-core assets, improve our balance sheet, and rationalize our cost structure. With these actions, we want to assure you that we are clearly focused on our core business of energy.

Dividend Policy Changes

Going forward, we are committed and determined to improve our results. Achieving a competitive *total* return on your investment is our goal. Since deciding not to separate into two companies, we recognized that we needed to change our dividend policy that became effective last year in April.

On January 30, we announced that we would increase our annual dividend from $.48 to $.96 per share beginning with

Christian H. Poindexter, Chairman of the Board and Mayo A. Shattuck III, President and Chief Executive Officer.

the next quarterly payment date of April 1, 2002. The dividend is a meaningful contributor to our goal of providing superior return to our shareholders.

Focus on the Fundamentals

One of the most important strategic decisions we made last year was deciding not to separate our merchant from our retail energy services business. This significant choice was partly driven by the capital markets, which had shifted dramatically and no longer awarded a cost-of-capital advantage to merchant generation companies. We also recognized that in times of economic uncertainty, it's wise to build from a base of scale and stability and that there is strength in a portfolio of businesses that balances earnings growth and cash flow.

The collapse of Enron and the steady decline in the value of all merchant energy companies have demonstrated that our courageous decision not to separate was, in fact, the right decision.

Since canceling separation, we have moved quickly to realign the management team and streamline our organization. We have established three operating units and put the right people with the right skills in charge to manage them.

In addition, we have created a new staff role of Chief Risk Officer, who is focused on defining and managing all key risks across the company. It was particularly gratifying that our prudent business practices allowed us to avoid any material Enron-related losses. This new position strengthens our ability to continue to manage risk responsibly.

The strategic and organizational decisions of 2001 provide real clarity to our direction. We are focused on being a leader in the wholesale merchant energy business and providing premier utility and energy-related services in Maryland and the surrounding region.

In pursuing these strategies, we are guided by the core values that are fundamental to the successful operation of Constellation Energy Group. This is a company that has a

186-year history of dealing fairly with its customers, of maintaining the highest level of integrity, and of living up to its responsibility to its shareholders, communities, and employees.

A Solid Platform for Growth

A Strong Base of Generation Assets

We believe that the strongest energy businesses have physical assets to complement their merchant capabilities. Our strength in generation, including our expanding influence in the nuclear world, is a true core competency. In 2001, we started the year by winning the Edison Award, our industry's most prestigious honor, for our pioneering work in nuclear license renewal. We ended the year with the purchase of Nine Mile Point Nuclear Station. In the summer, we brought on line 1,100 megawatts of new gas-fired generation. We also have under construction an additional 2,900 megawatts in key parts of the country.

As of year-end 2001, our Generation Group owned and operated about 9,200 megawatts of power. With 2,900 megawatts under construction, it will have more than 12,000 megawatts by the end of 2003 when all the plants will be completed.

Leveraging Our Assets

Our power marketing, long-term power contract origination, and risk management business leverages off of the strength of our generation assets and is a vital part of our company's success. Since its inception five years ago, this operation has generated strong earnings growth for Constellation. Much of this growth has been driven by serving electric distribution companies that have elected to outsource their wholesale supply. Constellation is now a key player in the Northeast, the Mid-Atlantic, and Texas—three regions that have meaningfully deregulated their retail energy markets. We plan to continue to grow our load-serving market positions in these regions.

We built the risk management and long-term power contract origination business with the help of our advisor, Goldman Sachs. One of the strategic decisions made in 2001 was the termination of the power business services agreement with Goldman. This allows us to benefit from 100% of the profits and provides us with strategic and operating control of this business, which is critically linked to our fleet of generation assets.

Reliable Delivery and Returns

Our regulated utility, Baltimore Gas and Electric Company (BGE), balances our portfolio of energy businesses. BGE holds a solid franchise in an economically healthy region that has successfully deregulated the electric and gas supply. As an energy-delivery company, BGE provides very predictable earnings and generates high cash flow with a low risk profile.

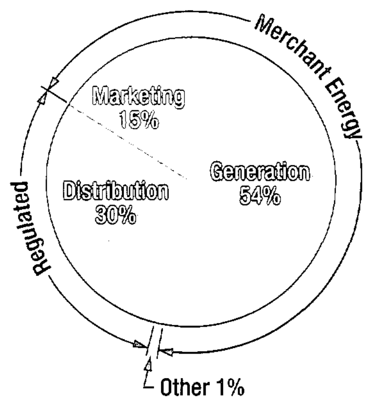
BGE's 186-year heritage of serving Central Maryland is unique in our industry. Today, BGE delivers energy to more than 1.1 million electric and 600,000 gas customers. As always, its primary focus is on reliability, safety, and achieving operational excellence.

Toward that end, the utility embraced a new initiative in 2001 to comprehensively review and re-engineer key business processes. Now implementing the more than 200 recommen-

This is a long-term business, and Constellation Energy Group has proven that the same strength and flexibility that have sustained this company for more than 186 years will help us withstand virtually any challenge the future may bring.

Maintaining the Balance

2002 Sources of Net Income



Constellation Energy Group owns a balanced portfolio of businesses—regulated and nonregulated—that should provide dependable earnings growth and strong cash flow with a moderate level of risk.

dations that came out of the process, BGE has created the blueprint for substantially improving business processes, functions, and activities while providing customers with more efficient, effective, and hassle-free service.

A Company With Staying Power

The California situation combined with Enron's collapse and a slower pace of deregulation indicate that a lot is changing in our world. Yet, Constellation Energy is operating from a position of strength with a very solid balance sheet. We have taken a series of decisive actions, all of which are discussed in more detail in the Financial section of this report. We believe these actions will prove critical to ensuring the strength of the company's balance sheet in the future.

While we have a lot of work ahead, our success is ultimately in our own hands. With employees focused on crisp execution of our strategy, we indeed are in control of our own destiny. This is a long-term business, and Constellation Energy Group has proven that the same strength and flexibility that have sustained this company for more than 186 years will help us withstand virtually any challenge the future may bring.

That's cause for credit and applause for the many dedicated employees who helped us weather a turbulent 2001.

Before closing, we want to thank and bid farewell to five long-term board members who announced their retirement as of December 31, 2001: H. Furlong Baldwin, J. Owen Cole, Dan A. Colussy, Jerome W. Geckle, and George L. Russell, Jr.

All five combined have given 80 years of service to this company and provided impeccable leadership and guidance through the deregulation of Maryland's gas and electric industry and the formation of our merchant energy business.

Sincerely,

Mayo A. Shattuck III
President &
Chief Executive Officer

Christian H. Poindexter
Chairman of the Board

March 25, 2002

Constellation Energy Group owns energy-related businesses, including a North American wholesale power marketing and merchant generation business, and the Baltimore Gas and Electric Company (BGE), a regulated energy delivery company in Central Maryland. In 2001, combined revenues totaled $3.9 billion.

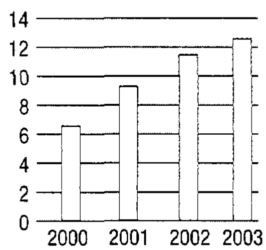
Merchant Energy

Our merchant energy business has two main parts: ***Generation and Marketing***

Constellation Generation Group: Owns and operates our fleet of power plants and generates the megawatts (MW) that we sell into the wholesale market.

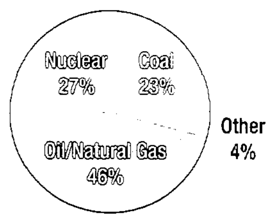
Key Facts

Generating Capacity
(thousands of MWs)



Constellation Generation Group owns and operates 9,200 MWs as of year-end 2001; by year-end 2003, it will own and operate more than 12,000 MWs.

2003 Fuel Mix
(MWs of Capacity)



Constellation Generation Group manages a diverse portfolio of plants that maintains a balanced fuel mix and geographic and dispatch diversity.

2001 Highlights

- Acquired Nine Mile Point Nuclear Station in November resulting in the ownership of an additional 1,550 megawatts
- Brought on-line more than 1,100 megawatts of natural gas-fired peaking plants at four sites (West Virginia, Virginia, Illinois, and Pennsylvania)
- Owned and operated 9,200 megawatts of generation, with an annualized capacity output of 47,300 gigawatt-hours
- Had under construction four new plants in Florida, Illinois, Texas, and California that combined will add nearly 2,900 megawatts by the end of 2003

Constellation Power Source: Oversees our power marketing, origination, and risk management operations and is responsible for selling every wholesale megawatt-hour Constellation Generation Group produces and managing all the associated market-hedgeable risk.

Key Facts

- Serves wholesale customers, including distribution utilities, co-ops, municipalities, and other large, load-serving companies that operate in deregulated energy markets, providing capacity, energy, and related products and services
- Serves significant volumes of the wholesale peak load in the Northeast, Mid-Atlantic, and Texas
- Enhances our generation assets by providing access to national markets, market infrastructure, real-time market intelligence, risk management and arbitrage opportunities, and transmission and transportation expertise

2001 Highlights

- Expanded its load-serving business in Texas by completing a strategic alliance with TNP Enterprises, Inc., for managing the Texas power resource needs of its two subsidiaries, Texas-New Mexico Power Company and First Choice Power
- Expanded its total load-serving business in the Northeast, Mid-Atlantic, and Texas to an expected peak of more than 14,000 megawatts in 2002
- Signed long-term power sales contracts with California Department of Water Resources and Florida's Seminole Electric Cooperative and Florida Power & Light to sell power from two of our plants under construction—the High Desert plant in Southern California and the Oleander plant near Cocoa, Florida

- *Our merchant energy business* currently owns 9,200 megawatts of generating capacity nationwide and focuses on serving wholesale customers (distribution utilities, co-ops, municipalities and other large, load-serving companies) that operate in deregulated energy markets, including the Northeast and Mid-Atlantic regions, and Texas. It is also expanding its reach in Florida, Illinois, Texas, and California with four power plants under construction in those states.
- *Our regulated energy delivery business, BGE,* delivers energy throughout its 2,300-square-mile electric and 800-square-mile gas service territory in Central Maryland and is a member of the PJM Interconnection, which serves the Pennsylvania, New Jersey, Maryland region.
- *Our other retail energy services businesses* include Constellation Energy Source, which provides customized energy solutions exclusively to commercial and industrial customers, and BGE Home Products & Services, which provides home products, commercial building systems, and residential and commercial electric and gas retail marketing.

Regulated Energy Delivery

Baltimore Gas and Electric Company (BGE): Delivers energy to more than 1.1 million electric customers and 600,000 gas customers throughout Central Maryland.

Key Facts

Electric Transmission and Distribution

- Operates in the PJM Interconnection and maintains nearly 21,500 circuit miles of distribution lines and almost 1,300 circuit miles of transmission lines in a 2,300-square-mile service territory

Natural Gas Distribution

- Stores and delivers natural gas through two peak-shaving plants, 10 gate stations, and nearly 6,000 miles of gas main in an over 800-square-mile service territory; natural gas suppliers include Columbia Gas Transmission Corporation, Transcontinental Gas Pipeline Corporation, and Dominion Transmission

2001 Highlights

- Reported its best year ever for average interruptions per customer, beating by 15% its previous all-time-best reliability record set in 2000
- Locked in wholesale power supply contracts with Constellation Power Source and Allegheny Energy Supply Company, LLC, ensuring it can meet its obligation as provider of last resort through the end of the transition to customer choice in 2006
- Embarked on a new initiative—Achieving Operational Excellence—to enhance financial and operational performance while increasing customer satisfaction, reliability and productivity, and reducing costs

Together, strength and flexibility are the formula for our success.

In an industry buffeted by unpredictable forces, ranging from regulatory uncertainty to the bankruptcy of industry "leaders" such as PG&E and Enron, success can be measured by the ability to withstand powerful forces and prosper under challenging conditions. It can also be measured in a commitment to values that have stood the test of time: service excellence, reliability, integrity, respect for the environment, and involvement in the community.

On these pages are some of our 2001 success stories.

They include the expansion of our power generation fleet and a continued focus on risk management and customized approaches to supply the needs of wholesale energy customers. They also include significant reliability improvements and business milestones achieved by our utility operations, as well as some of our notable accomplishments in community outreach and environmental stewardship.

From the momentum gained from last year, we expect our strength and flexibility to bring us even greater success in 2002 and beyond.

the formula for

Constellation Power Source is a major electric supplier in Maine.

Supplier of Choice

In deregulated energy markets like New England's, customers can choose their electric supplier. Those not making a choice receive a fixed-rate energy supply, or standard offer service, from their utility. To meet that obligation, electric distribution utilities have turned to companies like Constellation Power Source, our origination and risk management business.

Last September, the Maine Public Utilities Commission chose Constellation Power Source to provide the standard-offer-service energy supply to 550,000 residential and small-business customers in the state. The three-year contract runs through February of 2005 and fits nicely with our overall strategy to be a key player in the national merchant energy market.

Constellation Power Source manages risk for large, load-serving customers (such as utilities and municipalities), including their exposure to volatile energy prices. Balanced by owned or controlled generation assets, it designs the wholesale products and services necessary for the emerging competitive marketplace.

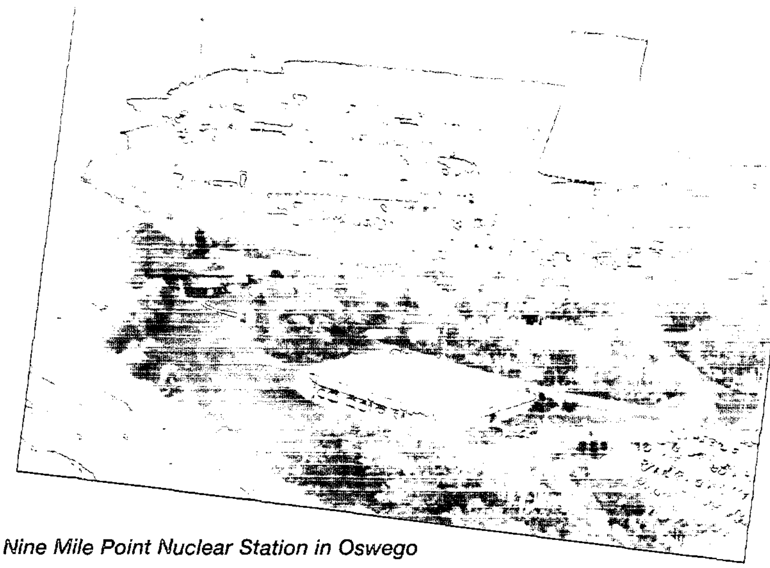
Focusing on deregulated regions, Constellation Power Source has gained a major foothold in key markets, including:

- The Northeast, where contracts like the one in Maine have made it one of the major regional suppliers;
- Maryland, where it won the competitively bid contract to supply 90% of BGE's standard-offer-service electric load from July 1, 2003, through June 30, 2006—an extension of its current contract to serve 100% of BGE's standard offer service through June 30, 2003; and
- Texas, where it forged a special alliance with TNP Enterprises, Inc., for managing the Texas power resource needs of its two subsidiaries, Texas-New Mexico Power Company and First Choice Power.

Through transactions like these, we have built a strong platform for growth. □

Powering Success

Constellation Energy's balanced portfolio of power plants provides us with the flexibility to meet our wholesale customers' energy needs. With plants located strategically across the country, our portfolio includes a balanced mix of nuclear, coal, natural gas, and renewable plants that have diverse dispatch capabilities.



Nine Mile Point Nuclear Station in Oswego County, New York, is the largest addition to our merchant fleet.

Balanced Growth

In 2001, the power behind Constellation's merchant energy business continued to grow. In the fall, Constellation completed the acquisition of the Nine Mile Point Nuclear Station in New York State. Also, last summer we added more than 1,100 megawatts, bringing on-line four new gas-fired peaking plants in strategic markets from Illinois to Virginia and Pennsylvania.

We are continuing our balanced growth trend with four gas-fired power plants currently under construction in California, Texas, Florida and Illinois that are scheduled to come on-line, adding another 2,900 megawatts to our competitive generation portfolio by the end of 2003.

success

Strong Operations

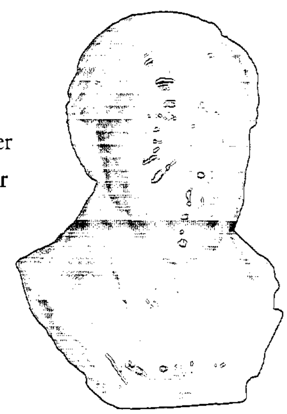
The flexibility in our growing portfolio is enhanced by strong performances at our existing power plants.

Our Calvert Cliffs plant had its second-best year ever in terms of power production and continued to rank among the best in worker safety. Plus, two of the plant's four new steam generators arrived last year. Workers will replace the steam generators in 2002 (Unit 1) and 2003 (Unit 2) and make other major upgrades that will help the plant continue to safely generate clean electricity for many years to come.

On the fossil fuel side, our nine Baltimore-based plants produced 14.7 million-megawatt-hours in 2001—a 2% increase over 2000. While maintaining one of the lowest forced outage rates in their history, these plants also implemented a number of process improvement programs to reduce costs and be more competitive.

Nuclear: A Banner Year

The momentum created by the historic license renewal of our Calvert Cliffs Nuclear Power Plant in 2000 carried over into 2001. In the spring, we received our industry's highest honor—the Edison Electric Institute's Edison Award. This prestigious award recognized our pioneering work as the first commercial nuclear plant in the country to be authorized to operate for an additional 20 years by the U.S. Nuclear Regulatory Commission.



Constellation Energy, EEI's Edison Award winner in 2001

Our standing as an industry leader in safety and performance made a difference in our purchase of Nine Mile Point. Niagara Mohawk Power Corporation—one of the sellers—and the New York Public Service Commission cited our reputation for performance, safety, and environmental stewardship as major reasons why Constellation won the bid. □

BGE Keeps on Delivering

Solid, predictable revenue for shareholders ... Significant improvements in reliability ... Smart and profitable growth ... BGE had quite a year.

A Strong Year for Reliability

Delivering reliable electric service to more than 1.1 million customers in Central Maryland is no small feat. In 2001, BGE made significant strides with its reliability initiatives, reporting its best year ever for average interruptions per customer. In fact, it improved upon its previous all-time best record set in 2000 by 15%.

Fewer outages can mean happier customers. That's why BGE has made significant investments over the past seven years to improve the reliability of its electric delivery system. Customers have enjoyed the results, witnessing steady reductions in the number of service interruptions experienced.

In addition to instituting a comprehensive preventative maintenance program, BGE has also installed innovative information technology that improves service and reduces costs. This year, BGE's new ATLAS and Outage Management systems will be up and running. By deploying advanced information technology in the operation of its electric and gas distribution networks, BGE will deliver improved relaibility and save millions of dollars in operating costs.

Wires Down! Red Alert!
Don't go near, you'll get hurt. Get some help, better rush. And do not, do not, do not touch!

Two BGE public service TV spots teaching children to stay away from downed wires garnered numerous awards in 2001, including an Emmy. □

Operational Excellence is the Future

When BGE's Gas Division signed its 600,000th gas customer in 2001, there was reason to celebrate. Achieving this major milestone was not just about growth; it represented the company's commitment to growing smartly and profitably.

That commitment is the foundation for a new initiative BGE embraced in 2001—Achieving Operational Excellence (AOE). Aimed at improving productivity while reducing and controlling costs, AOE has become the blueprint for making BGE a leader in energy delivery.

After a comprehensive and concerted effort to review and re-engineer key business processes in 2001, BGE has now begun to implement the more than 200 recommendations that came out of the process. Combined, the recommendations promise to substantially improve business processes, functions and activities while providing customers with more efficient, effective, and hassle-free service. ■

Serving the Communities Where We Work

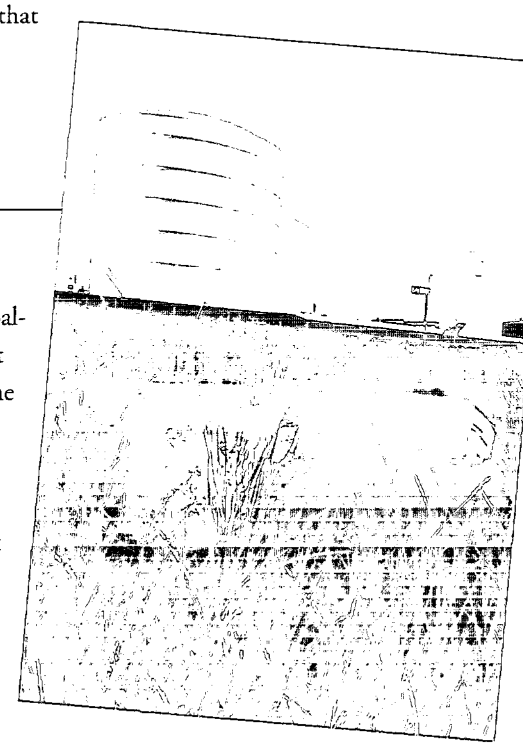
Despite a year of national turmoil and uncertainty, Constellation Energy and its employees remain constant in their commitment to the community. Below are some of the ways we responded to those in need in 2001:

- We continued our regional leadership in supporting the United Ways of Maryland, increasing our donation for the fourth consecutive year with a combined pledge of almost $2.5 million.
- We again rolled up our sleeves to donate more than 4,000 units of blood, a 46% employee participation rate that is the highest among private-sector employers in the Maryland region. It's no surprise that for more than 40 years the American Red Cross has relied on our employees for much of our region's needed blood supply.
- We translated our grief over the September 11th attacks into support for its heroes. In addition to a corporate donation to United Way of New York City's September 11th Fund, employees also gave victims their money, time, and blood.
- We volunteered hundreds of hours and raised thousands of dollars to support charities such as Special Olympics and the March of Dimes, and local initiatives including community shelters and literacy programs.
- We contributed corporately almost $4.7 million to community-strengthening initiatives that have proven to have a positive impact on education, economic development, and the environment in the areas where we operate. □

Protecting the Environment

Recognized for our environmental stewardship, Constellation Energy bridges the gap between protecting natural resources and creating a better quality of life for customers. Here are some notable accomplishments that will have a positive, long-lasting effect on the environment:

- Constellation Energy received the 2001 WasteWise Partner of the Year Award—the U.S. Environmental Protection Agency's highest honor for its voluntary program to reduce municipal solid waste. We were cited for our innovative and cost-effective new programs to prevent waste, increase recycling, and boost expenditures on recycled-content products.
- Constellation Generation's Safe Harbor hydroelectric plant in Pennsylvania, of which we have two-thirds ownership, received that state's Governor's Environmental Excellence Award. Recognized for its river-borne debris removal program, the plant uses a floating harvester to collect trash and refuse in the Susquehanna River, a tributary of the Chesapeake Bay, and brings it to shore for sorting and recycling.
- Constellation Generation's Brandon Shores power plant significantly reduced its air emissions. Located outside of Baltimore, it is the company's largest coal-burning facility. Last year, it completed the installation of two selective catalytic reduction (SCR) reactors. SCRs work like the catalytic converter in your car to reduce nitrogen oxide (NOx) emissions—known to contribute to the formation of ground-level ozone or smog. Brandon Shores is now capable of achieving a 90% NOx reduction and ranks as one of the country's cleanest coal-burning plants of its size. □



Located in the Chesapeake Bay Critical Area, our Spring Gardens natural gas facility won Baltimore's 2001 Mayor's Business Recognition Award for our site reforestation and clean-up efforts.

In October 2001, Constellation Energy Group's Board of Directors elected Mayo A. Shattuck III President and Chief Executive Officer. Not your everyday utility CEO, Shattuck came to Constellation with a unique and powerful background of success in fields vital to the changing energy business—capital markets, trading, investment banking, and corporate finance.

He joined the company after leaving his position as Chairman of Deutsche Banc Alex. Brown, the successor company to the nation's oldest investment bank, Alex. Brown & Sons, where he had been President. Earlier in his career at Alex. Brown, he headed the firm's Technology Group, which managed several landmark initial public offerings including Microsoft, AOL, Sun Microsystems, and Oracle.

Shattuck says that his priority has always been, and always will be, creating shareholder value. In the following question and answer session, he articulates how his vision and unique skills will make that priority a reality at Constellation Energy Group.

a conversation with

You're the company's first CEO who has been hired from the outside. What perspective do you bring that's important in today's energy marketplace?

I really feel fortunate to be following in a long line of leaders who have helped transform and steward this great company for almost two centuries. Chris Poindexter has managed the company through its most challenging deregulatory years, and this management team is particularly grateful to have his ongoing guidance as Chairman and as an influential industry leader in the many trade and regulatory issues we face.

I assumed my new role at Constellation Energy during a time of great upheaval for this industry. In effect, we are experiencing the collapse of a speculative bubble. Bubbles are created when financial markets allow too much capital to flow to specific industries or ideas without sufficient pickup in demand to meet the new level of supply.

It isn't difficult to find evidence of this in the power industry: the collapse of Enron and subsequent rating agencies' actions; an expected oversupply in generation capacity; efforts across the industry to cut new generation spending and turbine orders, and to sell non-core assets; and finally, a retrenchment in expectations for earnings growth.

I've seen similar bubbles and, over the years, I've learned that, regardless of the industry, a management team needs to focus on its strengths and intensify the focus on managing risk to successfully navigate through a transition period like the one we are experiencing.

In my first several months on the job, we've taken steps to address the weaknesses that have hindered our performance in the past. We have reorganized the management structure and reinvigorated the organization to focus on execution and our ability to manage risk in a prudent and responsible way.

We now have a Chief Risk Officer as a part of our executive management team. Why did you create that position?
Success in today's energy market is all about managing risk, a task that has become vastly more complex over the past several years. Volatility in fuel costs and power prices, congestion in transmission, illiquidity in financial markets, and many other factors all contribute to a much more dynamic business model.

We have to be smart in how we define and manage risk. That's why I elevated the position of Chief Risk Officer to a

The benefits of Constellation's more stable businesses—like our utility and our generating plants—are that their solid cash flow and earnings balance the growth potential of our new origination business.

In effect, our decision not to separate helped preserve a portfolio of businesses that, when married together, create a nice balance between stability and growth. That allows us to be competitive on multiple fronts going forward.

Mayo Shattuck III

corporate level, much the way I've managed risk at large financial institutions in the past.

The Chief Risk Officer reports directly to me and is responsible for defining our risk from a corporate portfolio standpoint. He bridges all business lines in an independent fashion and systematically identifies the risks that each part of our business faces daily so we can proactively make decisions about what we want to pursue. He also makes sure we're continually and vigilantly assessing the credit risk of the many counterparties with which we deal.

One of the reasons given for not separating is the importance of having a strong balance sheet. How has that helped set us apart from the pack today?
Creditworthiness is a critical element of our strategic position. To grow and take advantage of opportunities, it's important to have balanced sources of net income and a strong balance sheet.

The failure of deregulation in California and then the collapse of Enron have had a dramatic impact on the industry. What makes Constellation Energy different from the rest of the sector?
First, Constellation Energy is not even close to Enron in terms of the type of business we run and the way in which we behave. The best energy businesses have physical assets to complement their merchant capabilities and they maintain strong customer relationships. That's what our company has and plans to preserve. In short, we have real assets, real customers, and a real business that has staying power.

We take the issue of disclosure very seriously. We have worked hard to ensure we provide our shareholders with the information they need to understand our financials and the factors that could affect our earnings results. It used to be that the weather was the main source of quarterly earnings variability. Today there are many other factors. Our goal is to keep our shareholders informed while we build a business that is viable over the very long term.

continued on next page

It's also important to understand that Maryland is not California in terms of deregulation. Since implementing electric customer choice in July 2000, Maryland has been spared the problems associated with deregulation in California.

Today, all BGE customers have a choice as to their energy commodity suppliers. As the provider of last resort, BGE locked in wholesale power supply contracts in 2001 with Constellation Power Source and Allegheny Energy Supply Company, LLC. These contracts ensure the utility can meet its obligation to provide power through June 2006 at rates and terms set by the Maryland Public Service Commission's 1999 Restructuring Order.

What makes certain regions more attractive than others for our business?

Our merchant energy business is focused on the national wholesale market. It serves customers—including distribution utilities, co-ops, municipalities, and other large, load-serving companies—that operate in regions that have meaningfully deregulated their retail energy markets.

That is why we have built a significant presence in the Northeast and Mid-Atlantic regions, and Texas. Over the next two years, we plan to continue to grow our load-serving market positions in these regions and expand beyond as we bring on plants in Florida, Texas, Illinois, and California.

What kind of growth do you see for our company?

We have set a long-term goal of growing earnings per share from organic sources at 10% a year, and we have a solid plan to achieve that. About 30% of our earnings still come from our regulated energy delivery business, while our competitive wholesale merchant energy business contributes nearly 70%. If we combine the share price appreciation, which should result from our earnings growth, with our new 3% dividend yield, we hope to achieve an overall total shareholder return of 13% or more.

What challenges do we face in meeting our growth targets?

The most important thing we have to do is execute well. We also must be ever more vigilant about making sure we have the best competitive cost structure in the industry. And we must leverage our human capital. Providing we do those things and improve the valuation of the company, we will be in control of our own destiny.

Are mergers and acquisitions a part of our future? Are you planning on building or acquiring more power plants to continue to strengthen your generating asset portfolio?

Our strategy is to grow the merchant energy business, so we are focused on merchant energy-related assets that support our customer-focused origination business. We evaluate all opportunities against a strict set of criteria. We are only looking for acquisitions that provide strong return to our shareholders.

Constellation Energy Group has been a leader in the nuclear industry. What role will nuclear play in the company's future?

Nuclear generation remains one of our core competencies and an important part of our balanced portfolio of generating assets. We will continue to maintain a commitment to excellence at our two nuclear stations, which comprise more than 3,200 megawatts of our total 9,200-megawatt portfolio.

Toward that end, our Calvert Cliffs plant is replacing its four steam generators. Once the project is complete, the plant can continue to safely generate clean electricity for many years to come.

In addition, we are embarking on a long-term performance improvement plan at our Nine Mile Point plant and initiating a license renewal effort. Our goal is to take this asset to the next level in terms of safety, reliability, capacity factors, and productivity.

How does the future look for Constellation Energy Group?

This company has some very bright prospects. I believe that it is well-positioned to emerge from this period of uncertainty as a strong company with solid building blocks for growth. Our core strengths—high quality assets, the right people to operate them, and a strong balance sheet—will be the platform for that growth. □

Contents

financial report

Forward Looking Statements

We make statements in this report that are considered forward looking statements within the meaning of the Securities Exchange Act of 1934. Sometimes these statements will contain words such as "believes," "expects," "intends," "plans," and other similar words. These statements are not guarantees of our future performance and are subject to risks, uncertainties, and other important factors that could cause our actual performance or achievements to be materially different from those we project. These risks, uncertainties, and factors include, but are not limited to:

- the timing and extent of changes in commodity prices for energy including coal, natural gas, oil, and electricity,
- the timing and extent of deregulation of, and competition in, the energy markets in North America, and the rules and regulations adopted on a transitional basis in those markets,
- the conditions of the capital markets generally, which are affected by interest rates and general economic conditions, as well as Constellation Energy and BGE's ability to maintain their current credit ratings,
- the effectiveness of Constellation Energy's risk management policies and procedures and the ability of our counterparties to satisfy their financial commitments,
- the liquidity and competitiveness of wholesale markets for energy commodities,
- operational factors affecting the start-up or ongoing commercial operations of our generating facilities (including nuclear facilities) and BGE's transmission and distribution facilities, including catastrophic weather related damages, unscheduled outages or repairs, unanticipated changes in fuel costs or availability, unavailability of gas transportation or electric transmission services, workforce issues, terrorism, liabilities associated with catastrophic events, and other events beyond our control,
- the inability of BGE to recover all its costs associated with providing electric retail customers service during the electric rate freeze period,
- the effect of weather and general economic and business conditions on energy supply, demand, and prices,
- regulatory or legislative developments that affect demand for energy, or increase costs, including costs related to nuclear power plants, safety, or environmental compliance,
- the actual outcome of uncertainties associated with assumptions and estimates using judgment when applying critical accounting policies and preparing financial statements, including factors that are estimated in applying mark-to-market accounting, such as variable contract quantities and the value of mark-to-market assets and liabilities determined using models,
- cost and other effects of legal and administrative proceedings that may not be covered by insurance, including environmental liabilities, or the outcome of pending appeals regarding the Maryland Public Service Commission's (Maryland PSC) orders on electric deregulation, and the transfer of BGE's generation assets to affiliates, and
- operation of our generation assets in a deregulated market without the benefit of a fuel rate adjustment clause.

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

Changes may occur after that date, and we do not assume responsibility to update these forward looking statements.

	2001	2000*	1999	1998	1997
Merchant Energy					
Mark-to-Market Energy Assets *(In millions)*	$2,218.2	$2,522.4	$373.4	$133.0	$ 9.4
Mark-to-Market Energy Liabilities *(In millions)*	1,799.8	1,994.5	225.1	99.0	8.6
Revenues *(In millions)*					
Standard Offer Service Revenue from BGE	$1,269.0	$ 691.0	$ –	$ –	$ –
Other Generation Revenue	314.1	171.9	124.3	129.4	108.1
Mark-to-Market Energy Revenues	175.8	151.5	147.7	47.5	2.6
Other Revenue	6.6	11.3	5.3	6.7	2.3
Total Revenue	$1,765.5	$1,025.7	$277.3	$183.6	$113.0
Generated *(In millions)*—MWH	37.4	18.8	1.3	1.3	1.2
Regulated Utility					
Electric Operating Statistics					
Revenues *(In millions)*					
Residential	$ 885.3	$ 922.6	$ 975.2	$ 948.6	$ 932.5
Commercial	903.0	926.2	939.3	912.9	892.6
Industrial	218.1	203.6	204.3	211.5	211.9
System Sales	2,006.4	2,052.4	2,118.8	2,073.0	2,037.0
Interchange and Other Sales	–	53.8	112.1	120.8	132.7
Other	33.6	29.0	29.1	27.0	22.3
Total	$2,040.0	$2,135.2	$2,260.0	$2,220.8	$2,192.0
Sales *(In thousands)*—MWH					
Residential	11,714	11,675	11,349	10,965	10,806
Commercial	14,147	14,042	13,565	13,219	12,718
Industrial	4,445	4,476	4,350	4,583	4,575
System Sales	30,306	30,193	29,264	28,767	28,099
Interchange and Other Sales	–	2,064	4,785	5,454	6,224
Total	30,306	32,257	34,049	34,221	34,323
Customers *(In thousands)*					
Residential	1,040.5	1,033.4	1,021.4	1,009.1	1,001.0
Commercial	110.9	108.9	107.7	106.5	105.9
Industrial	5.0	5.0	4.7	4.6	4.5
Total	1,156.4	1,147.3	1,133.8	1,120.2	1,111.4
Average Use per Residential Customer—KWH	11,257	11,297	11,111	10,866	10,794
Average Rate per KWH (System Sales)—¢					
Residential	7.56	7.90	8.59	8.65	8.63
Commercial	6.38	6.60	6.92	6.91	7.02
Industrial	4.91	4.55	4.70	4.62	4.63

Operating statistics do not reflect the elimination of intercompany transactions.

continued on next page

**Operating statistics reflect generation function as part of regulated electric operations through June 30, 2000.*

	2001	2000	1999	1998	1997
Gas Operating Statistics					
Revenues *(In millions)*					
Residential —Excluding Delivery Service	$378.4	$328.4	$298.1	$279.2	$321.7
—Delivery Service	16.3	23.5	11.5	4.9	0.5
Commercial —Excluding Delivery Service	115.5	97.9	79.3	75.6	113.5
—Delivery Service	21.4	25.8	24.4	19.4	12.9
Industrial —Excluding Delivery Service	12.8	10.9	8.2	8.0	11.4
—Delivery Service	13.8	16.3	16.1	16.0	17.2
System Sales	558.2	502.8	437.6	403.1	477.2
Off-System Sales	113.6	101.0	42.9	40.9	37.5
Other	8.9	7.8	7.6	7.1	6.9
Total	$680.7	$611.6	$488.1	$451.1	$521.6
Sales *(In thousands)*—DTH					
Residential —Excluding Delivery Service	33,147	34,561	34,272	33,595	39,958
—Delivery Service	7,201	9,209	4,468	1,890	205
Commercial —Excluding Delivery Service	12,334	13,186	11,733	11,775	18,435
—Delivery Service	25,037	22,921	20,288	16,633	12,964
Industrial —Excluding Delivery Service	1,386	1,386	1,367	1,412	2,016
—Delivery Service	23,872	32,382	33,118	34,798	38,791
System Sales	102,977	113,645	105,246	100,103	112,369
Off-System Sales	20,012	22,456	15,543	16,724	14,759
Total	122,989	136,101	120,789	116,827	127,128
Customers *(In thousands)*					
Residential	558.7	553.7	543.5	532.5	524.5
Commercial	40.2	40.1	39.9	39.6	39.3
Industrial	1.4	1.4	1.3	1.3	1.3
Total	600.3	595.2	584.7	573.4	565.1
Average Rate per Therm—$					
Residential —Excluding Delivery Service	1.14	.95	.87	.83	.81
Commercial —Excluding Delivery Service	.94	.74	.68	.64	.62
Industrial —Excluding Delivery Service	.93	.79	.60	.57	.57
Peak Day Sendout *(In thousands)*—DTH	668.6	795.7	727.8	658.4	765.0
Peak Day Capability *(In thousands)*—DTH	937.8	825.1	836.6	833.0	870.0

Operating statistics do not reflect the elimination of intercompany transactions.

	2001	2000	1999	1998	1997
	(Dollar amounts in millions, except per share amounts)				
Summary of Operations					
Total Revenues	$3,928.3	$3,852.5	$3,840.9	$3,386.4	$3,307.6
Total Expenses	3,570.5	3,009.9	3,081.0	2,647.9	2,584.0
Income From Operations	357.8	842.6	759.9	738.5	723.6
Other Income (Expense)	1.3	4.2	7.9	5.7	(52.8)
Income Before Fixed Charges and Income Taxes	359.1	846.8	767.8	744.2	670.8
Fixed Charges	238.8	271.4	255.0	260.6	258.7
Income Before Income Taxes	120.3	575.4	512.8	483.6	412.1
Income Taxes	37.9	230.1	186.4	177.7	158.0
Income Before Extraordinary Item and Cumulative Effect of Change in Accounting Principle	82.4	345.3	326.4	305.9	254.1
Extraordinary Loss, Net of Income Taxes	–	–	(66.3)	–	–
Cumulative Effect of Change in Accounting Principle, Net of Income Taxes	8.5	–	–	–	–
Net Income	$ 90.9	$ 345.3	$ 260.1	$ 305.9	$ 254.1
Earnings Per Common Share and Earnings Per Common Share—Assuming Dilution Before Extraordinary Item and Cumulative Effect of Change in Accounting Principle	$ .52	$2.30	$2.18	$2.06	$1.72
Extraordinary Loss	–	–	(.44)	–	–
Cumulative Effect of Change in Accounting Principle	.05	–	–	–	–
Earnings Per Common Share and Earnings Per Common Share—Assuming Dilution	$ .57	$2.30	$1.74	$2.06	$1.72
Dividends Declared Per Common Share	$ .48	$1.68	$1.68	$1.67	$1.63
Summary of Financial Condition					
Total Assets	$14,077.6	$12,939.3	$9,745.1	$9,434.1	$8,900.0
Short-Term Borrowings	$ 975.0	$ 243.6	$ 371.5	$ –	$ 316.1
Current Portion of Long-Term Debt	$ 1,406.7	$ 906.6	$ 808.3	$ 541.7	$ 271.9
Capitalization					
Long-Term Debt	$ 2,712.5	$ 3,159.3	$2,575.4	$3,128.1	$2,988.9
Redeemable Preference Stock	–	–	–	–	90.0
Preference Stock Not Subject to Mandatory Redemption	190.0	190.0	190.0	190.0	210.0
Common Shareholders' Equity	3,843.6	3,174.0	3,017.5	2,995.9	2,876.4
Total Capitalization	$ 6,746.1	$ 6,523.3	$5,782.9	$6,314.0	$6,165.3
Financial Statistics at Year End					
Ratio of Earnings to Fixed Charges	1.18	2.78	2.87	2.60	2.35
Book Value Per Share of Common Stock	$23.48	$21.09	$20.17	$20.08	$19.47

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

Introduction

Constellation Energy Group, Inc. (Constellation Energy) is a North American energy company that conducts its business through various subsidiaries including a merchant energy business and Baltimore Gas and Electric Company (BGE). Our merchant energy business generates and markets wholesale electricity in North America. BGE is an electric and gas public utility company with a service territory that covers the City of Baltimore and all or part of ten counties in central Maryland. We describe our operating segments in Note 3 on page 66.

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. Also, on July 1, 2000, BGE transferred all of its generation assets and related liabilities at book value to our merchant energy business. As a result, the financial results of the electric generation portion of our business are included in the merchant energy business beginning July 1, 2000. Prior to July 1, 2000, the financial results of electric generation were included in BGE's regulated electric business. We discuss the deregulation of electric generation in the *Business Environment* section on page 25.

Our merchant energy business includes:

- fossil, nuclear, and hydroelectric generating facilities, interests in domestic power projects, and nuclear consulting services, and
- power marketing, origination transactions, and risk management services.

BGE is a regulated electric and gas public transmission and distribution utility company.

Our other nonregulated businesses include:

- energy products and services,
- home products, commercial building systems, and residential and commercial electric and gas retail marketing,
- a general partnership, in which BGE is a partner, that provides cooling services for commercial customers in Baltimore,
- financial investments,
- real estate and senior-living facilities, and
- interests in Latin American power generation and distribution projects and investments.

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

- what factors affect our businesses,
- what our earnings and costs were in the years presented,
- why earnings and costs changed between years,
- where our earnings came from,
- how all of this affects our overall financial condition,
- what our expenditures for capital projects were for 1999 through 2001, 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 on page 49, which present the results of our operations for 2001, 2000, and 1999. We analyze and explain the differences between periods in the specific line items of the Consolidated Statements of Income.

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 merchant energy business, and we entered into retail customer choice for electric generation effective July 1, 2000. Accordingly, the results of operations and financial condition described in this discussion and analysis are not necessarily indicative of future performance.

Critical Accounting Policies

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

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

These estimates involve judgments with respect to, 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.

The Securities and Exchange Commission (SEC) recently issued disclosure guidance for accounting policies that management believes are most "critical." The SEC defines these critical accounting policies as those that are both most important to the portrayal of a company's financial condition and results and require management's most difficult, subjective, or complex judgment, often as a result of the need to make estimates about the effect of matters that are inherently uncertain and may change in subsequent periods.

Management believes the following accounting policies require us to use more significant judgments and estimates in preparing our financial statements and could represent critical accounting policies as defined by the SEC. We discuss our significant accounting policies, including those that do not require management to make difficult, subjective, or complex judgments or estimates, in Note 1 on page 57.

Revenue Recognition/Mark-to-Market Method of Accounting

Our subsidiary, Constellation Power Source, uses the mark-to-market method of accounting to account for a portion of its power marketing activities. We record all other revenues in the period earned for services rendered, commodities or products delivered, or contracts settled.

Power marketing activities include new origination transactions and risk management activities using contracts for energy, other energy-related commodities, and related derivative contracts. We use the mark-to-market method of accounting for portions of Constellation Power Source's activities as required by EITF 98-10, *Accounting for Contracts Involved in Energy Trading and Risk Management Activities.* Under the mark-to-market method of accounting, we record the fair value of commodity and derivative contracts as mark-to-market energy assets and liabilities at the time of contract execution. We record reserves to reflect uncertainties associated with certain estimates inherent in the determination of fair value. Mark-to-market energy revenues include:

- the fair value of new transactions at origination,
- unrealized gains and losses from changes in the fair value of open positions,
- net gains and losses from realized transactions, and
- changes in reserves.

We record the changes in mark-to-market energy assets and liabilities on a net basis in "Nonregulated revenues" in our Consolidated Statements of Income. Mark-to-market energy assets and liabilities are comprised of a combination of energy and energy-related derivative and non-derivative contracts. While some of these contracts represent commodities or instruments for which prices are available from external sources, other commodities and certain contracts are not actively traded and are valued using modeling techniques to determine expected future market prices, contract quantities, or both. The market prices used to determine fair value reflect management's best estimate considering various factors, including closing exchange and over-the-counter quotations, time value, and volatility factors. However, it is possible that future market prices could vary from those used in recording mark-to-market energy assets and liabilities, and such variations could be material.

Certain power marketing and risk management transactions entered into under master agreements and other arrangements provide our merchant energy business with a right of setoff in the event of bankruptcy or default by the counterparty. We report such transactions net in the balance sheets in accordance with FASB Interpretation No. 39, *Offsetting of Amounts Related to Certain Contracts.*

We discuss the impact of mark-to-market accounting on our financial results in the *Results of Operations—Merchant Energy Business* section on page 30.

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

We are required to evaluate certain assets that have long lives (generating property and equipment and real estate) to determine if they are impaired if certain conditions exist. We determine if long-lived assets are impaired by comparing their undiscounted expected future cash flows to their carrying amount in our accounting records. We would record an impairment loss if the undiscounted expected future cash flows from an asset were less than the carrying amount of the asset. Additionally, we evaluate our equity-method investments to determine whether they have experienced a loss in value that is considered other than a temporary decline in value.

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

Events of 2001

In the past year, the utility industry and energy markets experienced significant changes as a result of the slowing of the U.S. economy, the significant declines in both the short-term and long-term market prices of electricity in certain regions, the events in California, the financial collapse of Enron Corporation (Enron), as well as the effects of the September 11, 2001 terrorist attacks, and the threat of additional attacks. We address certain of these issues in the *Business Environment* section on page 25.

In response to our changing business environment, we canceled our separation plans and terminated our power business services agreement with Goldman Sachs & Co. (Goldman Sachs) on October 26, 2001. We believe that maintaining our current corporate structure provides a better platform of size, strength, and stability from which to execute our strategies. As a result of the significant declines in market prices of electricity, we terminated all planned development projects not currently under construction.

Separately, we initiated efforts to reduce costs in order to become more competitive and to sell certain non-core assets in order to focus management's attention and our capital resources on our core energy businesses. We discuss our initiatives in more detail in this section. We continue to examine plans to achieve our strategies, and to further strengthen our balance sheet and enhance our liquidity.

Contract Termination Related Costs

We announced the termination of our power business services agreement with Goldman Sachs. We paid Goldman Sachs a total of $355 million, representing $196 million to terminate the power business services agreement with our power marketing operation and $159 million previously recognized as a payable for services rendered under the agreement. We issued commercial paper and borrowed under our existing bank lines to fund this payment. In the fourth quarter of 2001, we recognized expenses of approximately $224.8 million pre-tax, or $139.6 million after-tax, related to the termination of the contract with Goldman Sachs. Goldman Sachs also will not make an equity investment in our merchant energy business as previously announced. We discuss the termination of our power business services agreement with Goldman Sachs in Note 2 on page 65.

Sale of Guatemalan Operations

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

We decided to sell our Guatemalan operations to focus our efforts on our core energy businesses. As a result of this transaction, we are no longer committed to making significant future capital investments in this non-core operation. We recorded a pre-tax loss of $43.3 million, or $28.1 million after-tax, in the fourth quarter of 2001, resulting from this sale. We discuss this sale in Note 2 on page 65.

Workforce Reduction Programs

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

As a result, we recorded $105.7 million pre-tax, or $64.1 million after-tax, of expenses related to these programs during the fourth quarter of 2001. BGE recorded $57.0 million of the pre-tax amount as expense relating to its electric and gas businesses. BGE also recorded $19.5 million on its balance sheet as a regulatory asset of its gas business. We will continue cost-cutting measures to remain competitive in our business environment and expect to record approximately $35 million of additional expense in 2002 related to the programs implemented to date. As a result of our workforce reduction efforts to date, we expect annual cost savings of approximately $72 million.

We also expect that a significant number of retiring employees covered by our qualified, basic pension plan will elect to receive their pension benefit in the form of a lump-sum payment in 2002. These lump-sum payments may exceed annual plan service cost and interest expense that could trigger a settlement loss in 2002 estimated to be approximately $20 million.

We discuss our early retirement and severance programs in more detail in Note 2 on page 64, Note 6 on page 71, and Note 7 on page 72.

Impairment Losses and Other Costs

In the fourth quarter of 2001, our merchant energy business recorded impairments of $46.9 million pre-tax, or $30.5 million after-tax, primarily due to the termination of all planned development projects not currently under construction, including projects in Texas, California, Florida, and Massachusetts and due to a decline in value of an investment in a power project in Michigan. We decided to terminate our development projects due to the expected excess generation capacity in most domestic markets and the significant decline in the forward market prices of electricity. The impairments include costs associated with four turbines no longer expected to be placed in service.

In the fourth quarter of 2001, our other nonregulated businesses recorded $107.3 million pre-tax, or $69.7 million after-tax, in impairments of certain non-core assets as follows:

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

In addition, our financial investments business recorded a $4.6 million pre-tax, or $2.8 million after-tax, reduction of its investment in an aircraft due to the decline in value of used airplanes as a result of the September 11, 2001 terrorist attacks and the general downturn in the aviation industry.

We discuss these special costs further in Note 2 on page 65.

Acquisition of Nine Mile Point

On November 7, 2001, we completed our purchase of the Nine Mile Point Nuclear Station (Nine Mile Point) located in Scriba, New York. Nine Mile Point Nuclear Station, LLC, a subsidiary of Constellation Nuclear, purchased 100 percent of Nine Mile Point Unit 1 and 82 percent of Unit 2 for cash of $382.7 million including settlement costs and a sellers' note of $388.1 million to be repaid over five years with an interest rate of 11.0%. This note may be prepaid at any time without penalty. The sellers also transferred approximately $442 million in decommissioning funds. As a result of this purchase, we own 1,550 megawatts of Nine Mile Point's 1,757 megawatts of total generating capacity.

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

We discuss the acquisition of Nine Mile Point further in Note 14 on page 86.

Enron

On December 2, 2001, Enron Corporation filed for reorganization under Chapter 11 of the U.S. Bankruptcy Code. Our financial exposure to Enron is not material. Prior to the bankruptcy filing, our power marketing operation settled its positions with Enron and as a result has no direct credit exposure to Enron.

Bethlehem Steel

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

New President and Chief Executive Officer

Effective November 1, 2001, Mayo A. Shattuck, III was elected President and Chief Executive Officer of Constellation Energy. Christian H. Poindexter remains as Chairman of the Board. Mr. Shattuck has been a Director of Constellation Energy or a subsidiary for seven years. Prior to joining Constellation Energy, he was Global Head of Investment Banking for Deutsche Bank and Co-Chairman and Co-Chief Executive Officer of DB Alex. Brown and Deutsche Bank Securities.

Certain Relationships

Michael J. Wallace, prior to becoming President of Constellation Generation Group on January 1, 2002, was a Managing Member and Managing Director and greater than 10% owner of Barrington Energy Partners, LLC. Upon becoming President of Constellation Generation Group, Mr. Wallace terminated his affiliation with Barrington, and no longer holds any ownership interest in it. Barrington Energy Partners provided consulting services to Constellation Energy and its subsidiary, Constellation Nuclear during 2001, and is continuing to do so during 2002. We paid Barrington approximately $4.4 million in 2001.

Events of 2002

Dividend Increase

On January 30, 2002, we announced an increase in our quarterly dividend to 24 cents per share on our common stock payable April 1, 2002 to holders of record on March 11, 2002. This is equivalent to an annual rate of 96 cents per share. Previously, our quarterly dividend on our common stock was 12 cents per share, equivalent to an annual rate of 48 cents per share.

Investment in Orion

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

Investment in Corporate Office Properties Trust (COPT)

In March 2002, we sold all of our COPT equity-method investment, approximately 8.9 million shares, as part of a public offering. We received cash proceeds of $101.3 million on the sale, which approximates the book value of our investment.

Strategy

On October 26, 2001, we announced the decision to remain a single company and canceled prior plans to separate our merchant energy business from our other businesses and terminated our power business services agreement with Goldman Sachs as previously discussed in the *Events of 2001* section on page 22.

Our primary growth strategy centers on our merchant energy business. The strategy for our merchant energy business is to be a leading competitive provider of energy solutions for wholesale customers in North America. Our merchant energy business has electric generation assets located in various regions of the United States and engages in power marketing and risk management activities and provides energy solutions to meet wholesale customers' needs throughout North America.

Our merchant energy business integrates electric generation assets with power marketing and risk management of energy and energy-related commodities. This integration allows our merchant energy business to maximize value across energy products, over geographic regions, and over time. Our power marketing operation adds value to our generation assets by providing national market access, market infrastructure, real-time market intelligence, risk management and arbitrage opportunities, and transmission and transportation expertise. Generation capacity supports our power marketing operation by providing a source of reliable power supply, enhancing our ability to structure sophisticated products and services for customers, building customer credibility, and providing a physical hedge.

Currently, our merchant energy business controls over 11,500 megawatts of generation including the 1,550 megawatts of the nuclear generating capacity at Nine Mile Point and the 1,100 megawatts of natural gas-fired peaking capacity that commenced operations in the Mid-Atlantic and Mid-West regions during mid-summer 2001. We also have approximately 2,900 megawatts of natural gas-fired peaking and combined cycle production facilities under construction in Texas, California, Florida, and Illinois.

To achieve our strategic objectives, we expect to continue to support our power marketing and risk management operations with generation assets that have diversified geographic, fuel, and dispatch characteristics. We also expect to use a disciplined growth strategy through originating transactions with wholesale customers and by acquiring and developing additional generating facilities when necessary to support our power marketing operation.

Our merchant energy business will focus on long term, high-value sales of energy, capacity, and related products to distribution companies and other wholesale purchasers, primarily in the regional markets in which end user electricity rates have been deregulated and thereby separated from the cost of generation supply. These markets include the Northeast region, the Mid-Atlantic region, and Texas.

The growth of BGE and our retail energy services businesses is expected through focused and disciplined expansion.

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

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

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

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

Business Environment

With the shift toward customer choice, competition, and the growth of our merchant energy business, various factors will affect our financial results in the future. We discuss these various factors in the *Forward Looking Statements* section on page 17.

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

Electric Competition

We are facing competition in the sale of electricity in wholesale power markets and 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 PSC addressed the major provisions of the Act. The accompanying tax legislation is discussed in detail in Note 5 on page 69.

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 5 on page 69.

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

- All customers can choose their electric energy supplier. BGE 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.
- Constellation Power Source Generation issued approximately $366 million in unsecured promissory notes to BGE. All of these notes have been repaid by Constellation Power Source Generation. The proceeds were used 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 (July 1, 2000 to 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. Pursuant to the Restructuring Order, 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 (July 1, 2000 to June 30, 2003).

In August 2001, following a competitive bidding process, BGE entered into contracts with Constellation Power Source to provide 90% and Allegheny Energy Supply Company, LLC to provide the remaining 10% of the energy and capacity required for BGE to meet its standard offer service requirements for the final three years (July 1, 2003 to June 30, 2006) of the transition period. BGE awarded these contracts primarily based on price and access to the PJM region. The amount BGE pays for energy and capacity does not exceed the standard offer service rates received from customers. Over the transition period, the standard offer service rate that BGE receives from its customers increases. This is offset by a corresponding decrease in the competitive transition charge BGE receives.

Constellation Power Source obtains the energy and capacity to supply BGE's standard offer service obligations from nonregulated 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 if necessary.

Other States

Several states, other than Maryland, have supported complete deregulation of the electric industry. Other states that were considering deregulation have slowed their plans or postponed consideration. While our power marketing operation may be affected by the slow down in deregulation, the Federal Energy Regulatory Commission (FERC) initiatives regarding the formation of larger Regional Transmission Organizations could provide our merchant energy business other opportunities as discussed in the *FERC Regulation—Regional Transmission Organizations* section on page 28.

Our merchant energy business has $296.4 million invested in operating power projects of which our ownership percentage represents 146 megawatts of electricity that are sold to Pacific Gas & Electric (PGE) and to Southern California Edison (SCE) in California under power purchase agreements as discussed in the *California Power Purchase Agreements* section on page 32. Our merchant energy business was not paid in full for its sales from these plants to the two utilities from November 2000 through early April 2001. At December 31, 2001, our portion of the amount due for unpaid power sales from these utilities was approximately $45 million. We recorded reserves of approximately 20% of this amount.

These projects entered into agreements with PGE and SCE that provide for five-year fixed-price payments averaging $53.70 per megawatt-hour plus the stated capacity payments in the original Interim Standard Offer No. 4 (SO4) contracts. These agreements also provide for the payment of all past due amounts plus interest. As of the date of this report, we have received $28 million related to the $45 million of unpaid power sales, of which 100% of the SCE outstanding balance was paid. We expect to collect the remaining outstanding balance from PGE within the next year.

However, as a result of ongoing litigation before the FERC regarding sales into the spot markets of the California Independent System Operator (ISO) and Power Exchange, we may be required to pay refunds of between $3 and $4 million for transactions that we entered into with these entities for the period between October 2000 and June 2001. While the process at FERC is ongoing, FERC has indicated that we will have the ability to reduce the potential refund amount in order to recover outstanding receivables we are owed. FERC also has indicated that it will consider adjustments to the refund amount to the extent we can demonstrate that its refund methodology resulted in an overall revenue shortfall for our transactions in these markets during the refund period.

The situation with PGE and SCE has not had a material impact on our financial results. However, we cannot provide any assurance that the events in California will not have a material, adverse impact on our financial results, or that any legislative, regulatory, or other solution enacted in California will permit us to recover any past losses or will not have a negative effect on our business opportunities in California.

We are currently leasing and supervising the construction of the High Desert project, a 750 megawatt generating facility in California. The High Desert project uses an off-balance sheet financing structure through a special-purpose entity (SPE) that currently qualifies as an operating lease. The project is scheduled for completion in the summer of 2003. We signed a contract to sell all of the plant's output to the California Department of Water Resources on a unit contingent basis. The contract has a term of eight years and three months.

In February 2002, the FASB proposed a new accounting interpretation that potentially would impact the accounting for, but not the cash flows associated with, our High Desert operating lease and the related SPE. Under the proposed interpretation, we may be required to consolidate the SPE in our Consolidated Balance Sheets. We would have recorded approximately $221 million of development, construction, and capitalized financing costs as an asset and the related financial obligations as a liability in our Consolidated Balance Sheets had we consolidated this project at December 31, 2001.

We discuss our High Desert project in more detail in the *Capital Resources* section on page 43.

In February 2002, the California Department of Water Resources filed a claim with the FERC that all long-term contracts for power supply that the California Department of Water Resources entered into in the first quarter of 2001, which includes the contracts related to our High Desert project, were not just and reasonable. The California Department of Water Resources is requesting the FERC to terminate the contracts entirely or, at least, modify the prices to terms that the FERC considers just and reasonable. Currently, we are discussing the renegotiations of our contracts with the California Department of Water Resources. We cannot estimate the timing or impact of the FERC proceedings or the renegotiations of our contracts.

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.

Market Risks

The decline in both short-term and long-term market prices of electricity has had, and is expected to continue to have, a significant, negative impact on our financial results in certain regions in which we operate or expect to operate. In addition, significant uncertainties exist in the competitive energy marketplace.

We discuss our market risks in detail on page 44.

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 plant asset and higher operating costs, plus a profit, beginning at the time of replacement. Generally, rate increases improve our utility earnings because they allow us to collect more revenue. However, rate increases are normally granted based on historical data, and those increases may not always keep pace with increasing costs. Other parties may petition the Maryland PSC to decrease base rates.

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

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

Fuel Rate

Through June 30, 2000, we charged our electric customers separately for the fuel we used to generate electricity (nuclear fuel, coal, gas, or oil) and for the net cost of purchases and sales of electricity. We charged the actual cost of these items to the customer with no profit to us. If these fuel costs went up, the Maryland PSC generally 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 collected this accumulated difference from customers over the twelve-month period ended October 2001. 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 on page 39 and in Note 1 on page 58.

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).

On July 12, 2001, FERC provisionally granted RTO status to PJM and ordered it to engage in mediation with the New York ISO and the New England ISO to create a business plan to form one Northeast RTO, using PJM as a platform. After further hearings by FERC, it announced that it is re-evaluating its Order regarding a Northeast RTO. In the meantime, PJM is exploring opportunities to expand into other regions.

The creation of large RTOs could benefit our merchant energy business by allowing easier access to transmission and a uniform rate across various regions.

In addition, PJM is required to submit a filing by July 1, 2002 addressing implementation of a uniform transmission rate by January 1, 2003. A uniform rate could expose BGE to higher transmission rates.

BGE, jointly with other PJM transmission owners, requested rehearing and clarification from FERC on its July 12, 2001 order regarding certain incentive rates, interconnection procedures, and allocations of interconnection costs. FERC has not yet issued an order on this request.

Weather

Merchant Energy Business

Weather conditions in the different regions of North America influence the financial results of our merchant energy business. Weather conditions can affect the supply of and demand for electricity and fuels, and changes in energy supply and demand may impact the price of these energy commodities in both the spot market and the forward market. Typically, demand for electricity and its price are higher in the summer and the winter, when weather is more extreme. Similarly, the demand for and price of natural gas and oil are higher in the winter. However, all regions of North America typically do not experience extreme weather conditions at the same time. We discuss our market risk in detail on page 45.

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 on page 39.

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

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

We show the number of cooling and heating degree days in 2001 and 2000, 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.

	2001	2000	30-year Average
Cooling degree days	**787**	736	839
Percentage change from prior year	**6.9%**	(12.9)%	
Heating degree days	**4,514**	4,936	4,725
Percentage change from prior year	**(8.5)%**	7.7%	

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 11 on page 79 and in our most recent Annual Report on Form 10-K. Some of the information is about costs that may be material to our financial results.

Accounting Standards Adopted and Issued

We discuss recently adopted and issued accounting standards in Note 1 on page 63.

Results of Operations

In this section, we discuss our earnings and the factors affecting them. We begin with a general overview, then separately discuss net income for our operating segments. Changes in fixed charges and income taxes are discussed in the aggregate for all segments in the *Consolidated Nonoperating Income and Expenses* section on page 41.

Overview

Net Income

	2001	2000	1999
		(in millions)	
Net Income Before Special Costs Included in Operations:			
Merchant energy	**$291.2**	$213.6	$ 66.6
Regulated electric	**84.5**	106.5	270.0
Regulated gas	**38.3**	30.6	33.0
Other nonregulated	**3.2**	13.8	2.2
Net Income Before Special Costs Included in Operations	**417.2**	364.5	371.8
Special Costs Included in Operations:			
Contract termination related costs	**(139.6)**	–	–
Loss on sale of Guatemalan operations	**(28.1)**	–	–
Workforce reduction costs	**(64.1)**	(4.2)	–
Impairments of domestic power projects	**(30.5)**	–	(14.2)
Impairments of real estate, senior-living, and international investments	**(69.7)**	–	(10.3)
Reduction of financial investments	**(2.8)**	–	(16.0)
Deregulation transition cost	**–**	(15.0)	–
Hurricane Floyd	**–**	–	(4.9)
Net Income Before Extraordinary Item and Cumulative Effect of Change in Accounting Principle	**82.4**	345.3	326.4
Extraordinary Loss	**–**	–	(66.3)
Cumulative Effect of Change in Accounting Principle	**8.5**	–	–
Net Income	**$ 90.9**	$345.3	$260.1

Net income for the periods presented reflect a significant shift from the regulated electric business to the merchant energy business as a result of the transfer of BGE's electric generation assets to nonregulated subsidiaries on July 1, 2000. We discuss this in more detail in Note 5 on page 69.

2001

Our total net income for 2001 decreased $254.4 million, or $1.73 per share, compared to 2000 mostly because of the following special costs in operations:

- Our merchant energy business recorded expenses of $139.6 million after-tax, or $.87 per share, related to the termination of our power marketing operation's power business services agreement with Goldman Sachs.
- Our Latin American operation recognized a $28.1 million after-tax, or $.17 per share, loss on the sale of the Guatemalan power plant operations.
- We recorded costs of $64.1 million after-tax, or $.40 per share, associated with our corporate-wide workforce reduction program.
- Our merchant energy business recorded impairments that total $30.5 million after-tax, or $.19 per share, primarily due to the termination of certain planned development projects and due to a decline in value of an investment in a power project.
- Our other nonregulated businesses recorded $69.7 million after-tax, or $.43 per share, impairments of certain real estate projects, senior-living facilities, and international assets. This was a result of our decision to sell certain non-core assets and accelerate the exit strategies on other assets that we will continue to hold and own over the next several years, as well as an other than temporary decline in the value of our equity method Bolivian investment.
- Our financial investments business recorded a $2.8 million after-tax, or $.02 per share, reduction of its investment in an aircraft due to the decline in value of used airplanes as a result of the September 11, 2001 terrorist attacks and the general downturn in the aviation industry.

These decreases were partially offset by the following:

- Our merchant energy business recorded in 2000 an expense of $15.0 million after-tax, or $.10 per share, for a deregulation transition cost to Goldman Sachs.
- BGE recorded an expense of $4.2 million after-tax, or $.03 per share, for its employees that elected to participate in a targeted VSERP in 2000 that had a negative impact in that year.
- We recorded an $8.5 million after-tax, or $.05 per share, gain for the cumulative effect of adopting Statement of Financial Accounting Standard (SFAS) No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended, in the first quarter of 2001.
- Net income before special costs increased $.17 per share compared to 2000 as discussed in more detail below.

Net income before special costs was $417.2 million, or $2.60 per share, in 2001 compared to $364.5 million, or $2.43 per share, in 2000. Net income before special costs were higher compared to 2000 mostly because BGE recorded $75.0 million pre-tax, or approximately $.30 per share, of amortization expense for the reduction of our generating plants associated with the Restructuring Order in 2000 that had a negative impact in that year. In addition, we had higher earnings from our regulated gas business in 2001 mostly because of increases in the sharing mechanism under our gas cost adjustment clauses and the increase in our base rates. These increases were offset by the impact of a 6.5% annual electric residential rate reduction that was effective July 1, 2000, and decreases in earnings from our other nonregulated businesses.

Net income before special costs from our other nonregulated businesses decreased primarily due to declining equity values and lower gains on sales of equity securities in our financial investments business.

2000

Our 2000 total net income increased $85.2 million, or $.56 per share, compared to 1999 mostly because we recorded an extraordinary charge of $66.3 million after-tax, or $.44 per share, associated with the deregulation of the electric generation portion of our business in 1999. In addition, we recorded several special costs in 1999 that had a negative impact in that year as follows:

- Our regulated electric business recorded $4.9 million after-tax, or $.03 per share, of expenses related to Hurricane Floyd.
- Our generation operation recorded impairments of certain power projects of $14.2 million after-tax, or $.09 per share.
- Our Latin American operation recorded a $4.5 million after-tax, or $.03 per share, impairment of an investment in a power project.
- Our financial investments business recorded a $16.0 million after-tax, or $.11 per share, reduction of a financial investment.
- Our real estate and senior-living facilities business recorded a $5.8 million after-tax, or $.04 per share, impairment of certain senior-living facilities.

These were partially offset by the following special costs in operations recorded in 2000:

- $15.0 million after-tax deregulation transition cost in June 2000 to Goldman Sachs incurred by our power marketing operation to provide BGE's standard offer service requirements, and
- $4.2 million after-tax expense during the first and second quarters of 2000 for BGE employees that elected to participate in a targeted VSERP.

Net income before special costs was $364.5 million, or $2.43 per share, in 2000 compared to $371.8 million, or $2.48 per share, in 1999. Net income before special costs included in operations decreased 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 implementation of the deregulation of electric generation, starting July 1, 2000. These decreases were offset partially by higher earnings in our merchant energy and our other nonregulated businesses.

In 2000, net income from our merchant energy business before special costs increased compared to 1999 because of higher earnings in both our power marketing and generation operations.

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

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

Merchant Energy Business

Our merchant energy business is exposed to various market risks as discussed further on page 45.

We record the financial impacts of these market risks in earnings in different periods depending upon which portion of our merchant energy business they affect.

- We record changes in the value of contracts in our power marketing operation that are subject to mark-to-market accounting in earnings in the period in which the change occurs.
- Prior to the settlement of the anticipated transaction being hedged, we record changes in the value of contracts designated as cash flow hedges of our generation operations in other comprehensive income to the extent that the hedges are effective. We record the effective portion of hedges in earnings in the period the settlement of the hedged transaction occurs. We record the ineffective portion of such hedges, if any, in earnings in the period in which the change occurs.

Mark-to-market accounting requires us to make estimates and assumptions using judgment in determining the fair value of our contracts and in recording revenues from those contracts. We discuss the effects of mark-to-market accounting on our revenues in the *Mark-to-Market Energy Revenues* section on page 32. We discuss mark-to-market accounting and the accounting policies for the merchant energy business further in the *Critical Accounting Policies* section on page 22 and in Note 1 on page 58.

As discussed in the *Business Environment—Electric Competition* section on page 25, our 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 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 (July 1, 2000 to June 30, 2003) of the transition period. In August 2001, BGE entered into a contract with Constellation Power Source to provide 90% of the energy and capacity required for BGE to meet its standard offer service requirements for the final three years (July 1, 2003 to June 30, 2006) of the transition period.

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

Net Income

	2001	2000	1999
		(In millions)	
Revenues	**$1,765.5**	$1,025.7	$277.3
Operating expenses	**1,082.3**	586.8	151.5
Workforce reduction costs	**46.0**	–	–
Contract termination related costs	**224.8**	–	–
Impairment losses and other costs	**46.9**	–	21.4
Depreciation and amortization	**174.9**	83.6	7.5
Taxes other than income taxes	**49.4**	24.6	–
Income from Operations	**$ 141.2**	$ 330.7	$ 96.9
Net Income	**$ 93.1**	$ 198.6	$ 52.4
Net Income Before Special Costs Included in Operations	**$ 291.2**	$ 213.6	$ 66.6
Workforce reduction costs	**(28.0)**	–	–
Contract termination related costs	**(139.6)**	–	–
Deregulation transition cost	**–**	(15.0)	–
Impairment of power projects	**(30.5)**	–	(14.2)
Net Income	**$ 93.1**	$ 198.6	$ 52.4

Above amounts include intercompany transactions eliminated in our Consolidated Financial Statements. Note 3 on page 67 provides a reconciliation of operating results by segment to our Consolidated Financial Statements.

Revenues

Merchant energy revenues increased $739.8 million during 2001 compared to 2000 mostly due to:

- supplying BGE's standard offer service requirements for a full year in 2001 as compared to six months in 2000,
- higher revenues from other sales of generation, including new peaking facilities and Nine Mile Point, and
- higher mark-to-market energy revenues.

Merchant energy revenues increased $748.4 million during 2000 compared to 1999 mostly due to:

- providing BGE's standard offer service requirements effective July 1, 2000, and
- higher revenues from our generation and power marketing operations.

We discuss the revenues from our generation and power marketing operations below.

Revenues from BGE Standard Offer Service

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

Merchant energy revenues increased $691.0 million, including $110.0 million of CTC and decommissioning revenues, in 2000 compared to 1999 related to providing BGE's standard offer service requirements effective July 1, 2000.

Other Generation Revenues

Other generation revenues increased $142.2 million in 2001 as compared to 2000 primarily due to the construction of new power plants and the acquisition of Nine Mile Point, as well as additional sales from our existing facilities. Revenues from peaking facilities that commenced operations during mid-summer 2001 totaled $83.6 million, and revenues from Nine Mile Point, which we acquired in November 2001, totaled $55.2 million.

Additionally, sales of power from our Baltimore plants in excess of that required to serve BGE's standard offer service requirements increased $51.2 million. Our generation operation also recognized a $9.5 million gain on the sale of a project under development in the PJM region in March 2001.

These increases were partially offset by the following:

- Revenues associated with the California power purchase agreements decreased $22.0 million. We discuss the California power purchase agreements on page 32.
- In April 2000, our generation operation terminated an operating arrangement and sold certain subsidiaries of Constellation Operating Services Inc. (COSI) to Orion. COSI ended its exclusive arrangement with Orion to operate Orion's facilities, and Orion purchased from COSI the four subsidiary companies formed to operate power plants owned by Orion. Our generation operation recognized a $13.3 million gain on this sale in 2000 which had a positive impact on that year, and we also had lower revenues during 2001 compared to 2000 due to the sale of these subsidiaries.

Other generation revenues increased $47.6 million during 2000 compared to 1999 mostly because of the following:

- sales of power from our Baltimore plants in excess of that required to serve BGE's standard offer requirements totaled $40.7 million, and
- our generation operation recognized a $13.3 million gain on the termination of an operating arrangement and the sale of certain subsidiaries of COSI as discussed above.

These increases were partially offset by a decrease of $14.9 million in revenues associated with our California power purchase agreements. We discuss the California power purchase agreements on page 32.

The significant decline in the long-term prices of electricity since early 2001 has affected, and may continue to affect, our facilities that have not entered into contracts for the sale of their generation.

Under the Restructuring Order, larger industrial customers have available standard offer service until June 30, 2002. Beginning in July 2002, approximately 1,000 megawatts of industrial customer load will move from BGE's standard offer service to market-based rates. As a result, our merchant energy business will have an increasing amount of generating capacity that will be sold at wholesale market rates and thus be subject to future changes in wholesale electricity prices. Refer to the *Business Environment* section on page 25 for further discussion.

California Power Purchase Agreements

Our generation operation has $296.4 million invested in 14 operating projects of which our ownership percentage represents 146 megawatts of electricity that are sold in California to PGE and SCE under power purchase agreements called SO4 agreements.

Under these agreements, the projects supply electricity to these utilities at variable rates. Revenues from these projects were $22.1 million in 2001 compared to $44.1 million in 2000. Revenues decreased because of lower power prices in California during the second half of 2001. While energy rates were higher during the first half of 2001, the higher rates were offset by reserves established for our exposure in California during that period.

As previously discussed in the *Business Environment—Other States* section on page 26, the projects entered into agreements with PGE and SCE that provide for five-year fixed-price payments averaging $53.70 per megawatt-hour plus the stated capacity payments in the original SO4 contracts. We expect the revenues from these projects to be lower in 2002 compared to 2001.

We also describe these projects in Note 11 on page 83.

Mark-to-Market Energy Revenues

Mark-to-market energy revenues include net gains and losses from Constellation Power Source origination and risk management activities for which the mark-to-market method of accounting is required by Emerging Issues Task Force Issue 98-10, *Accounting for Contracts Involved in Energy Trading and Risk Management Activities.* We discuss the mark-to-market method of accounting and Constellation Power Source's activities in more detail in the *Critical Accounting Policies* section on page 22 and in Note 1 on page 58.

As a result of the nature of its operations and the use of mark-to-market accounting for certain activities, Constellation Power Source's revenues and earnings will fluctuate. We cannot predict these fluctuations, but the impact on our revenues and earnings could be material. We discuss our market risk in more detail on page 44. The primary factors that cause fluctuations in our revenues and earnings are:

- the number, size, and profitability of new transactions,
- the magnitude and volatility of changes in commodity prices and interest rates, and
- the number and size of our open commodity and derivative positions.

Mark-to-market energy revenues were as follows:

	2001	2000	1999
		(In millions)	
New origination transactions	**$227.0**	$158.8	$141.5
Risk management activities			
Realized	**19.7**	(57.0)	22.2
Unrealized	**(70.9)**	49.7	(16.0)
Total risk management activities	**(51.2)**	(7.3)	6.2
Total	**$175.8**	$151.5	$147.7

Revenues from new origination transactions represent the initial unrealized fair value of new wholesale energy transactions at the time of contract execution. Risk management revenues represent both realized and unrealized gains and losses from changes in the value of our entire portfolio. We discuss the changes in origination and risk management revenues below.

Constellation Power Source's mark-to-market revenues are influenced by our focus on serving the full electric energy and capacity requirements of electric utility customers. Providing utilities' full energy and capacity requirements requires greater ownership of or contractual access to power generating facilities, as opposed to merely standard products obtainable in liquid trading markets.

In order to enable us to serve such customers, during 2000 and 2001, we obtained access to physical power by entering into a portfolio of tolling arrangements and other physical delivery energy contracts. Tolling arrangements are contracts which provide us the right, but not the obligation, to purchase power at a price linked to the variable cost of production, including fuel. This inventory of energy supply somewhat exceeded the energy demands from existing transactions and provides resources to enable us to close additional transactions.

The relationship of the realized portion of revenue to total mark-to-market energy revenue in the table above reflects the nature of the origination transactions which Constellation Power Source has executed. A significant portion of these contracts provided for Constellation Power Source to serve customers' energy requirements at fixed prices that were lower in the early years of the contracts but that are expected to provide increased margins and cash flows over the remaining terms of the contracts. We discuss the settlement terms of our contracts on the next page.

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

Mark-to-market energy revenues increased $3.8 million during 2000 compared to 1999 due to increased origination revenue, which was offset partially by net losses from risk management activities. The increase in origination revenue reflects new transaction volumes, primarily in New England, the Mid-Atlantic, and Texas. The net losses from risk management activities resulted from realized losses in serving the initial year of long-term, fixed-price energy sales contracts as described above, substantially offset by unrealized gains on portions of the portfolio which benefited from the increases in future power prices and price volatility during 2000.

Constellation Power Source's mark-to-market energy assets and liabilities are comprised of a combination of derivative and non-derivative contracts. While some of these contracts represent commodities or instruments for which prices are available from external sources, other commodities and certain contracts are not actively traded and are valued using other pricing sources and modeling techniques to determine expected future market prices, contract quantities, or both.

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

At December 31,	2001	2000
	(In millions)	
Current Assets	**$ 398.4**	$ 453.1
Noncurrent Assets	**1,819.8**	2,069.3
Total Assets	**2,218.2**	2,522.4
Current Liabilities	**323.3**	358.2
Noncurrent Liabilities	**1,476.5**	1,636.3
Total Liabilities	**1,799.8**	1,994.5
Net mark-to-market energy asset	**$ 418.4**	$ 527.9

Following are the primary sources of the change in net mark-to-market energy asset during 2001:

Change in Net Mark-to-Market Energy Asset

		(In millions)
Fair value at December 31, 2000		$527.9
Changes in fair value recorded as revenues		
New origination transactions	$227.0	
Unrealized risk management revenues:		
Contracts settled	(19.7)	
Changes in valuation techniques	4.5	
Unrealized changes in fair value	(55.7)	
Total unrealized risk management revenues	$ (70.9)	
Total changes in fair value recorded as revenues		156.1
Changes in fair value recorded as operating expenses		(15.0)
Net change in premiums on options		(242.2)
Other changes in fair value		(8.4)
Fair value at December 31, 2001		$418.4

New origination transactions represent the initial unrealized fair value at the time these contracts are executed. Changes in valuation techniques represent improvements in the models used to value our portfolio to reflect more accurately the economic value of our contracts. Unrealized changes in fair value represents the change in value of our unrealized mark-to-market energy net asset due to changes in commodity prices, the volatility of options on commodities, the time value of options, and net changes in valuation allowances. Changes in fair value recorded as operating expenses represent accruals for future incremental expenses in connection with servicing origination transactions. While these accruals are reductions in the fair value of the net mark-to-market energy asset, they are recorded in the income statement as expenses rather than revenue. The net change in premiums on options reflects a net increase in options sold during 2001. We record premiums on options purchased as an increase in the net mark-to-market energy asset and premiums on options sold as a decrease in the net mark-to-market energy asset. Prior to 2001, we had entered into purchased option and energy tolling contracts in connection with serving our energy sales contracts. The option and tolling contracts, by their nature, exposed us to changes in the volatility of energy prices. During 2001, we sold options to reduce our exposure to option volatility.

The settlement term of the net mark-to-market energy asset and sources of fair value as of December 31, 2001 are as follows:

	Settlement Term								
	2002	2003	2004	2005	2006	2007	2008–2009	Thereafter	Total Fair Value
					(In millions)				
Prices provided by external sources	$67.0	$10.8	$25.8	$41.8	$26.8	$ (0.7)	$ 4.0	$ 0.4	$175.9
Prices based on models	8.2	25.9	(2.4)	47.9	48.1	50.2	84.4	(19.8)	242.5
Total net mark-to-market energy asset	$75.2	$36.7	$23.4	$89.7	$74.9	$49.5	$88.4	$(19.4)	$418.4

Constellation Power Source manages its risk on a portfolio basis based upon the delivery period of its contracts and the individual components of the risks within each contract. Accordingly, we record and manage the energy purchase and sale obligations under our contracts in separate components based upon the commodity (e.g., electricity or gas), the product (e.g., electricity for delivery during peak or off-peak hours), the delivery location (e.g., by region), the risk profile (e.g., forward or option), and the delivery period (e.g., by month and year). Consistent with our risk management practices, we have presented the information in the table on the previous page based upon the ability to obtain reliable prices for components of the risks in our contracts from external sources rather than on a contract-by-contract basis. Thus, the portion of long-term contracts that is valued using external price sources is classified in the same caption as other shorter-term transactions that settle in the same period. This presentation is consistent with how we manage our risk, and we believe it provides the best indication of the basis for the valuation of our portfolio. Since we manage our risk on a portfolio basis rather than contract-by-contract, it is not practicable to determine separately the portion of long-term contracts that is included in each valuation category. We describe the commodities, products, and delivery periods included in each valuation category in detail below.

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

- forward purchases and sales of electricity during peak hours for delivery terms of four to six years, depending upon the region,
- forward purchases and sales of electricity during off-peak hours for delivery terms of two to four years, depending upon the region,
- options for the purchase and sale of electricity for delivery terms of up to two years,
- forward purchases and sales of electric capacity for delivery terms of up to two years,
- forward purchases and sales of natural gas and oil for delivery terms of up to four years, and
- options for the purchase and sale of natural gas and oil for delivery terms of up to two years.

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

Modeling techniques include estimating the present value of cash flows based upon underlying contractual terms and incorporate, where appropriate, option pricing models and statistical simulation procedures. Inputs to the models include observable market prices, estimated market prices in the absence of quoted market prices, the risk-free market discount rate, volatility factors, estimated correlation of energy commodity prices, contractural volumes, and estimated volumes for requirements contracts. Additionally, we incorporate counterparty-specific credit quality and factors for market price uncertainty and other risks in our valuation. The inputs and factors used to determine fair value reflect management's best estimates.

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

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

The fair values in the table represent expected future cash flows based on the level of forward prices and volatility factors as of December 31, 2001. These amounts do not represent the contractual maturities and could change significantly as a result of future changes in these factors. Additionally, because the depth and liquidity of the power markets varies substantially between regions and time periods, the prices used to determine fair value could be affected significantly by the volume of transactions executed. Constellation Power Source's management uses its best estimates to determine the fair value of commodity and derivative contracts it holds and sells. These estimates consider various factors including closing exchange and over-the-counter price quotations, time value, volatility factors, and credit exposure. However, it is possible that future market prices could vary from those used in recording mark-to-market energy assets and liabilities, and such variations could be material.

Operating Expenses
Merchant energy operating expenses increased $495.5 million during 2001 compared to 2000 mostly because of the following:

- Fuel and purchased energy costs increased $291.5 million and operations and maintenance costs increased $236.7 million. These increases reflect a full year's operation of the generation plants that were transferred from BGE effective July 1, 2000, as well as, the added operations of the new peaking facilities and Nine Mile Point. The fuel cost increase also reflects higher fuel prices for generating electricity. Coal prices increased during 2001, and we expect to incur additional costs in the future to operate our coal generating facilities due to higher prices.
- Power marketing operating expenses associated with the growth of the operation increased $31.6 million.

These increased costs were partially offset by lower fees earned by Goldman Sachs at our power marketing operation due to the termination of the power business services agreement in October 2001. The Goldman Sachs fees were $28.9 million in 2001, $81.3 million in 2000, and $31.8 million in 1999. The amount of fees for 2000 includes the $24.0 million, or $.10 per share, deregulation transition cost as discussed below. These fees will not be incurred in the future due to the termination of the power business services agreement with Goldman Sachs. In addition, COSI had lower operating expenses due to the sale of certain subsidiaries to Orion, as previously discussed.

Operating expenses increased $435.3 million in 2000 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 associated with the generation plants that were transferred from BGE effective July 1, 2000,
- an increase in Goldman Sachs fees of $49.5 million, including the $24.0 million deregulation transition cost incurred by our power marketing operation to provide BGE's standard offer service requirements, and
- a $6.2 million increase in power marketing operating expenses associated with the growth of the operation.

In light of the events of September 11, 2001, we have taken additional security measures at our nuclear facilities. While we anticipate continuing to incur additional security related costs at our nuclear facilities, we do not expect that these costs will be material. However, the Nuclear Regulatory Commission (NRC) currently is evaluating additional security measures that may be required at nuclear facilities. At this time, we cannot determine the impact on our financial results of any additional security measures that may be required by the NRC.

Extended Nuclear Outages
Our merchant energy business will experience extended outages at Calvert Cliffs to replace the steam generators during the 2002 refueling outage for Unit 1 and during the 2003 refueling outage for Unit 2. As a result of the extended outages, we expect lower annual revenues and higher annual operating costs for each extended outage.

Workforce Reduction Costs, Contract Termination Related Costs, and Impairment Losses and Other Costs
As previously discussed in the *Events of 2001* section on page 22, our merchant energy business recognized the following:

- $46.0 million, or $.17 per share, of expenses associated with our workforce reduction efforts,
- $224.8 million, or $.87 per share, of expenses related to the termination of the power business services agreement with Goldman Sachs,
- a $40.8 million, or $.16 per share, impairment of certain planned development projects that were terminated, and
- a $6.1 million, or $.03 per share, loss on the impairment of a power project.

As a result of our workforce reduction efforts, our merchant energy business expects to generate annual savings of approximately $24 million.

In 1999, our generation operation recorded a $21.4 million, or $.09 per share, write-off of two geothermal power projects, which had a negative impact in that year.

We discuss these workforce reduction costs, contract termination related costs, and impairment losses and other costs further in Note 2 on page 64.

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

Merchant energy depreciation and amortization expense increased $76.1 million in 2000 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.

Taxes Other than Income Taxes
Merchant energy taxes other than income taxes increased in 2001 and 2000 compared to their respective prior year mostly because of taxes other than income taxes associated with the generation plants that were transferred from BGE effective July 1, 2000.

Regulated Electric Business

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

Net Income

	2001	2000	1999
		(In millions)	
Electric revenues	**$2,040.0**	$2,135.2	$2,260.0
Electric fuel and purchased energy	**1,192.8**	870.7	487.7
Operations and maintenance	**258.7**	447.2	629.6
Workforce reduction costs	**55.7**	7.0	–
Depreciation and amortization	**173.3**	319.9	376.4
Taxes other than income taxes	**139.5**	157.8	188.9
Income from Operations	**$ 220.0**	$ 332.6	$ 577.4
Net Income Before Extraordinary Item	**$ 50.9**	$ 102.3	$ 265.1
Extraordinary loss	**–**	–	(66.3)
Net Income	**$ 50.9**	$ 102.3	$ 198.8
Net Income Before Special Costs Included in Operations and Extraordinary Item	**$ 84.5**	$ 106.5	$ 270.0
Workforce reduction costs	**(33.6)**	(4.2)	–
Hurricane Floyd	**–**	–	(4.9)
Extraordinary loss	**–**	–	(66.3)
Net Income	**$ 50.9**	$ 102.3	$ 198.8

Above amounts include intercompany transactions eliminated in our Consolidated Financial Statements. Note 3 on page 67 provides a reconciliation of operating results by segment to our Consolidated Financial Statements.

Electric Revenues

The changes in electric revenues in 2001 and 2000 compared to the respective prior year were caused by:

	2001	2000
	(In millions)	
Electric system sales volumes	**$ 2.8**	$ 40.9
Rates	**(79.3)**	(119.9)
Fuel rate surcharge	**30.5**	12.6
Total change in electric revenues from electric system sales	**(46.0)**	(66.4)
Interchange and other sales	**(53.8)**	(58.3)
Other	**4.6**	(0.1)
Total change in electric revenues	**$(95.2)**	$(124.8)

Electric System Sales Volumes

"Electric system sales volumes" are sales to customers in BGE's service territory at rates set by the Maryland PSC. As part of the Restructuring Order, the rates received from customers under the standard offer service increase over the transition period as discussed further in the *Business Environment—Electric Competition* section beginning on page 25. 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 2001 and 2000 compared to the respective prior year were:

	2001	2000
Residential	**0.3%**	2.9%
Commercial	**0.7**	3.5
Industrial	**(0.7)**	2.9

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

In 2000, we sold more electricity to residential customers compared to 1999 due to 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 in 2000 as a result of a 1999 shut down for a planned upgrade to their facilities that temporarily reduced their electricity consumption in that year.

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

Rate revenues decreased in 2001 compared to 2000 mostly due to:

- the 6.5% annual residential rate reduction of $17.6 million recorded through June 30, 2001, and
- $74.4 million of revenues that were transferred to the merchant energy business discussed above.

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

Rate revenues decreased in 2000 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 merchant energy business. This was offset partially by higher fuel rate revenues during the first half of 2000.

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 a RTO/ISO that also operates a regional power pool with members that include many wholesale market participants, as well as BGE and other utility companies. Prior to the implementation of customer choice, BGE sold energy to PJM members and to others after it had satisfied the demand for electricity in its own system.

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

Electric Fuel and Purchased Energy Expenses

	2001	2000	1999
		(In millions)	
Actual costs	**$1,150.5**	$868.0	$558.0
Net recovery (deferral) of costs under electric fuel rate clause	**42.3**	2.7	(70.3)
Total electric fuel and purchased energy expenses	**$1,192.8**	$870.7	$487.7

Actual Costs

As discussed in the *Business Environment—Electric Competition* section on page 25, effective July 1, 2000, BGE transferred its generating assets to, and began purchasing substantially all of the energy and capacity required to provide electricity to standard offer service customers from, the merchant energy business.

Our actual costs of fuel and purchased energy increased in 2001 compared to 2000 mostly because of the deregulation of electric generation. The higher amount BGE paid for purchased energy from our merchant energy business is offset by the absence of $206.4 million in 2001 and $191.6 million in 2000 in fuel costs, and lower operations and maintenance, depreciation, taxes, and other costs at BGE as a result of no longer owning and operating the transferred electric generation plants.

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

Electric 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 collected this accumulated difference from customers over the twelve-month period ended October 2001.

Electric Operations and Maintenance Expenses

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

Regulated electric operations and maintenance expenses decreased $182.4 million during 2000 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 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.

Workforce Reduction Costs

In 2001, BGE's electric business recognized $55.7 million, or $.21 per share, of expenses associated with our workforce reduction efforts. As a result of our workforce reduction efforts, our regulated electric business expects to generate annual savings of approximately $36 million. In 2000, BGE's electric business recognized $7.0 million, or $.03 per share, of expenses for employees that elected to participate in a targeted VSERP that had a negative impact in that year. We discuss these programs further in Note 2 on page 64.

Electric Depreciation and Amortization Expense

Regulated electric depreciation and amortization expense decreased $146.6 million during 2001 compared to 2000 mostly due to:

- the absence of $75.0 million of amortization expense recorded in 2000 associated with the $150 million reduction of our generating plants provided for in the Restructuring Order, and
- $75.1 million of expenses associated with the transfer of the generation assets to the merchant energy business effective July 1, 2000.

Regulated electric depreciation and amortization expense decreased $56.5 million during 2000 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 and higher amortization associated with regulatory assets.

Electric Taxes Other Than Income Taxes

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

Regulated electric taxes other than income taxes decreased $31.1 million during 2000 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 merchant energy business effective July 1, 2000, and
- comprehensive changes to the tax laws.

The comprehensive tax law changes are discussed further in Note 5 on page 69.

Regulated Gas Business
Net Income

	2001	2000	1999
		(In millions)	
Gas revenues	**$680.7**	$611.6	$488.1
Gas purchased for resale	**401.3**	350.6	233.8
Operations and maintenance	**104.3**	100.6	97.7
Workforce reduction costs	**1.3**	–	–
Depreciation and amortization	**47.7**	46.2	44.9
Taxes other than income taxes	**34.3**	34.8	34.5
Income from Operations	**$ 91.8**	$ 79.4	$ 77.2
Net Income	**$ 37.5**	$ 30.6	$ 33.0
Net Income Before Special Costs Included in Operations	**$ 38.3**	$ 30.6	$ 33.0
Workforce reduction costs	**(0.8)**	–	–
Net Income	**$ 37.5**	$ 30.6	$ 33.0

Above amounts include intercompany transactions eliminated in our Consolidated Financial Statements. Note 3 on page 67 provides a reconciliation of operating results by segment to our Consolidated Financial Statements.

Net income from our regulated gas business increased during 2001 compared to 2000 mostly due to the sharing mechanism under our gas cost adjustment clauses and the increase in our base rates.

Net income from the regulated gas business decreased during 2000 compared to 1999 mostly due to a slight increase in operations and maintenance and depreciation expenses partially offset by an increase in our base rates.

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

Gas Revenues

The changes in gas revenues in 2001 and 2000 compared to the respective prior year were caused by:

	2001	2000
	(In millions)	
Gas system sales volumes	**$(3.4)**	$ 34.5
Base rates	**3.3**	2.7
Weather normalization	**11.9**	(26.7)
Gas cost adjustments	**43.6**	54.7
Total change in gas revenues from gas system sales	**55.4**	65.2
Off-system sales	**12.5**	58.1
Other	**1.2**	0.2
Total change in gas revenues	**$69.1**	$123.5

Gas System Sales Volumes

The percentage changes in our gas system sales volumes, by type of customer, in 2001 and 2000 compared to the respective prior year were:

	2001	2000
Residential	**(7.8)%**	13.0%
Commercial	**3.5**	12.8
Industrial	**(25.2)**	(2.1)

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

We sold more gas to residential and commercial customers during 2000 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 partially offset by an increased number of customers.

Base Rates

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

Weather Normalization

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

Gas Cost Adjustments

We charge our gas customers for the natural gas they purchase from us using gas cost adjustment clauses set by the Maryland PSC as described in Note 1 on page 58. However, under market-based rates, our actual cost of gas is compared to a market index (a measure of the market price of gas in a given period). The difference between our actual cost and the market index is shared equally between shareholders and customers. The shareholders' portion increased $3.6 million during 2001 compared to 2000. Effective November 2001, the Maryland PSC approved an order that modifies certain provisions of the market-based rates incentive mechanism. These provisions require that BGE secure fixed-price contracts for at least 10%, but not more than 20%, of forecasted system supply requirements for the November through March period. These fixed price contracts are not subject to sharing under the market-based rates incentive mechanism. We do not expect these changes to have a material impact on our financial results.

Delivery service customers, 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.

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

Gas cost adjustment revenues increased during 2000 compared to 1999 mostly because we sold more gas at a higher price. 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).

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

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

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.

Our gas costs increased during 2001 compared to 2000 mostly because gas we purchased was at a higher price partially offset by less gas purchased for both system and off-system sales. Our gas costs increased during 2000 compared to 1999 mostly because we bought more gas for both system and off-system sales, and all of the gas purchased was at a higher price due to the significant increase in natural gas prices during 2000.

Other Gas Operating Expenses

Other gas operating expenses were about the same during 2001 and 2000 compared to the respective prior year.

As a result of our workforce reduction efforts, our regulated gas business expects to generate annual savings of approximately $12 million. The cost of these programs was deferred as a regulatory asset. See Note 6 on page 71.

Other Nonregulated Businesses

Net Income

	2001	2000	1999
		(In millions)	
Revenues	**$602.1**	$713.3	$848.4
Operating expenses	**510.7**	588.8	771.5
Workforce reduction costs	**2.7**	–	–
Impairment losses and other costs	**155.2**	–	42.9
Depreciation and amortization	**23.2**	20.3	21.0
Taxes other than income taxes	**3.4**	4.3	3.9
(Loss) Income from Operations	**$ (93.1)**	$ 99.9	$ 9.1
Net (Loss) Income Before Cumulative Effect of Change in Accounting Principle	**$ (99.1)**	$ 13.8	$ (24.1)
Cumulative Effect of Change in Accounting Principle	**8.5**	–	–
Net (Loss) Income	**$ (90.6)**	$ 13.8	$ (24.1)
Net Income Before Special Costs Included in Operations	**$ 3.2**	$ 13.8	$ 2.2
Workforce reduction costs	**(1.7)**	–	–
Loss on sale of Guatemalan operations	**(28.1)**	–	–
Impairment of real estate, senior-living, and international investments	**(69.7)**	–	(10.3)
Reduction of financial investment	**(2.8)**	–	(16.0)
Net (Loss) Income Before Cumulative Effect of Change in Accounting Principle	**(99.1)**	13.8	(24.1)
Cumulative Effect of Change in Accounting Principle	**8.5**	–	–
Net (Loss) Income	**$ (90.6)**	$ 13.8	$ (24.1)

Above amounts include intercompany transactions eliminated in our Consolidated Financial Statements. Note 3 on page 67 provides a reconciliation of operating results by segment to our Consolidated Financial Statements.

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

- Our Latin American operations recorded a loss of $28.1 million after-tax, or $.17 per share, on the sale of our Guatemalan operations.
- We recorded $69.7 million after-tax, or $.43 per share, in impairments of certain non-core assets. We decided to sell six real estate projects without further development and all of our senior-living facilities in 2002 and accelerate the exit strategies for two other real estate projects that we will continue to hold and own over the next several years. We also decided to accelerate the exit strategy for the investment in a distribution company in Panama and expect to complete the sale by mid-to-late 2003. Finally, there was an other than temporary decline in value in our equity method Bolivian investment due to a deterioration in our investment's position in the Bolivian capacity market.
- Our financial investments business recorded a $2.8 million after-tax, or $.02 per share, reduction of its investment in an aircraft due to the decline in value of used airplanes as a result of the September 11, 2001 terrorist attacks and the general downturn in the aviation industry.

We discuss these special costs further in Note 2 on page 65.

In addition, our financial investments business had lower earnings due to declining equity values and lower gains on sales of equity securities, partially offset by an $8.5 million after-tax, or $.05 per share, gain for the cumulative effect of adopting SFAS No. 133 in the first quarter of 2001. The gains on sales of securities include a $9.0 million after-tax gain on the sale of one million shares of the Orion investment in 2001 and a $9.5 million after-tax gain on the sale of two million shares of our Orion investment in 2000.

Net income from our other nonregulated businesses increased during 2000 compared to 1999 mostly because of better market performance of certain of our financial investments including the sale of certain equity securities. In addition, in 1999, we reduced the values of a financial investment, our investment in an electric generating company in Bolivia, and certain senior-living facilities, which had negative impacts in that year, as discussed in more detail in Note 2 on page 66. These increases were offset partially by lower earnings from our Latin American operation primarily due to increased operating expenses in Guatemala in 2000.

As previously discussed in the *Events of 2001* section, we decided to sell certain non-core assets and accelerate the exit strategies on other assets that we will continue to hold and own over the next several years. These assets include approximately 1,300 acres of land holdings in various stages of development located in seven sites in the central Maryland region, an operating waste water treatment plant located in Anne Arundel County, Maryland, all of our 18 senior-living facilities, and certain international power projects. While our intent is to dispose of these assets, market conditions and other events beyond our control may affect the actual sale of these assets. In addition, a future decline in the fair value of these assets could result in additional losses.

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

Consolidated Nonoperating Income and Expenses

Fixed Charges

Total fixed charges decreased $32.6 million during 2001 compared to 2000 mostly because of lower interest rates and higher capitalized interest associated with our construction of new generating facilities. These decreases were offset partially by a higher average level of debt outstanding.

Fixed charges increased $16.4 million during 2000 compared to 1999 mostly because we had more debt outstanding.

Income Taxes

The differences in income taxes result from a combination of the changes in income and the effective tax rate. We include an analysis of the changes in the effective tax rate in our Consolidated Statements of Income Taxes on page 56.

Financial Condition

Cash Flows

Cash provided by operations was $573.3 million in 2001 compared to $850.9 million in 2000 and $679.0 million in 1999.

Cash used in investing activities was $1,472.7 million in 2001 compared to $1,106.5 million in 2000 and $615.1 million in 1999. The increase in 2001 compared to 2000 was mostly due to increased purchases of property, plant and equipment and other capital expenditures including $382.7 million relating to the net cash paid for the acquisition of Nine Mile Point. The increase in 2000 compared to 1999 was mostly due to substantial increases in our merchant energy capital expenditures to support our construction program.

Cash provided by financing activities was $789.1 million in 2001 compared to $345.6 million in 2000 and cash used in financing activities of $144.9 million in 1999. The increase in 2001 compared to 2000 was mostly due to increased proceeds from the issuance of common stock, an increase in proceeds from the net issuance of short-term borrowings, and a $130.0 million decrease in common stock dividends paid. These items were partially offset by the issuance of less long-term debt and higher repayments of our long-term debt. The increase in 2000 compared to 1999 was 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.

Security Ratings

Independent credit-rating agencies rate Constellation Energy's and BGE's fixed-income securities. The ratings indicate the agencies' assessment of each company's ability to pay interest, distributions, dividends, and principal on these securities. These ratings affect how much it will cost each company to sell these securities. The better the rating, the lower the cost of the securities to each company when they sell them. The factors that credit rating agencies consider in establishing Constellation Energy's and BGE's credit ratings include cash flows, liquidity, and the amount of debt as a component of total capitalization.

All three rating agencies recently completed reviews of Constellation Energy's and BGE's ratings. FitchRatings affirmed its ratings of Constellation Energy. Standard & Poors Rating Group downgraded Constellation Energy's commercial paper from A-1 to A-2 and senior unsecured debt from A- to BBB+. In addition, Moody's Investors Service downgraded Constellation Energy's commercial paper from P-1 to P-2 and senior unsecured debt from A3 to Baa1. All Constellation Energy ratings have stable outlooks.

Moody's Investors Service and FitchRatings recently affirmed the ratings of BGE. Standard & Poors Rating Group downgraded BGE commercial paper from A-1 to A-2, senior unsecured debt from A to BBB+, mortgage bonds from AA- to A, and Trust Originated Preferred Securities and Preference Stock from A- to BBB. All BGE ratings have stable outlooks.

At the date of this report, our credit ratings were as follows:

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

Available Sources of Funding

As previously discussed in the *Events of 2001* section, we decided to sell certain non-core assets to focus on our core strategies. We expect to use the proceeds from these sales to reduce our debt and fund our merchant energy business. We continuously monitor our liquidity requirements and believe that our facilities and access to the capital markets provide sufficient liquidity to meet our business requirements. We discuss our available sources of funding in more detail on the next page.

Constellation Energy

Constellation Energy has a commercial paper program where it can issue short-term notes to fund its subsidiaries. To support its commercial paper program, Constellation Energy maintains two 364-day revolving credit agreements totaling $2.9 billion maturing in June 2002, as well as a $188.5 million multi-year revolving credit facility. Two of these facilities can also issue letters of credit. As of December 31, 2001, Constellation Energy had $246 million in outstanding letters of credit and $955 million of outstanding commercial paper which results in approximately $1.8 billion of unused credit facilities. Constellation Energy also has access to interim lines of credit as required from time to time to support its outstanding commercial paper. We expect to refinance the majority of our outstanding short-term debt during the first half of 2002 with long-term debt.

BGE

BGE maintains $168.0 million in annual committed bank lines of credit and has $75.0 million in bank revolving credit agreements to support the commercial paper program. As of December 31, 2001, BGE had no outstanding commercial paper, which results in $243.0 million in unused credit facilities. BGE also has access to interim lines of credit as required from time to time to support its outstanding commercial paper and maintains a program to sell receivables up to $25 million.

Other Nonregulated Businesses

BGE Home Products & Services maintains a program to sell receivables up to $50 million. 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 remaining real estate projects and other investments, additional cash may be obtained by selling them. Our ability to sell or liquidate assets will depend on market conditions, and we cannot give assurances that these sales or liquidations could be made.

Capital Resources

Our business requires a great deal of capital. Our actual consolidated capital requirements for the years 1999 through 2001, along with the estimated annual amounts for the years 2002 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 2002 through 2003 include estimates of spending for existing and anticipated projects. We continuously review and modify those estimates.

Actual requirements may vary from the estimates included in the table below because of a number of factors including:

- regulation, legislation, and competition,
- BGE load requirements,
- environmental protection standards,
- the type and number of projects selected for construction or acquisition,
- the effect of market conditions on those projects,
- the cost and availability of capital, and
- the availability of cash from operations.

Our estimates are also subject to additional factors. Please see the *Forward Looking Statements* section on page 17.

Effective July 1, 2000, we transferred all of BGE's generation assets 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 merchant energy business.

	1999	2000	2001	2002	2003
			(In millions)		
Nonregulated Capital Requirements:					
Merchant Energy					
Construction program	$ 86	$ 537	$ 697	$152	$ –
Steam generators	–	21	53	91	65
Nine Mile Point acquisition	–	–	771	–	–
Environmental controls	–	45	89	69	16
Continuing requirements (including nuclear fuel)	77	96*	205	243	199
Total Merchant Energy capital requirements	163	699	1,815	555	280
Other Nonregulated capital requirements	115	131	35	39	34
Total Nonregulated capital requirements	278	830	1,850	594	314
Utility Capital Requirements:					
Regulated electric					
Generation (including nuclear fuel)	117	73	–	–	–
Steam generators	34	13	–	–	–
Environmental controls	31	17	–	–	–
Transmission and distribution	185	187	180	174	174
Total regulated electric	367	290	180	174	174
Regulated gas	69	60	59	56	56
Total Utility capital requirements	436	350	239	230	230
Total capital requirements	$714	$1,180	$2,089	$824	$544

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

Capital Requirements

Merchant Energy Business

Our merchant energy business will require additional funding for constructing planned power projects and growing its power marketing operation. These capital requirements include:

- Construction expenditures for approximately 2,900 megawatts of natural gas-fired peaking and combined cycle production facilities in various regions of North America under construction.
- Cost for replacing the steam generators at Calvert Cliffs. In March 2000, we received a license extension from the NRC that extends Calvert Cliffs' operating licenses to 2034 for Unit 1 and 2036 for Unit 2. Replacement of the steam generators will allow us to operate these units through our operating license periods. 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.
- Construction expenditures for improvements to generating plants, including costs of complying with Environmental Protection Agency (EPA), Maryland and Pennsylvania nitrogen oxides emissions (NOx) regulations. We discuss the NOx regulations and timing of expenditures in Note 11 on page 79.

The above table does not include the financing for the High Desert 750 megawatt gas-fired generation project in California, which is under an operating lease with a term through February 2006. As an operating lease, we do not record any assets or debt associated with the project in our Consolidated Balance Sheets. We are leasing the project and supervising its construction.

Under the terms of the lease, we are required to make payments that represent all or a portion of the lease balance if one of the following events occurs: termination of construction prior to completion or our default under the lease.

Under certain circumstances, we may be required to either post cash collateral equal to the outstanding lease balance or we may elect to purchase the property for the outstanding lease balance. At any time during the term of the lease we have the right to pay off the lease and acquire the asset from the lessor. At December 31, 2001, the outstanding lease balance plus other committed expenses was $271.2 million.

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

- renew the lease upon approval of the lessors,
- elect to purchase the property for a price equal to the lease balance at the end of the term, or
- request the lessor to sell the property.

If we request the lessor to sell the property, we guarantee the sale proceeds up to approximately 83% of the lease balance. The lease balance at the end of the term is currently estimated to be $600 million, which represents the estimated cost of the project; however, this may vary based on the ultimate cost of construction and interest incurred during the construction period.

Regulated Electric and Gas

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

Funding for Capital Requirements

Merchant Energy Business

Funding for the expansion of our merchant energy business is expected from internally generated funds, commercial paper issuances, issuances of long-term debt and equity, leases, and other financing instruments issued by Constellation Energy and its subsidiaries. Specifically related to the Nine Mile Point acquisition, approximately one-half of the purchase price was paid in November 2001, 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%. This note may be prepaid at any time without penalty. We closed the transaction using existing credit facilities. In addition, we also used existing credit facilities to pay Goldman Sachs a total of $355 million. This represented $196.7 million to terminate the power business services agreement with our power marketing operation and $159 million previously recognized as a payable for services rendered.

The projects that our merchant energy business develops typically require substantial capital investment. Most of the projects recently constructed or currently under construction are funded through corporate borrowings by Constellation Energy. Certain other projects in which we have an interest are financed primarily with non-recourse debt that is repaid from the project's cash flows. This debt is collateralized by interests in the physical assets, major project contracts and agreements, cash accounts and, in some cases, the ownership interest in that project.

Longer term, we expect to fund our growth and operating objectives primarily with internally generated funds supplemented, if necessary, by a mixture of debt and equity with an overall goal of maintaining an investment grade credit profile.

BGE

Funding for utility capital expenditures is expected from internally generated funds. During 2002 and 2003, we expect our regulated utility business to provide at least 140% of the cash needed to meet the capital requirements for its operations, excluding cash needed to retire debt. If necessary, additional funding may be obtained from commercial paper issuances, available capacity under credit facilities, the issuance of long-term debt, trust securities, or preference stock, and/or from time to time equity contributions from Constellation Energy.

Other Nonregulated Businesses

Funding for our other nonregulated businesses is expected from internally generated funds, commercial paper issuances, issuances of long-term debt of Constellation Energy, and sales of assets. BGE Home Products & Services can continue to fund capital requirements through sales of receivables. ComfortLink has a revolving credit agreement totaling $50 million to provide liquidity for short-term financial needs.

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 our remaining real estate projects and market conditions in the *Other Nonregulated Businesses* section beginning on page 40.

Committed Amounts

Our total contractual and contingent obligations as of December 31, 2001 are shown in the following table:

	Payments/Expiration				
	Less than one year	One-three years	Four-five years	Over five years	Total
	(In millions)				
Contractual Obligations					
Short-term borrowings	$ 975.0	$ –	$ –	$ –	$ 975.0
Nonregulated long-term debt	720.4	169.8	456.8	357.1	1,704.1
BGE long-term debt	519.8	441.0	511.8	947.7	2,420.3
BGE preference stock	–	130.0	60.0	–	190.0
Fuel and transportation	353.1	330.0	97.9	17.7	798.7
Purchased capacity and energy	16.4	31.5	30.1	98.5	176.5
Operating leases	9.1	63.3	51.2	145.8	269.4
Capital and loan commitments*	81.5	0.8	–	–	82.3
Total contractual obligations	2,675.3	1,166.4	1,207.8	1,566.8	6,616.3
Contingent Obligations					
Letters of credit	245.6	0.2	–	–	245.8
Guarantees, net**	427.8	38.4	666.1	236.1	1,368.4
Total contingent obligations	673.4	38.6	666.1	236.1	1,614.2
Total obligations	$3,348.7	$1,205.0	$1,873.9	$1,802.9	$8,230.5

** Amounts are included for applicable periods in our capital requirements table on page 42.*

*** Guarantees in the above table are shown net of liabilities recorded at December 31, 2001 in our Consolidated Balance Sheets.*

While we included our contingent obligations in the table above, we do not expect to fund the full amounts under the letters of credit and guarantees.

Lease payments under the High Desert operating lease are reflected in the table above. The lease balance at the end of the lease term is currently estimated to be $600 million. This amount is included as a guarantee in the table above.

The table above does not include the fixed payment portions of our mark-to-market energy assets and liabilities. We discuss the expected settlement terms of these contracts in the *Mark-to-Market Energy Revenues* section on page 33.

Liquidity Provisions

We have certain agreements that contain provisions that would require additional collateral upon significant decreases in the Senior Unsecured Debt credit ratings of Constellation Energy. Decreases in Constellation Energy's credit ratings would not trigger an early payment on any of our credit facilities. However, if Constellation Energy's credit ratings were to fall three or more rating levels from our present rating to a level below investment grade, we would have collateral obligations of $470 million under our current contractual obligations related to our power marketing operation. In many cases, customers of our power marketing operation rely on the creditworthiness of Constellation Energy. A decline below investment grade by Constellation Energy would negatively impact the business prospects of that operation.

The credit facilities of Constellation Energy and BGE have limited material adverse change clauses that only consider a material change in financial condition and are not directly affected by decreases in credit ratings. If these clauses are violated, the lending institutions can decline making new advances or issuing new letters of credit, but cannot accelerate existing amounts outstanding. The credit facilities of Constellation Energy contain a provision requiring Constellation Energy to maintain a ratio of debt to capitalization equal to or less than 0.65. The long-term debt indentures of Constellation Energy and BGE do not contain material adverse change clauses or financial covenants.

Constellation Nuclear guarantees the $388 million sellers' note to finance the acquisition of Nine Mile Point. This guarantee contains provisions that require Constellation Nuclear to maintain a net worth of at least $500 million and a ratio of current assets to current liabilities of at least 1.1. Constellation Energy is required to provide adequate support to Constellation Nuclear to meet these provisions. In addition, Constellation Energy provides credit support to Calvert Cliffs and Nine Mile Point to ensure these plants have funds to meet expenses and obligations to safely operate and maintain the plants.

We discuss our short-term borrowings in Note 8 on page 75, long-term debt in Note 9 on page 75, lease requirements in Note 10 on page 77, and commitments and guarantees in Note 11 on page 78.

Market Risk

We are exposed to various market risks, including changes in interest rates, certain commodity prices, credit risk, and equity prices. To manage our market risk, we may enter into various derivative instruments including swaps, forward contracts, futures contracts, and options. We discuss our market risk further in Note 1 on page 59. In this section, we discuss our current market risk and the related use of derivative instruments.

Interest Rate Risk

We are exposed to changes in interest rates as a result of financing through our issuance of variable-rate and fixed-rate debt. We may use derivative instruments to manage our interest rate risks. The following table provides information about our debt obligations that are sensitive to interest rate changes:

Principal Payments and Interest Rate Detail by Contractual Maturity Date

	2002	2003	2004	2005	2006	Thereafter	Total	Fair value at Dec. 31, 2001
				(Dollar amounts in millions)				
Short-term debt								
Variable-rate debt	$975.0	$ –	$ –	$ –	$ –	$ –	$ 975.0	$ 975.0
Average interest rate	3.20%	–	–	–	–	–	3.20%	
Long-term debt								
Variable-rate debt	$835.5	$ 7.9	$ 5.4	$ –	$111.5	$ 218.8	$1,179.1	$1,179.1
Average interest rate	4.31%	3.88%	4.45%	–	6.11%	3.18%	4.27%	
Fixed-rate debt	$404.7	$363.8	$233.7	$425.3	$431.8	$1,086.0	$2,945.3	$3,069.6
Average interest rate	7.78%	7.46%	7.53%	8.32%	5.65%	6.83%	7.26%	

In 2001, we entered into forward starting interest rate swap contracts to manage a portion of our interest rate exposure for anticipated long-term borrowings to refinance our outstanding commercial paper obligations and maturing long-term debt. The swaps have notional or contract amounts that total $800 million with an average rate of 4.9% and expire at the end of the first quarter of 2002. At December 31, 2001, the fair value of these swap contracts was an unrealized pre-tax gain of $36.3 million. In 2002, we entered into additional forward starting interest rate swaps with notional amounts that total $700 million. These swaps have an average rate of 5.9% and expire at the end of the first quarter of 2002.

Commodity Price Risk

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

Merchant Energy Business

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

- Commodity prices—contracts for energy commodities to be purchased or delivered in the future and derivatives related to such commodities exhibit significant price volatility. We use such contracts in our merchant energy business, and if we have not hedged the associated financial exposure, this price volatility could affect our earnings.
- Supply and demand imbalances—supply and demand imbalances can occur because of plant outages, transmission system constraints, or extreme temperatures and can cause significant volatility in energy prices. If we have to buy or sell energy, capacity, or fuel during such periods of volatility to meet fixed-price contract obligations, our earnings could be affected.
- Operational risk—operational risk is the risk that a generating plant will not be available to produce energy. In addition, if we have to buy energy in the market to fulfill a sales requirement because a generating plant is not available to produce that energy, our earnings could be affected adversely.

Commodity price risk arises from the potential for changes in the price of, and transportation costs for, electricity, natural gas, coal, and other commodities; the volatility of commodity prices; and changes in interest rates. A number of factors associated with the structure and operation of the electricity markets significantly influence the level and volatility of prices for energy commodities and related derivative products. These factors include:

- seasonal daily and hourly changes in demand,
- extreme peak demands due to weather conditions,
- available supply resources,
- transportation availability and reliability within and between regions,
- procedures used to maintain the integrity of the physical electricity system during extreme conditions, and
- changes in the nature and extent of federal and state regulations.

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

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

Power Marketing

Our power marketing operation is exposed to market risk as a result of the number and size of unhedged positions it holds. The power marketing operation manages market risk on a portfolio basis, subject to established risk management policies. In order to manage market risk, the power marketing operation uses a variety of derivative and non-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) quantity; and
- option contracts, which convey the right to buy or sell a commodity, financial instrument, or index at a predetermined price.

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

Constellation Power Source uses various methods, including a value at risk model, to measure its exposure to market risk from its energy trading portfolio. Value at risk is a statistical model that attempts to predict risk of loss based on historical market price volatility. 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 commodity price changes over the most recent rolling three-month period. Constellation Power Source's value at risk calculation includes all mark-to-market energy assets and liabilities, including contracts for energy commodities and derivatives that result in physical settlement and contracts that require cash settlement.

The value at risk amount represents the potential pre-tax loss in the fair value of mark-to-market energy assets and liabilities over a one-day holding period 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 $18.0 million as of December 31, 2001, $13.7 million as of December 31, 2000, and $7.2 million as of December 31, 1999. The average, high, and low value at risk for the year ended December 31, 2001 were $18.0 million, $68.9 million, and $8.7 million, respectively. The high value at risk amount for the year represents certain hedge contracts entered into in anticipation of closing an offsetting transaction. When the offsetting transaction closed within several days, the value at risk amount returned to a level more representative of the average for the year.

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

Generation

For 2002, we expect to use the majority of the generating capacity controlled by our merchant energy business to provide standard offer service to BGE or to be sold back to the sellers of Nine Mile Point to service their load requirements. However, beginning in July 2002, we expect approximately 1,000 megawatts of industrial customer load will move from BGE's standard offer service to market-based rates. Going forward, our merchant energy business will supply 100% of the standard offer service to BGE through June 30, 2003 and 90% from July 1, 2003 through June 30, 2006.

As a result of declines in BGE's standard offer service load and the additional 2,900 megawatts of natural gas-fired peaking and combined cycle production facilities under construction, our generation operation has a substantial 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. Our power generation facilities purchase fuel under contracts or on the spot market. Fuel prices may be volatile and the price that can be obtained from power sales may not change at the same rate as changes in fuel costs. Additionally, if one or more of our generating facilities is not able to produce electricity when required due to operational factors, we may have to forego sales opportunities or fulfill fixed-price sale commitments through the operation of other more costly generating facilities or through the purchase of energy in the wholesale market at higher prices.

As part of its overall portfolio, our power marketing operation manages the commodity price risk of our electric generation facilities including power sales, fuel purchases, emission credits, weather risk, and the market risk of outages. In order to manage this risk, our merchant energy business may enter into fixed-price derivative or non-derivative contracts to hedge the variability in future cash flows from forecasted sales of electricity and purchases of fuel. The objectives for entering into such hedges include:

- fixing the price for a portion of anticipated future electricity sales at a level that provides an acceptable return on our electric generation operations, and
- fixing the price of a portion of anticipated fuel purchases for the operation of our power plants.

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

Our merchant energy business has hedged more than 85% of our expected energy output and fuel purchases for 2002. The amount hedged is more than 75% for 2003.

Regulated Electric Business

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. BGE entered into standard offer service arrangements with Constellation Power Source and Allegheny Energy Supply Company to provide the energy and capacity required to meet its standard offer service obligations through June 30, 2006.

Regulated Gas Business

Our regulated gas business may enter into gas futures, options, and swaps to hedge its price risk under our market-based rate incentive mechanism and our off-system gas sales program. We discuss this further in Note 1 on page 59. At December 31, 2001 and 2000, 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 manage 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. Constellation Power Source measures credit risk as the replacement cost for open energy commodity and derivative positions plus amounts owed from counterparties for settled transactions. The replacement cost of open positions represents unrealized gains, net of any unrealized losses, where we have a legally enforceable right of setoff.

As of December 31, 2001, approximately 85% of Constellation Power Source's mark-to-market energy assets consisted of contracts with counterparties rated investment grade by the major credit rating agencies, 5% of these assets consisted of contracts with counterparties rated below investment grade, and 10% of these assets consisted of contracts with governmental authorities which are not rated but which Constellation Power Source assesses are equivalent to investment grade based upon its internal credit ratings.

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

Our merchant energy business sells electricity under long-term power purchase agreements to two California investor-owned utilities that were downgraded by rating agencies to below investment grade. We discuss the credit and other exposures under these agreements in the *Business Environment—Other States* section on page 26.

Equity Price Risk

We are exposed to price fluctuations in equity markets primarily through our financial investments business, our pension plan assets, and our nuclear decommissioning trust funds. We are required by the NRC to maintain an externally funded trust for the costs of decommissioning our nuclear power plants. We discuss our nuclear decommissioning trust funds in more detail in Note 1 on page 62.

A hypothetical 10% decrease in equity prices would result in an approximate $80 million reduction in the fair value of our financial investments that are classified as trading or available-for-sale securities, excluding our investment in Orion. In 2001, the value of our pension plan assets decreased by $42.7 million due to declines in the markets in which plan assets are invested. We describe our financial investments in more detail in Note 4 on page 68, and our pension plans in Note 7 on page 72.

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

The Audit Committee of the Board of Directors, which consists of three 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.

Mayo A. Shattuck III
President and
Chief Executive Officer

E. Follin Smith
Senior Vice President &
Chief Financial Officer

REPORT OF INDEPENDENT ACCOUNTANTS

To the Shareholders of Constellation Energy Group, Inc.

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, comprehensive income, cash flows, common shareholders' equity, capitalization, and income taxes present fairly, in all material respects, the financial position of Constellation Energy Group, Inc. and Subsidiaries ("the Company") at December 31, 2001 and 2000, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2001 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements 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.

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

PricewaterhouseCoopers LLP
Baltimore, Maryland
January 21, 2002

Year Ended December 31,	2001	2000	1999
	(In millions, except per share amounts)		
Revenues			
Nonregulated revenues	$1,214.4	$1,114.0	$1,105.6
Regulated electric revenues	2,039.6	2,134.7	2,258.8
Regulated gas revenues	674.3	603.8	476.5
Total revenues	3,928.3	3,852.5	3,840.9
Expenses			
Operating expenses	2,392.2	2,311.4	2,339.6
Workforce reduction costs	105.7	7.0	–
Contract termination related costs	224.8	–	–
Impairment losses and other costs	202.1	–	64.3
Depreciation and amortization	419.1	470.0	449.8
Taxes other than income taxes	226.6	221.5	227.3
Total expenses	3,570.5	3,009.9	3,081.0
Income from Operations	357.8	842.6	759.9
Other Income	1.3	4.2	7.9
Income Before Fixed Charges and Income Taxes	359.1	846.8	767.8
Fixed Charges			
Interest expense	283.2	282.4	248.0
Interest capitalized and allowance for borrowed funds used during construction	(57.6)	(24.2)	(6.5)
BGE preference stock dividends	13.2	13.2	13.5
Total fixed charges	238.8	271.4	255.0
Income Before Income Taxes	120.3	575.4	512.8
Income Taxes	37.9	230.1	186.4
Income Before Extraordinary Item and Cumulative Effect of Change in Accounting Principle	82.4	345.3	326.4
Extraordinary Loss, Net of Income Taxes of $30.4 (see Note 5)	–	–	(66.3)
Cumulative Effect of Change in Accounting Principle, Net of Income Taxes of $5.6 (see Note 1)	8.5	–	–
Net Income	$ 90.9	$ 345.3	$ 260.1
Earnings Applicable to Common Stock	$ 90.9	$ 345.3	$ 260.1
Average Shares of Common Stock Outstanding	160.7	150.0	149.6
Earnings Per Common Share and Earnings Per Common Share—Assuming Dilution Before Extraordinary Item and Cumulative Effect of Change in Accounting Principle	$ .52	$2.30	$2.18
Extraordinary Loss	–	–	(.44)
Cumulative Effect of Change in Accounting Principle	.05	–	–
Earnings Per Common Share and Earnings Per Common Share—Assuming Dilution	$ .57	$2.30	$1.74

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year Ended December 31,	2001	2000	1999
		(In millions)	
Net Income	$ 90.9	$345.3	$260.1
Other comprehensive income, net of taxes			
Financial securities	124.5	18.6	3.9
Hedging instruments	102.6	–	–
Minimum pension liability	(44.7)	–	–
Comprehensive Income Before Cumulative Effect of Change in Accounting Principle	273.3	363.9	264.0
Cumulative Effect of Change in Accounting Principle, Net of Income Taxes of $22.6	(35.5)	–	–
Comprehensive Income	$237.8	$363.9	$264.0

See Notes to Consolidated Financial Statements.

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

At December 31,	2001	2000
	(In millions)	
Assets		
Current Assets		
Cash and cash equivalents	$ 72.4	$ 182.7
Accounts receivable (net of allowance for uncollectibles of $22.8 and $21.3, respectively)	738.9	792.6
Trading securities	178.2	189.3
Mark-to-market energy assets	398.4	453.1
Fuel stocks	108.0	78.2
Materials and supplies	196.3	151.3
Prepaid taxes other than income taxes	93.4	73.5
Other	74.6	52.8
Total current assets	1,860.2	1,973.5
Investments and Other Assets		
Real estate projects and investments	210.7	290.3
Investments in power projects	499.1	510.6
Investment in Orion Power Holdings, Inc.	442.5	192.0
Financial investments	60.7	161.0
Nuclear decommissioning trust funds	683.5	228.7
Net pension asset	–	93.2
Mark-to-market energy assets	1,819.8	2,069.3
Other	207.4	123.0
Total investments and other assets	3,923.7	3,668.1
Property, Plant and Equipment		
Regulated property, plant and equipment		
Plant in service	4,862.4	4,780.3
Construction work in progress	81.8	75.3
Plant held for future use	4.5	4.5
Total regulated property, plant and equipment	4,948.7	4,860.1
Nonregulated generation property, plant and equipment	6,551.1	5,286.8
Other nonregulated property, plant and equipment	192.9	147.0
Nuclear fuel (net of amortization)	169.5	128.3
Accumulated depreciation	(4,161.8)	(3,756.7)
Net property, plant and equipment	7,700.4	6,665.5
Deferred Charges		
Regulatory assets (net)	463.8	514.9
Other	129.5	117.3
Total deferred charges	593.3	632.2
Total Assets	$14,077.6	$12,939.3

See Notes to Consolidated Financial Statements.

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

At December 31,	2001	2000
	(In millions)	
Liabilities and Capitalization		
Current Liabilities		
Short-term borrowings	$ 975.0	$ 243.6
Current portion of long-term debt	1,406.7	906.6
Accounts payable	534.4	750.0
Mark-to-market energy liabilities	323.3	358.2
Dividends declared	23.0	66.5
Other	297.1	250.8
Total current liabilities	3,559.5	2,575.7
Deferred Credits and Other Liabilities		
Deferred income taxes	1,431.0	1,353.2
Mark-to-market energy liabilities	1,476.5	1,636.3
Net pension liability	173.3	–
Postretirement and postemployment benefits	330.9	265.2
Deferred investment tax credits	93.4	101.4
Other	266.9	484.2
Total deferred credits and other liabilities	3,772.0	3,840.3
Capitalization		
Long-term debt	2,712.5	3,159.3
BGE preference stock not subject to mandatory redemption	190.0	190.0
Common shareholders' equity	3,843.6	3,174.0
Total capitalization	6,746.1	6,523.3
Commitments, Guarantees, and Contingencies (see Note 11)		
Total Liabilities and Capitalization	$14,077.6	$12,939.3

See Notes to Consolidated Financial Statements.

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

Year Ended December 31,	2001	2000	1999
		(In millions)	
Cash Flows From Operating Activities			
Net income	$ 90.9	$ 345.3	$ 260.1
Adjustments to reconcile to net cash provided by operating activities			
Cumulative effect of change in accounting principle	(8.5)	–	–
Extraordinary loss	–	–	66.3
Depreciation and amortization	468.9	524.8	505.9
Deferred income taxes	(26.5)	42.1	13.0
Investment tax credit adjustments	(8.1)	(8.4)	(8.6)
Deferred fuel costs	37.6	2.8	(61.1)
Accrued pension and postemployment benefits	55.3	27.9	36.1
Gain on sale of investments	(40.7)	(64.1)	–
Loss (gain) on sale of subsidiaries and plant assets	43.3	(13.3)	–
Deregulation transition cost	–	24.0	–
Workforce reduction costs	105.7	7.0	–
Contract termination related costs	26.2	–	–
Impairment losses and other costs	158.7	–	64.3
Equity in earnings of affiliates and joint ventures (net)	2.0	(5.3)	(7.6)
Changes in mark-to-market energy assets and liabilities	109.5	(379.6)	(114.3)
Changes in other current assets	(57.7)	(230.7)	(216.4)
Changes in other current liabilities	(218.8)	406.2	121.0
Other	(164.5)	172.2	20.3
Net cash provided by operating activities	573.3	850.9	679.0
Cash Flows From Investing Activities			
Purchases of property, plant and equipment and other capital expenditures	(1,318.3)	(1,079.0)	(616.5)
Acquisition of Nine Mile Point	(382.7)	–	–
Sale of (investment in) Orion	26.2	(101.5)	(97.7)
Contributions to nuclear decommissioning trust funds	(22.0)	(13.2)	(17.6)
Purchases of marketable equity securities	(33.2)	(80.8)	(27.3)
Sales of marketable equity securities	132.6	110.2	34.9
Proceeds from the sale of property, plant, and equipment	112.0	20.8	–
Other investments	12.7	37.0	109.1
Net cash used in investing activities	(1,472.7)	(1,106.5)	(615.1)
Cash Flows From Financing Activities			
Net issuance (maturity) of short-term borrowings	731.4	(127.9)	371.5
Proceeds from issuance of			
Long-term debt	1,175.2	1,374.0	302.8
Common stock	504.4	35.9	9.6
Repayment of long-term debt	(1,510.2)	(697.0)	(584.4)
Redemption of preference stock	–	–	(7.0)
Common stock dividends paid	(120.7)	(250.7)	(251.1)
Other	9.0	11.3	13.7
Net cash provided by (used in) financing activities	789.1	345.6	(144.9)
Net (Decrease) Increase in Cash and Cash Equivalents	(110.3)	90.0	(81.0)
Cash and Cash Equivalents at Beginning of Year	182.7	92.7	173.7
Cash and Cash Equivalents at End of Year	$ 72.4	$ 182.7	$ 92.7
Other Cash Flow Information:			
Cash paid during the year for:			
Interest (net of amounts capitalized)	$ 238.3	$ 268.2	$ 245.3
Income taxes	$ 101.5	$ 184.7	$ 165.6

Non-Cash Transaction:

In connection with our purchase of Nine Mile Point, the fair value of the net assets purchased was $770.8 million. We paid $382.7 million in cash, including settlement costs, and incurred a sellers' note of $388.1 million as discussed further in Note 14 on page 86.

See Notes to Consolidated Financial Statements.

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

Years Ended December 31, 2001, 2000, and 1999	Common Stock Shares	Common Stock Amount	Retained Earnings	Accumulated Other Comprehensive Income	Total Amount
	(Dollar amounts in millions, number of shares in thousands)				
Balance at December 31, 1998	149,246	$1,485.1	$1,490.3	$ 20.5	$2,995.9
Net income			260.1		260.1
Common stock dividend declared ($1.68 per share)			(251.3)		(251.3)
Common stock issued	310	9.6			9.6
Other		(0.7)			(0.7)
Net unrealized gain on securities, net of taxes of $3.2				3.9	3.9
Balance at December 31, 1999	149,556	1,494.0	1,499.1	24.4	3,017.5
Net income			345.3		345.3
Common stock dividend declared ($1.68 per share)			(251.8)		(251.8)
Common stock issued	976	35.9			35.9
Other		8.8	(0.3)		8.5
Net unrealized gain on securities, net of taxes of $9.5				18.6	18.6
Balance at December 31, 2000	150,532	1,538.7	1,592.3	43.0	3,174.0
Net income			90.9		90.9
Common stock dividend declared ($.48 per share)			(77.1)		(77.1)
Common stock issued	13,176	504.4			504.4
Other		(0.9)	5.4		4.5
Cumulative effect of change in accounting principle, net of taxes of $22.6				(35.5)	(35.5)
Net unrealized gain on securities, net of taxes of $71.8				124.5	124.5
Net unrealized gain on hedging instruments, net of taxes of $65.6				102.6	102.6
Minimum pension liability, net of taxes of $29.3				(44.7)	(44.7)
Balance at December 31, 2001	163,708	$2,042.2	$1,611.5	$189.9	$3,843.6

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

At December 31,	2001	2000
	(In millions)	
Long-Term Debt		
Long-term debt of Constellation Energy		
7⅞% Notes, due April 1, 2005	$ 300.0	$ 300.0
Floating rate notes, due April 4, 2003	–	200.0
Extendible notes, due June 21, 2010	–	300.0
Floating rate reset notes, due March 15, 2002	–	200.0
Floating rate notes, due January 17, 2002	635.0	–
Total long-term debt of Constellation Energy	935.0	1,000.0
Long-term debt of nonregulated businesses		
Tax-exempt debt transferred from BGE effective July 1, 2000		
Pollution control loan, due July 1, 2011	36.0	36.0
Port facilities loan, due June 1, 2013	48.0	48.0
Adjustable rate pollution control loan, due July 1, 2014	20.0	20.0
5.55% Pollution control revenue refunding loan, due July 15, 2014	47.0	47.0
Economic development loan, due December 1, 2018	35.0	35.0
6.00% Pollution control revenue refunding loan, due April 1, 2024	75.0	75.0
Floating rate pollution control loan, due June 1, 2027	8.8	8.8
5½% Installment series, due July 15, 2002	6.7	7.6
District Cooling facilities loan, due December 1, 2031	25.0	–
Loans under revolving credit agreements	46.0	34.0
11% Installment note, due November 7, 2006	388.1	–
Mortgage and construction loans		
Floating rate mortgage notes and construction loans, due through 2005	13.8	51.3
Other mortgage notes ranging from 4.25% to 9.65% due March 15, 2009 to November 1, 2033	19.7	20.3
Unsecured notes	–	287.0
Total long-term debt of nonregulated businesses	769.1	670.0
First Refunding Mortgage Bonds of BGE		
8⅜% Series, due August 15, 2001	–	122.2
7¼% Series, due July 1, 2002	124.0	124.0
6½% Series, due February 15, 2003	124.8	124.8
6⅛% Series, due July 1, 2003	124.9	124.9
5½% Series, due April 15, 2004	125.0	125.0
Remarketed floating rate series, due September 1, 2006	111.5	111.5
7½% Series, due January 15, 2007	123.5	123.5
6⅝% Series, due March 15, 2008	124.9	124.9
7½% Series, due March 1, 2023	98.1	109.9
7½% Series, due April 15, 2023	84.0	84.0
Total First Refunding Mortgage Bonds of BGE	1,040.7	1,174.7
Other long-term debt of BGE		
5.25% Notes, due December 15, 2006	300.0	–
Floating rate reset notes, due February 5, 2002	200.0	–
Floating rate reset notes, due October 19, 2001	–	200.0
Medium-term notes, Series B	23.1	23.1
Medium-term notes, Series C	25.5	25.5
Medium-term notes, Series D	68.0	128.0
Medium-term notes, Series E	200.0	200.0
Medium-term notes, Series G	140.0	200.0
Medium-term notes, Series H	–	27.0
6.75% Remarketable or redeemable securities, due December 15, 2012	173.0	173.0
Total other long-term debt of BGE	1,129.6	976.6
BGE obligated mandatorily redeemable trust preferred securities of subsidiary trust holding solely 7.16% deferrable interest subordinated debentures due June 30, 2038	250.0	250.0
Unamortized discount and premium	(5.2)	(5.4)
Current portion of long-term debt	(1,406.7)	(906.6)
Total long-term debt	$2,712.5	$3,159.3

See Notes to Consolidated Financial Statements.

continued on next page

At December 31,	2001	2000
	(In millions)	
BGE Preference Stock		
Cumulative preference stock not subject to mandatory redemption, 6,500,000 shares authorized		
7.125%, 1993 Series, 400,000 shares outstanding, not callable prior to July 1, 2003	$ 40.0	$ 40.0
6.97%, 1993 Series, 500,000 shares outstanding, not callable prior to October 1, 2003	50.0	50.0
6.70%, 1993 Series, 400,000 shares outstanding, not callable prior to January 1, 2004	40.0	40.0
6.99%, 1995 Series, 600,000 shares outstanding, not callable prior to October 1, 2005	60.0	60.0
Total preference stock not subject to mandatory redemption	190.0	190.0
Common Shareholders' Equity		
Common stock without par value, 250,000,000 shares authorized; 163,707,950 and 150,531,716 shares issued and outstanding at December 31, 2001 and 2000, respectively. (At December 31, 2001 11,797,976 shares were reserved for the Shareholder Investment Plan and 6,000,000 were reserved for the long-term incentive plans.)	2,042.2	1,538.7
Retained earnings	1,611.5	1,592.3
Accumulated other comprehensive income	189.9	43.0
Total common shareholders' equity	3,843.6	3,174.0
Total Capitalization	$6,746.1	$6,523.3

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

Year Ended December 31,	2001	2000	1999
		(Dollar amounts in millions)	
Income Taxes			
Current			
Federal	$45.5	$148.2	$176.3
State	27.0	48.2	5.7
Current taxes charged to expense	72.5	196.4	182.0
Deferred			
Federal	(22.4)	53.9	5.8
State	(4.1)	(11.8)	7.2
Deferred taxes charged to expense	(26.5)	42.1	13.0
Investment tax credit adjustments	(8.1)	(8.4)	(8.6)
Income taxes per Consolidated Statements of Income	$37.9	$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)	$133.5	$588.6	$526.3
Statutory federal income tax rate	35%	35%	35%
Income taxes computed at statutory federal rate	46.7	206.0	184.2
Increases (decreases) in income taxes due to			
Depreciation differences not normalized on regulated activities	5.6	12.6	15.3
Allowance for equity funds used during construction	(1.1)	(0.9)	(2.2)
Amortization of deferred investment tax credits	(8.1)	(8.4)	(8.6)
Tax credits flowed through to income	(13.4)	(6.5)	(3.2)
Amortization of deferred tax rate differential on regulated activities	(2.1)	(2.9)	(3.0)
State income taxes, net of federal income tax benefit	13.5	31.7	8.2
Other	(3.2)	(1.5)	(4.3)
Total income taxes	$ 37.9	$230.1	$186.4
Effective income tax rate	28.4%	39.1%	35.4%

At December 31,	2001	2000
	(Dollar amounts in millions)	
Deferred Income Taxes		
Deferred tax liabilities		
Net property, plant and equipment	$1,156.0	$1,135.5
Income taxes recoverable through future rates	31.4	32.8
Deferred termination and postemployment costs	7.0	13.6
Deferred fuel costs	11.7	24.9
Power marketing and risk management activities	776.4	819.4
Deferred electric generation-related regulatory assets	87.1	93.7
Financial investments and hedging instruments	153.9	42.6
Other	140.9	135.6
Total deferred tax liabilities	2,364.4	2,298.1
Deferred tax assets		
Accrued pension and postemployment benefit costs	132.7	76.5
Deferred investment tax credits	35.1	35.5
Nuclear decommissioning liability	32.1	28.2
Power marketing and risk management activities	549.1	638.2
Reduction of investments	82.3	29.8
Other	102.1	136.7
Total deferred tax assets	933.4	944.9
Deferred tax liability, net	$1,431.0	$1,353.2

See Notes to Consolidated Financial Statements.

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

Constellation Energy Group, Inc. and Subsidiaries

Note 1. Significant Accounting Policies

Nature of Our Business

Constellation Energy Group, Inc. (Constellation Energy) is a North American energy company that conducts its business through various subsidiaries including a merchant energy business and Baltimore Gas and Electric Company (BGE). Our merchant energy business generates and markets wholesale electricity in North America. BGE is an electric and gas public transmission and distribution utility company with a service territory that covers the City of Baltimore and all or part of ten counties in central Maryland. We describe our operating segments in Note 3 on page 66.

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.

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.

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 (include as an asset or liability in our Consolidated Balance Sheets and exclude from our Consolidated Statements of Income) certain utility expenses and income as regulatory assets and liabilities. We have recorded these regulatory assets and liabilities in our Consolidated Balance Sheets in accordance with Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulation.* We summarize and discuss our regulatory assets and liabilities further in Note 6 on page 71.

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 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 5 on page 70.

Revenues

Nonregulated Businesses

Our subsidiary, Constellation Power Source, uses the mark-to-market method of accounting, as discussed below, to account for a portion of its power marketing activities. We record all other nonregulated revenues in the period earned for services rendered, commodities or products delivered, or contracts settled. Equity in earnings from our investments in power projects is included in revenues.

Power marketing activities include new origination transactions and risk management activities using contracts for energy, other energy-related commodities, and related derivative contracts. We use the mark-to-market method of accounting for portions of Constellation Power Source's activities as required by EITF 98-10, *Accounting for Contracts Involved in Energy Trading and Risk Management Activities.* Under the mark-to-market method of accounting, we record the fair value of commodity and derivative contracts as mark-to-market energy assets and liabilities at the time of contract execution. We record reserves to reflect uncertainties associated with certain estimates inherent in the determination of fair value. Mark-to-market energy revenues include:

- the fair value of new transactions at origination,
- unrealized gains and losses from changes in the fair value of open positions,
- net gains and losses from realized transactions, and
- changes in reserves.

We record the changes in mark-to-market energy assets and liabilities on a net basis in "Nonregulated revenues" in our Consolidated Statements of Income. Mark-to-market energy assets and liabilities are comprised of a combination of energy and energy-related derivative and non-derivative contracts. While some of these contracts represent commodities or instruments for which prices are available from external sources, other commodities and certain contracts are not actively traded and are valued using modeling techniques to determine expected future market prices, contract quantities, or both. The market prices used to determine fair value reflect management's best estimate considering various factors, including closing exchange and over-the-counter quotations, time value, and volatility factors. However, it is possible that future market prices could vary from those used in recording mark-to-market energy assets and liabilities, and such variations could be material.

Certain power marketing and risk management transactions entered into under master agreements and other arrangements provide our merchant energy business with a right of setoff in the event of bankruptcy or default by the counterparty. We report such transactions net in the balance sheets in accordance with FASB Interpretation No. 39, *Offsetting of Amounts Related to Certain Contracts.*

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 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 6 on page 71.

Natural Gas

We charge our gas customers for the natural gas they purchase from us using "gas cost adjustment clauses" set by the Maryland PSC. These clauses operate similarly to the electric fuel rate clause described earlier in this note. However, the Maryland PSC approved a modification of the gas cost adjustment clauses to provide a market-based rates incentive mechanism. Under market-based rates, our actual cost of gas is compared to a market index (a measure of the market price of gas in a given period). The difference between our actual cost and the market index is shared equally between shareholders and customers. Effective November 2001, the Maryland PSC approved an order that modifies certain provisions of the market-based rates incentive mechanism. These provisions require that BGE secure fixed-price contracts for at least 10%, but not more than 20%, of forecasted system supply requirements for the November through March period. These fixed price contracts are not subject to sharing under the market-based rates incentive mechanism.

Risk Management

We are exposed to market risk, including changes in interest rates and the impact of market fluctuations in the price and transportation costs of electricity, natural gas, and other commodities as discussed further in Note 12 on page 83. We use interest rate swaps to manage our interest rate exposures associated with new debt issuances. These swaps are designated as cash-flow hedges under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities,* as discussed later in this note, with our gains recorded in "Other current assets" in our Consolidated Balance Sheets and "Accumulated other comprehensive income," in our Consolidated Statements of Common Shareholders' Equity and Consolidated Statements of Capitalization, in anticipation of planned financing transactions. Any gain or loss on the hedges will be reclassified from "Accumulated other comprehensive income" into "Interest expense" and be included in earnings during the periods in which the interest payments being hedged occur.

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

Merchant Energy Business

The power marketing operation manages market risk on a portfolio basis, subject to established risk management policies. The power marketing operation uses a variety of derivative and non-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) quantity; and
- option contracts, which convey the right to buy or sell a commodity, financial instrument, or index at a predetermined price.

As part of its overall portfolio, the power marketing operation manages the commodity price risk of our electric generation facilities, including power sales, fuel purchases, emission credits, weather risk, and the market risk of outages. In order to manage this risk, we may enter into fixed-price derivative or non-derivative contracts to hedge the variability in future cash flows from forecasted sales of electricity and purchases of fuel. The objectives for entering into such hedges include:

- fixing the price for a portion of anticipated future electricity sales at a level that provides an acceptable return on our electric generation operations, and
- fixing the price of a portion of anticipated fuel purchases for the operation of our power plants.

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

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

Regulated Electric Business

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. BGE entered into standard offer service arrangements with Constellation Power Source and Allegheny Energy Supply Company to provide the energy and capacity required to meet its standard offer service obligations through June 30, 2006.

Regulated Gas Business

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, 2001 and 2000.

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
Credit risk is the loss that may result from counterparty nonperformance. We are exposed to credit risk, primarily through Constellation Power Source. Constellation Power Source uses credit policies to manage 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. Constellation Power Source measures credit risk as the replacement cost for open energy commodity and derivative positions plus amounts owed from counterparties for settled transactions. The replacement cost of open positions represents unrealized gains, net of any unrealized losses, where we have a legally enforceable right of setoff.

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

Electric and gas utilities, cooperatives, and energy marketers comprise the majority of counterparties underlying our assets from power marketing and risk management activities. We held cash collateral from counterparties totaling $3.5 million as of December 31, 2001 and $103.3 million as of December 31, 2000. These amounts are included in "Other deferred credits and other liabilities" in our Consolidated Balance Sheets.

Taxes
We summarize our income taxes in our Consolidated Statements of Income Taxes on page 56. 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 Taxes—current and deferred. We describe each of these below:

- current income tax expense consists solely of regular tax less applicable tax credits, and
- deferred income tax expense is equal to the changes in the net deferred income tax liability, excluding amounts charged or credited to accumulated other comprehensive income. Our deferred income tax expense is increased or reduced for changes to the "Income taxes recoverable through future rates (net)" regulatory asset (described later in this note) during the year.

Investment Tax Credits
We have deferred the investment tax 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 for income tax return purposes. The tax effects of the differences in these items are reported as deferred income tax assets or liabilities in our Consolidated Balance Sheets. We measure the deferred income tax assets and liabilities using income tax rates that are currently in effect.

A portion of our total deferred income tax liability relates to our regulated utility business, but has not been reflected in the rates we charge our customers. We refer to this portion of the liability as "Income taxes recoverable through future rates (net)." We have recorded that portion of the net liability as a regulatory asset in our Consolidated Balance Sheets. We discuss this further in Note 6 on page 71.

State and Local Taxes
As discussed in Note 5 on page 69, 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
All highly liquid investments with original maturities of three months or less are considered cash equivalents.

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

Real Estate Projects and Investments

In Note 4 on page 68, we summarize the real estate projects and investments that are in our Consolidated Balance Sheets. The projects and investments primarily consist of:

- approximately 1,600 acres of land holdings in various stages of development located at 11 sites in the central Maryland region,
- a 4,500 unit mixed-use planned unit development located in Anne Arundel County, Maryland of which 1,300 residential units and 11 acres for commercial development remain,
- an operating waste water treatment plant located in Anne Arundel County, Maryland, 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 4 on page 68, we summarize the financial investments that are in our Consolidated Balance Sheets.

SFAS No. 115, *Accounting for Certain Investments in Debt and Equity Securities*, applies particular requirements to some of our investments in debt and equity securities. We report those investments at fair value, and we use either specific identification or average cost to determine their cost for computing realized gains or losses. We classify these investments as either trading securities or available-for-sale securities, which we describe separately below. We report investments that are not covered by SFAS No. 115 at their cost.

Trading Securities

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

Available-for-Sale Securities

We classify our investments in the nuclear decommissioning trust funds as available-for-sale securities. We describe the nuclear decommissioning trusts and the reserves under the heading "Nuclear Decommissioning" later in this note.

In addition, our other nonregulated businesses classify some of their investments in marketable equity securities as available-for-sale securities, including the investment in Orion Power Holdings, Inc. (Orion) effective June 1, 2001. We discuss the accounting for the investment in Orion in more detail in Note 4 on page 68.

We include any unrealized gains or losses on our available-for-sale securities in "Accumulated other comprehensive income" in our Consolidated Statements of Common Shareholders' Equity and Consolidated Statements of Capitalization.

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

SFAS No. 121, *Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of*, requires us to evaluate certain assets that have long lives (generating property and equipment and real estate) to determine if they are impaired if certain conditions exist. We determine if long-lived assets are impaired by comparing their undiscounted expected future cash flows to their carrying amount in our accounting records. We would record an impairment loss if the undiscounted expected future cash flows from an asset were less than the carrying amount of the asset. Additionally, we evaluate our equity-method investments to determine whether they have experienced a loss in value that is considered other than a temporary decline in value.

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

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 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 $150 million at December 31, 2001 and $143 million at December 31, 2000.

The "Nonregulated generation property, plant and equipment" in our Consolidated Balance Sheets includes nonregulated generation construction work in progress of $1,158.6 million at December 31, 2001 and $908.7 million at December 31, 2000.

When we retire or dispose of property, plant and equipment, we remove the asset's cost from our Consolidated Balance Sheets. We charge this cost to accumulated depreciation for assets that were depreciated under the composite, straight-line method. This includes regulated utility property, plant and equipment and nonregulated generating assets previously owned by the regulated utility. For all other assets, we remove the accumulated depreciation and amortization amounts from our Consolidated Balance Sheets and record any gain or loss in our Consolidated Statements of Income.

The costs of maintenance and certain replacements are charged to "Operating expenses" in our Consolidated Statements of Income as incurred.

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

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

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

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

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

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

Nuclear Decommissioning
We record an expense and a reserve for the costs expected to be incurred in the future to decommission the radioactive portion of Calvert Cliffs based on a sinking fund methodology. The accumulated decommissioning reserve is recorded in "Accumulated depreciation" in our Consolidated Balance Sheets. The total reserve was $304.6 million at December 31, 2001 and $275.4 million at December 31, 2000. Our contributions to the nuclear decommissioning trust funds were $22.0 million for 2001, $13.2 million for 2000, and $17.6 million for 1999.

Under the Maryland PSC's order deregulating electric generation, BGE's customers must pay a total of $520 million in 1993 dollars, adjusted for inflation, to decommission Calvert Cliffs. BGE is collecting this amount on behalf of and passing it to Calvert Cliffs Nuclear Power Plant, Inc. Calvert Cliffs Nuclear Power Plant, Inc. is responsible for any difference between this amount and the actual costs to decommission the plant.

We recorded a reserve for the costs expected to be incurred in the future to decommission the radioactive portion of Nine Mile Point under the discounted future cash flows methodology. The total reserve was $224.4 million at December 31, 2001. We have determined that the decommissioning trust funds established for Nine Mile Point are adequately funded to cover the future costs to decommission the radioactive portions of the plant and as such, no contributions were made to the trust funds during the year ended December 31, 2001.

In accordance with Nuclear Regulatory Commission (NRC) regulations, we maintain external decommissioning trusts to fund the costs expected to be incurred to decommission Calvert Cliffs and Nine Mile Point. The assets in the trusts are reported in "Nuclear decommissioning trust funds" 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.

We classify the investments in the nuclear decommissioning trust funds as available-for-sale securities, and we report these investments at fair value in our Consolidated Balance Sheets as previously discussed in this note.

As owners of Calvert Cliffs Nuclear Power Plant, we are required, along with other domestic utilities, by the Energy Policy Act of 1992 to make contributions to a fund for decommissioning and decontaminating the Department of Energy's uranium enrichment facilities. The contributions are generally payable over 15 years with escalation for inflation and are based upon the proportionate amount of uranium enriched by the Department of Energy for each utility. We amortize the deferred costs of decommissioning and decontaminating the Department of Energy's uranium enrichment facilities. The previous owners retained the obligation for Nine Mile Point.

Capitalized Interest and Allowance for Funds Used During Construction

Capitalized Interest
With the issuance of the Restructuring Order, we ceased accruing AFC (discussed on the next page) for electric generation-related construction projects.

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

Allowance for Funds Used During Construction (AFC)
We finance regulated utility construction projects with borrowed funds and equity funds. We are allowed by the Maryland PSC to record the costs of these funds as part of the cost of construction projects in our Consolidated Balance Sheets. We do this through the AFC, which we calculate using a rate authorized by the Maryland PSC. We bill our customers for the AFC plus a return after the utility property is placed in service.

The AFC rates are 9.4% for electric plant, 8.6% for gas plant, and 9.2% for common plant. We compound AFC annually.

Long-Term Debt

We defer all costs related to the issuance of long-term debt. These costs include underwriters' commissions, discounts or premiums, other costs such as legal, accounting, and regulatory fees, and printing costs. We amortize these costs to expense over the life of the debt.

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

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 Adopted

On January 1, 2001, we adopted SFAS No. 133, as amended by SFAS No. 138, *Accounting for Certain Derivative Instruments and Certain Hedging Activities.*

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 use derivatives in connection with our power marketing and risk management activities and to hedge the risk of variations in future cash flows from forecasted purchases and sales of electricity and gas in our electric generation operations as more fully described in the *Risk Management* section on page 59. Under SFAS No. 133, changes in the value of derivatives designated as hedges that are effective in offsetting the variability in cash flows of forecasted transactions are recognized in other comprehensive income until the forecasted transactions occur. The ineffective portion of changes in fair value of derivatives used as cash-flow hedges is immediately recognized in earnings.

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

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

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

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

Recently Issued Accounting Standards

In 2001, the FASB issued SFAS No. 141, *Business Combinations*, SFAS No. 142, *Goodwill and Other Intangible Assets*, SFAS No. 143, *Accounting for Obligations Associated with the Retirement of Long-Lived Assets*, and SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets.*

SFAS No. 141 requires all business combinations to be accounted for under the purchase method. Use of the pooling-of-interests method is prohibited for business combinations initiated after June 30, 2001. This statement also establishes criteria for the separate recognition of intangible assets acquired in a business combination. We do not expect the adoption of this statement to have a material impact on our financial results.

SFAS No. 142 requires that goodwill no longer be amortized to earnings, but instead be subject to periodic testing for impairment. This statement is effective for fiscal years beginning after December 15, 2001, with earlier application permitted only in specified circumstances. We do not expect the adoption of this statement to have a material impact on our financial results.

SFAS No. 143 provides the accounting requirements for asset retirement obligations associated with tangible long-lived assets. This statement is effective for fiscal years beginning after June 15, 2002, and early adoption is permitted. Currently, we are evaluating this statement and have not determined its impact on our financial results, however, it could be material.

SFAS No. 144 replaces FASB Statement No. 121, *Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of.* SFAS No. 144 addresses financial reporting for the impairment or disposal of long-lived assets. This statement is effective for fiscal years beginning after December 15, 2001, and interim periods within those fiscal years, with early application encouraged. We do not expect the adoption of this statement to have a material impact on our financial results. However, we expect to reclassify our senior-living facilities business as a discontinued operation in the first quarter of 2002 as required under this standard.

Note 2. Contract Termination, Workforce Reduction, and Other Special Costs

2001 Events

	Pre-Tax	After-Tax
	(In millions)	
Workforce reduction costs:		
Voluntary termination benefits—VSERP	$ 70.1	$ 42.5
Settlement and curtailment charges	16.3	9.9
Involuntary severance accrual	19.3	11.7
Total workforce reduction costs	105.7	64.1
Contract termination related costs	224.8	139.6
Impairment losses and other costs:		
Loss on sale of Guatemalan operation	43.3	28.1
Impairments of real estate, senior-living, and international investments	107.3	69.7
Cancellation of domestic power projects	46.9	30.5
Reduction of financial investment	4.6	2.8
Total impairment losses and other costs	202.1	131.1
Total special costs	$532.6	$334.8

Workforce Reduction Costs

Voluntary Special Early Retirement Programs—VSERP

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

Since employees electing to participate in the age 55 or older VSERP had to make their elections by the end of 2001, the cost of that program was reflected in 2001. The $70.1 million in the above table reflects the portion of the total cost of that program charged to expense for the 507 employees that elected to participate. BGE recorded $37.9 million of this amount. BGE also recorded $13.7 million on its balance sheet as a regulatory asset related to its gas business as discussed in Note 6 on page 71.

Settlement and Curtailment Charges

In connection with the age 55 or older VSERP, a significant number of the participants in our nonqualified pension plans are retiring. As a result, we recognized a settlement loss of approximately $10.5 million and a curtailment loss of approximately $5.8 million for those plans in accordance with SFAS No. 88, *Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits.* BGE recorded $6.6 million of this amount. Additional details on the VSERP and their impact on our pension and postretirement benefit plans are discussed in Note 7 on page 72.

Involuntary Severance Accrual

The voluntary programs were designed, offered, and timed to minimize the number of employees who will be involuntarily severed under our overall workforce reduction plan. Our workforce reduction plan identified 435 jobs to be eliminated over and above position reductions expected to be satisfied through the age 55 and over VSERP and was specific as to company, organizational unit, and position. However, the number of employees that will elect to voluntarily retire under the age 50 to 54 VSERP and how many will thereafter be involuntarily severed is unknown until after the election period of the VSERP ends in February 2002.

In accordance with EITF 94-3, *Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring),* the Company recognized a liability of $25.1 million at December 31, 2001 for the targeted number of involuntary terminations that will result if no employees elect the age 50 to 54 VSERP. The $19.3 million in the table above represents involuntary severance charged to expense in 2001 in connection with our workforce reduction programs. BGE recorded $12.5 million of this amount. BGE also recorded $5.8 million on its balance sheet as a regulatory asset related to its gas business as discussed in Note 6 on page 71. We will record any additional cost in excess of the 2001 involuntary severance accrual for those eligible participants that elect the 50 to 54 VSERP in 2002.

Contract Termination Related Costs

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

We also announced the termination of our power business services agreement with Goldman Sachs. We paid Goldman Sachs a total of $355 million, representing $196.7 million to terminate the power business services agreement with our power marketing operation and $159 million previously recognized as a payable for services rendered under the agreement. Goldman Sachs also will not make an equity investment in our merchant energy business as previously announced.

In addition, we terminated a software agreement we had whereby Goldman Sachs would provide maintenance, support, and minor upgrades to our risk management and trading system. We recognized $17.6 million in expense in the fourth quarter of 2001 representing the unamortized prepaid costs related to this agreement. Finally, we incurred approximately $10.5 million in employee-related expenses and advisory costs from investment bankers and legal counsel. In total, we recognized expenses of approximately $224.8 million in the fourth quarter of 2001 relating to the termination of our relationship with Goldman Sachs and our decision not to separate.

Impairment Losses and Other Costs

Sale of Guatemalan Operation

On November 8, 2001, we sold our Guatemalan power plant operations to an affiliate of Duke Energy International, LLC, the international business unit of Duke Energy. Through this sale, Duke Energy acquired Grupo Generador de Guatemala y Cia., S.C.A., which owns two generating plants at Esquintla and Lake Amatitlan in Guatemala. The combined capacity of the plants is 167 megawatts. We decided to sell our Guatemalan operations to focus our efforts on our core energy businesses. As a result of this transaction, we are no longer committed to making significant future capital investments in a non-core operation. We recorded a $43.3 million loss on this sale.

Impairments of Real Estate, Senior-Living, and Other International Investments

In the fourth quarter of 2001, our other nonregulated businesses recorded $107.3 million in impairments of certain real estate projects, senior-living facilities, and international assets to reflect the fair value of these investments. These investments represent non-core assets with a book value of approximately $140.6 million after these impairments. As part of our focus on capital and cash requirements and on our core energy businesses, the following occurred:

- We decided to sell six real estate projects without further development and all of our 18 senior-living facilities in 2002 and accelerate the exit strategies for two other real estate projects that we will continue to hold and own over the next several years. The real estate projects include approximately 1,300 acres of land holdings in various stages of development located in seven sites in the central Maryland region and an operating waste water treatment plant located in Anne Arundel County, Maryland.
- We decided to accelerate the exit strategy for our interest in a Panamanian electric distribution company. As a non-core asset, management has decided to reduce the cost and risk of holding this asset indefinitely and intends to dispose of this asset. We believe a sale of this investment can be completed by mid-to-late 2003.
- We incurred an other than temporary decline in our equity method investment in the Bolivian Generating Group, which owns an interest in an electric generation concession in Bolivia. This decline in value resulted from a deterioration of our investment's position in the dispatch curve of its capacity market. As a result, we recorded the impairment in accordance with the provisions of Accounting Principles Board Opinion No. 18, *The Equity Method of Accounting for Investments in Common Stock.*

The impairments of our real estate, senior-living facilities, and Panama investments were recorded in accordance with the provisions of SFAS No. 121. These impairments resulted from our change from an intent to hold to an intent to sell certain of these non-core assets in 2002, and our decision to limit future costs and risks by accelerating the exit strategies for certain assets that cannot be sold by the end of 2002. Previously, our strategy for these investments was to hold them until we could obtain reasonable value. Under that strategy, the expected cash flows were greater than our investment and no impairment was recognized.

Impairment of Domestic Power Projects

In the fourth quarter of 2001, our merchant energy business recorded impairments of $46.9 million primarily due to $40.8 million in impairments under SFAS No. 121 associated with the termination of our planned development projects in Texas, California, Florida, and Massachusetts that are not currently under construction. The impairments include amounts paid for the purchase of four turbines related to these development projects. We decided to terminate our development projects due to the expected excess generation capacity in most domestic markets and the significant decline in the forward market prices of electricity. In accordance with the provisions of APB No. 18, we recognized $6.1 million for an other than temporary decline in the value of our investment in a waste burning power plant in Michigan where operating cash flows are not sufficient to pay existing debt service and we are not likely to recover our equity interest in this investment.

Reduction of Financial Investment

Our financial investments business recorded a $4.6 million reduction of its investment in a leased aircraft due to the other than temporary decline in the estimated residual value of used airplanes as a result of the September 11, 2001 terrorist attacks and the general downturn in the aviation industry. This investment is accounted for as a leveraged lease under SFAS No. 13, *Accounting for Leases.*

2000 Events

In 2000, BGE offered a targeted VSERP to employees ages 55 or older with 10 or more years of service in targeted positions that elected to retire on June 1, 2000 to reduce our operating costs to become more competitive. BGE recorded approximately $10.0 million pre-tax for employees that elected to participate in the program. Of this amount, BGE recorded approximately $3.0 million on its balance sheet as a regulatory asset of its gas business. BGE is amortizing this regulatory asset over a 5-year period as provided by the June 2000 Maryland PSC gas base rate order as discussed in Note 6 on page 71. The remaining $7.0 million, or $4.2 million after-tax, related to BGE's electric business and was charged to expense.

1999 Events

Our generation operation recorded a $21.4 million pre-tax, or $14.2 million after-tax, impairment of two geothermal power projects. These impairments 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, we experienced a declining water temperature of the geothermal resource used by one of the plants for production.

Our Latin American operation recorded a $7.1 million pre-tax, or $4.5 million after-tax, impairment to reflect the fair value of our investment in a generating company in Bolivia as a result of our international exit strategy at that time to focus on our core businesses.

Our financial investments exchanged its shares of common stock in Capital Re, an insurance company, for common stock of ACE Limited (ACE) as part of a business combination whereby ACE acquired 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 $26.2 million pre-tax, or $16.0 million after-tax, to reflect the closing price of the business combination.

Our real estate and senior-living facilities operations 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. However, our real estate and senior-living operations recorded a $9.6 million pre-tax, or $5.8 million after-tax, impairment related to the proposed sale of these facilities.

Note 3. Information by Operating Segment

Our reportable operating segments are—Merchant Energy, Regulated Electric, and Regulated Gas:

- Our nonregulated merchant energy business in North America:
  - provides power marketing, origination transactions, and risk management services,
  - develops, owns, and operates generating facilities and/or power projects in North America, and
  - provides nuclear consulting services.
- Our regulated electric business purchases, distributes, and sells electricity in Maryland.
- Our regulated gas business purchases, transports, and sells natural gas in Maryland.

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

Effective July 1, 2000, the financial results of the electric generation portion of our business are included in the merchant energy business segment. Prior to that date, the financial results of electric generation are included in our regulated electric business.

Our remaining nonregulated businesses:

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

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.

	Merchant Energy Business	Regulated Electric Business	Regulated Gas Business	Other Nonregulated Businesses	Unallocated Corporate Items and Eliminations	Consolidated
			(In millions)			
2001						
Unaffiliated revenues	$ 614.3	$2,039.6	$ 674.3	$ 600.1	$ –	$3,928.3
Intersegment revenues	1,151.2	0.4	6.4	2.0	(1,160.0)	–
Total revenues	1,765.5	2,040.0	680.7	602.1	(1,160.0)	3,928.3
Depreciation and amortization	174.9	173.3	47.7	23.2	–	419.1
Fixed charges	25.8	135.8	28.5	48.7	–	238.8
Income tax expense (benefit)	25.2	36.8	25.7	(49.8)	–	37.9
Cumulative effect of change in accounting principle	–	–	–	8.5	–	8.5
Net income (loss) (a)	93.1	50.9	37.5	(90.6)	–	90.9
Segment assets	8,134.3	3,764.9	1,104.2	1,314.0	(239.8)	14,077.6
Capital expenditures	1,815.0	180.3	58.7	35.0	–	2,089.0
2000						
Unaffiliated revenues	$ 421.1	$2,134.7	$ 603.8	$ 692.9	$ –	$3,852.5
Intersegment revenues	604.6	0.5	7.8	20.4	(633.3)	–
Total revenues	1,025.7	2,135.2	611.6	713.3	(633.3)	3,852.5
Depreciation and amortization	83.6	319.9	46.2	20.3	–	470.0
Equity in income of equity-method investees (b)	–	2.4	–	–	–	2.4
Fixed charges	18.3	168.4	27.3	65.8	(8.4)	271.4
Income tax expense	118.5	72.2	21.9	17.5	–	230.1
Net income (c)	198.6	102.3	30.6	13.8	–	345.3
Segment assets	7,295.5	3,392.3	1,089.9	1,491.5	(329.9)	12,939.3
Capital expenditures	699.0	290.3	59.7	131.5	–	1,180.5
1999						
Unaffiliated revenues	$ 277.3	$2,258.8	$ 476.5	$ 828.3	$ –	$3,840.9
Intersegment revenues	–	1.2	11.6	20.1	(32.9)	–
Total revenues	277.3	2,260.0	488.1	848.4	(32.9)	3,840.9
Depreciation and amortization	7.5	376.4	44.9	21.0	–	449.8
Equity in income of equity-method investees (b)	–	5.1	–	–	–	5.1
Fixed charges	–	174.2	26.1	56.1	(1.4)	255.0
Income tax expense (benefit)	29.2	149.2	18.1	(10.1)	–	186.4
Extraordinary loss	–	66.3	–	–	–	66.3
Net income (loss) (d)	52.4	198.8	33.0	(24.1)	–	260.1
Segment assets	1,259.0	6,312.6	915.3	1,239.7	18.5	9,745.1
Capital expenditures	163.0	366.8	69.2	115.2	–	714.2

(a) Our merchant energy business, our regulated electric business, our regulated gas business, and our other nonregulated businesses recognized $198.1 million, $33.6 million, $0.8 million, and $102.3 million, respectively, for workforce reduction costs, contract termination related costs, and impairment losses and other costs as described more fully in Note 2.

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

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

(d) Our regulated electric business recorded expense of $4.9 million related to Hurricane Floyd. Our merchant energy business recorded $14.2 million for the impairment of two geothermal power plants. Our Latin American operation recorded $4.5 million for the impairment to reflect the fair value of our investment in a power project in Bolivia. Our financial investments operation recorded $16.0 million for the reduction 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 impairment of certain senior-living facilities.

Note 4. Investments

Real Estate Projects and Investments

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

	2001	2000
	(In millions)	
Properties under development	**$100.5**	$165.1
Operating properties		
(net of accumulated depreciation)	**0.9**	12.7
Equity interest in real estate investments	**109.3**	112.5
Total real estate projects and investments	**$210.7**	$290.3

See Note 2 on page 65 for a discussion of impairments in 2001.

Power Projects

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

At December 31,	2001	2000
	(In millions)	
Equity Method	**$480.3**	$488.4
Cost Method	**10.7**	10.8
Total power projects	**$491.0**	$499.2

Our percentage voting interest in power projects accounted for under the equity method ranges from 16% to 50%. Equity in earnings of these power projects were $24.2 million in 2001, $50.2 million in 2000, and $49.7 million in 1999.

Our power projects accounted for under the equity method include investments of $296.4 million in 2001 and $297.9 million in 2000 that sell electricity in California under power purchase agreements called "Interim Standard Offer No. 4" agreements. We discuss these projects further in Note 11 on page 83.

Our Latin American operation held power projects of $8.1 million at December 31, 2001 and $11.4 million at December 31, 2000.

See Note 2 on page 65 for a discussion of impairments recorded in 2001.

Orion and Financial Investments

Financial investments consist of the following:

At December 31,	2001	2000
	(In millions)	
Orion	**$442.5**	$192.0
Marketable equity securities	**20.2**	105.9
Financial limited partnerships	**25.8**	32.7
Leveraged leases	**14.7**	22.4
Total financial investments	**$503.2**	$353.0

Investments Classified as Available-for-Sale

We classify the following investments as available-for-sale:

- nuclear decommissioning trust funds,
- our other nonregulated businesses' marketable equity securities (shown above), and
- Orion.

This means we do not expect to hold them to maturity, and we do not consider them trading securities.

Effective June 1, 2001, we changed our accounting for the investment in Orion from the equity method to the cost method. This change resulted from no longer having significant influence as required under equity method accounting due to a reduction in our ownership percentage. Our ownership percentage decreased due to Orion's issuance of 13 million shares of common stock that were sold in a public offering and due to our sale of one million shares as part of the offering. At December 31, 2001, the unrealized gain on our investment in Orion was $244.0 million. In addition, at December 31, 2001, we owned a warrant for 705,900 shares of common stock in Orion with a fair market value of $11.8 million. These warrants are accounted for under SFAS No. 133 as discussed in Note 1 on page 63.

We show the fair values, gross unrealized gains and losses, and amortized cost bases for all of our available-for-sale securities, in the following tables. We use specific identification to determine cost in computing realized gains and losses, except we use average cost basis for our investment in Orion.

At December 31, 2001	Amortized Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value
		(In millions)		
Marketable equity securities	**$773.9**	**$270.6**	**$(10.3)**	**$1,034.2**
Corporate debt and				
U.S. Government agency	**47.7**	**1.5**	**–**	**49.2**
State municipal bonds	**38.4**	**3.3**	**(0.2)**	**41.5**
Totals	**$860.0**	**$275.4**	**$(10.5)**	**$1,124.9**

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

In addition to the above securities, the nuclear decommissioning trust funds included $7.7 million at December 31, 2001 and $6.8 million at December 31, 2000 of cash and cash equivalents.

The preceding tables include $21.0 million in 2001 and $34.7 million in 2000 of unrealized net gains associated with the nuclear decommissioning trust funds that are reflected as a change in the nuclear decommissioning trust funds in our Consolidated Balance Sheets.

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

	2001	2000	1999
		(In millions)	
Gross realized gains	**$47.6**	$54.5	$ 11.7
Gross realized losses	**(7.9)**	(8.0)	(38.8)
Net realized gains (losses)	**$39.7**	$46.5	$(27.1)

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

At December 31, 2001	Amount
	(In millions)
Less than 1 year	$ 8.4
1-5 years	34.3
5-10 years	22.2
More than 10 years	25.8
Total maturities of debt securities	$90.7

Note 5. 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 provided 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 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 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 ends in 2004 to 2006.
- BGE's electric fuel rate clause was discontinued effective July 1, 2000.
- Electric delivery service rates are frozen through June 2004 for commercial and industrial customers. The generation and transmission components of rates are frozen for different time periods depending on the service options selected by those customers.
- BGE collects $528 million after-tax of its potentially stranded investments and utility restructuring costs through a competitive transition charge on its customers' bills. Residential customers will pay this charge through 2006. Commercial and industrial customers will pay in a lump sum or over a period ending in 2004 to 2006, 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 on page 57, 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 6 on page 71.

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 reduced its book value.

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 the 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 related to Calvert Cliffs. However, BGE recognized after-tax impairment losses totaling $115.8 million associated with certain of its 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, BGE 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, BGE 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.

BGE 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.

Note 6. Regulatory Assets (net)

As discussed in Note 1 on page 57, 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,	2001	2000
	(In millions)	
Electric generation-related regulatory asset	**$249.0**	$267.8
Income taxes recoverable through future rates (net)	**95.6**	101.2
Deferred postretirement and postemployment benefit costs	**35.5**	38.7
Deferred environmental costs	**26.0**	28.8
Deferred fuel costs (net)	**33.5**	71.1
Workforce reduction costs	**21.6**	2.8
Other (net)	**2.6**	4.5
Total regulatory assets (net)	**$463.8**	$514.9

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 on page 60, income taxes recoverable through future rates are the portion of our net deferred income tax liability that is applicable to our regulated utility business, but has not been reflected in the rates we charge our customers. These income taxes represent the tax effect of temporary differences in depreciation and the allowance for equity funds used during construction, offset by differences in deferred tax rates and deferred taxes on deferred investment tax credits. We amortize these amounts as the temporary differences reverse.

Deferred Postretirement and Postemployment Benefit Costs

Deferred postretirement and postemployment benefit costs are the costs we recorded under SFAS No. 106 (for postretirement benefits) and No. 112 (for postemployment benefits) in excess of the costs we included in the rates we charge our customers. We began amortizing these costs over a 15-year period in 1998. We discuss these costs further in Note 7 on page 72.

Deferred Environmental Costs

Deferred environmental costs are the estimated costs of investigating and cleaning up contaminated sites we own. We discuss this further in Note 11 on page 80. We are amortizing $21.6 million of these costs (the amount we had incurred through October 1995) and $6.4 million of these costs (the amount we incurred from November 1995 through June 2000) over 10-year periods in accordance with the Maryland PSC's orders.

Deferred Fuel Costs

As described in Note 1 on page 58, 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,	2001	2000
	(In millions)	
Electric	**$ –**	$42.3
Gas	**33.5**	28.8
Deferred fuel costs (net)	**$33.5**	$71.1

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 collected this accumulated difference from customers over the twelve-month period ending October 2001.

Workforce Reduction Costs

The portions of the workforce reduction costs associated with the VSERP and involuntary severance programs we announced in 2001 and 2000 that relate to BGE's gas business are deferred as regulatory assets in accordance with the Maryland PSC's orders in prior rate cases. These costs are amortized over 5-year periods. See Note 2 on page 64 and Note 7 on page 72.

Note 7. Pension, Postretirement, Other Postemployment, and Employee Savings Plan Benefits

We offer pension, postretirement, other postemployment, and employee savings plan benefits. We describe each of these separately below. Nine Mile Point offers its own pension, postretirement, other postemployment, and employee savings plan benefits to its employees. The benefits for Nine Mile Point are included in the tables beginning on the next page.

Pension Benefits

We sponsor several defined benefit pension plans for our employees. These include the basic, qualified plan that most employees participate in and several nonqualified plans that are available only to certain employees. A defined benefit plan specifies the amount of benefits a plan participant is to receive using information about the participant. Employees do not contribute to these plans. Generally, we calculate the benefits under these plans based on age, years of service, and pay.

Sometimes we amend the plans retroactively. These retroactive plan amendments require us to recalculate benefits related to participants' past service. We amortize the change in the benefit costs from these plan amendments on a straight-line basis over the average remaining service period of active employees.

We fund the plans by contributing at least the minimum amount required under Internal Revenue Service regulations. We calculate the amount of funding using an actuarial method called the projected unit credit cost method. The assets in all of the plans at December 31, 2001 were mostly marketable equity and fixed income securities.

In 1999, we made 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.

Postretirement Benefits

We sponsor defined benefit postretirement health care and life insurance plans that cover substantially all of our employees. Generally, we calculate the benefits under these plans based on age, years of service, and pension benefit levels. We do not fund these plans.

For nearly all of the health care plans, retirees make contributions to cover a portion of the plan costs.

Contributions for employees who retire after June 30, 1992 are calculated based on age and years of service. The amount of retiree contributions increases based on expected increases in medical costs. For the life insurance plan, retirees do not make contributions to cover a portion of the plan costs.

Effective January 1, 1993, we adopted SFAS No. 106, *Employers' Accounting for Postretirement Benefits Other Than 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 6 on page 71), 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.

VSERP

In 2001, our Board of Directors approved several voluntary retirement programs for Constellation Energy and certain subsidiaries. The first group of these programs offered enhanced early retirement benefits to employees age 55 or older with 10 or more years of service. The second group of these programs offered enhanced early retirement benefits to employees age 50 to 54 with 20 or more years of service.

Since employees electing to participate in the age 55 or older VSERP had to make their elections by the end of 2001, the cost of that program was reflected in 2001. The total cost of that program was approximately $83.8 million ($63.5 million in pension termination benefits, $18.5 million in postretirement benefit costs, and $1.8 million in education and outplacement assistance costs). Of this amount, BGE recorded approximately $13.7 million on its balance sheet as a regulatory asset of its gas business. This amount will be amortized over a 5-year period as provided for in prior Maryland PSC rate orders.

In connection with the retirement of a significant number of the participants in the nonqualified pension plans we recognized a settlement loss of approximately $10.5 million and a curtailment loss of approximately $5.8 million for those plans in accordance with SFAS No. 88.

Since the age 50 to 54 programs allow employees to make their elections beginning in January through February 2002, the cost of that program will be reflected in 2002.

We recorded a $133.0 million additional minimum pension liability adjustment as a result of the combination of decreases in the fair value of plan assets due to a declining equity market in 2001 and an increased pension liability primarily due to the VSERP. We charged $59.0 million of this adjustment to an intangible asset included in "Other deferred charges" in our Consolidated Balance Sheets. The remaining $74.0 million, or $44.7 million after-tax, of this adjustment was included in "Accumulated other comprehensive income" in our Consolidated Statements of Common Shareholders' Equity and Consolidated Statements of Capitalization.

In 2000, we offered a targeted VSERP to provide enhanced early retirement benefits to certain eligible participants in targeted jobs at BGE that elected to retire on June 1, 2000. BGE recorded approximately $10.0 million ($7.6 million for pension termination benefits and $2.4 million for postretirement benefit costs) for employees that elected to participate in the program. Of this amount, BGE recorded approximately $3.0 million on its balance sheet as a regulatory asset of its gas business. We amortize this regulatory asset over a 5-year period. The remaining $7.0 million related to BGE's electric business was charged to expense.

The cost of the 2001 and 2000 voluntary retirement programs and the settlement or curtailment losses are not included in the tables of net periodic pension and postretirement benefit costs.

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 including the effect of the Nine Mile Point acquisition, in the following tables.

	Pension Benefits		Postretirement Benefits	
	2001	2000	**2001**	2000
	(In millions)			
Change in benefit obligation				
Benefit obligation at January 1	**$1,045.1**	$1,016.7	**$375.9**	$358.7
Service cost	**25.8**	25.4	**8.4**	7.7
Interest cost	**76.1**	73.1	**29.2**	26.6
Plan participants' contributions	**–**	–	**3.0**	2.8
Actuarial loss	**42.6**	0.8	**49.1**	40.9
Plan amendments	**–**	6.7	**–**	(41.1)
VSERP charge	**63.5**	7.6	**18.5**	2.4
Curtailment	**9.7**	–	**–**	–
Settlement	**(23.0)**	–	**–**	–
Nine Mile Point acquisition	**91.8**	–	**15.0**	–
Benefits paid	**(72.4)**	(85.2)	**(23.9)**	(22.1)
Benefit obligation at December 31	**$1,259.2**	$1,045.1	**$475.2**	$375.9

	Pension Benefits		Postretirement Benefits	
	2001	2000	**2001**	2000
	(In millions)			
Change in plan assets				
Fair value of plan assets at January 1	**$1,030.1**	$1,084.9	**$ –**	$ –
Actual return on plan assets	**(42.7)**	3.7	**–**	–
Employer contribution	**39.4**	26.7	**20.9**	19.3
Plan participants' contributions	**–**	–	**3.0**	2.8
Benefits paid	**(72.4)**	(85.2)	**(23.9)**	(22.1)
Fair value of plan assets at December 31	**$ 954.4**	$1,030.1	**$ –**	$ –

	Pension Benefits		Postretirement Benefits	
	2001	2000	**2001**	2000
	(In millions)			
Funded Status				
Funded Status at December 31	**$(304.8)**	$(15.0)	**$(475.2)**	$(375.9)
Unrecognized net actuarial loss	**207.8**	49.2	**107.8**	61.4
Unrecognized prior service cost	**56.7**	59.2	**(0.4)**	(0.4)
Unrecognized transition obligation	**–**	–	**86.9**	94.8
Unamortized net asset from adoption of SFAS No. 87	**–**	(0.2)	**–**	–
Pension liability adjustment	**(133.0)**	–	**–**	–
(Accrued) prepaid benefit cost	**$(173.3)**	$ 93.2	**$(280.9)**	$(220.1)

Net Periodic Benefit Cost

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

Year Ended December 31,	2001	2000	1999
		(In millions)	
Components of net periodic pension benefit cost			
Service cost	**$25.8**	$25.4	$26.1
Interest cost	**76.1**	73.1	65.3
Expected return on plan assets	**(87.5)**	(83.6)	(76.6)
Amortization of transition obligation	**(0.2)**	(0.2)	(0.2)
Amortization of prior service cost	**6.5**	6.5	2.5
Recognized net actuarial loss	**2.8**	2.6	10.1
Amount capitalized as construction cost	**(2.5)**	(3.4)	(4.2)
Net periodic pension benefit cost	**$21.0**	$20.4	$23.0

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

Year Ended December 31,	2001	2000	1999
		(In millions)	
Components of net periodic postretirement benefit cost			
Service cost	**$ 8.4**	$ 7.7	$ 8.6
Interest cost	**29.2**	26.6	24.4
Amortization of transition obligation	**7.9**	7.9	11.0
Recognized net actuarial loss	**3.3**	3.1	1.9
Amount capitalized as construction cost	**(14.5)**	(10.8)	(9.4)
Net periodic postretirement benefit cost	**$34.3**	$34.5	$36.5

Assumptions

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

	Pension Benefits		Postretirement Benefits	
At December 31,	2001	2000	2001	2000
Discount rate	**7.25%**	7.50%	**7.25%**	7.50%
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 2001, 5.7% for Medicare-eligible retirees and 9.5% for retirees not covered by Medicare, and
- in 2002, 11.0% for both Medicare-eligible retirees and retirees not covered by Medicare.

After 2002, we assumed inflation rates will decrease to 7.0% in 2003, 6.5% in 2004, 6.0% in 2005, and 5.5% annually after 2005.

A one-percent increase in the health care inflation rate from the assumed rates would increase the accumulated postretirement benefit obligation by approximately $63.8 million as of December 31, 2001 and would increase the combined service and interest costs of the postretirement benefit cost by approximately $5.9 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 $51.1 million as of December 31, 2001 and would decrease the combined service and interest costs of the postretirement benefit cost by approximately $4.7 million annually.

Other Postemployment Benefits

We provide the following postemployment benefits:

- health and life insurance benefits to eligible employees 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 $48.7 million as of December 31, 2001 and $46.7 million as of December 31, 2000.

Effective December 31, 1993, we adopted SFAS No. 112, *Employers' Accounting for Postemployment Benefits.* We deferred, as a regulatory asset (see Note 6 on page 71), 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 5.0% in 2001 and 5.5% in 2000.

Employee Savings Plan Benefits

We, along with several of our subsidiaries, sponsor defined contribution savings plans that are offered to all eligible employees of Constellation Energy and certain employees of our subsidiaries. The Savings Plans are qualified 401(k) plans under the Internal Revenue Code. In a defined contribution plan, the benefits a participant is to receive result from regular contributions to a participant account. Matching contributions to participant accounts are made under these plans. Matching contributions to these plans were:

- $12.2 million in 2001,
- $10.8 million in 2000, and
- $10.4 million in 1999.

Note 8. 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

In anticipation of separating our merchant energy business from our other businesses and to fund working capital requirements and capital expenditures, in June 2001, Constellation Energy arranged a $2.5 billion, 364-day revolving credit facility. However, since we canceled prior plans to separate, we used this facility primarily to fund capital expenditures, and working capital requirements, including commercial paper support, for the merchant energy business.

In June 2001, Constellation Energy also arranged a $380 million, 364-day revolving credit facility to be used primarily to support letters of credit and for other short-term financing needs, including commercial paper support. Constellation Energy also has an existing $188.5 million, multi-year revolving credit facility available for short-term and long-term needs, including support for the issuance of letters of credit.

Constellation Energy had committed bank lines of credit as described above of $3.1 billion at December 31, 2001 and $565.0 million at December 31, 2000 for short-term financial needs, including support for the issuance of letters of credit. These agreements also support Constellation Energy's commercial paper program. Letters of credit issued under all of our facilities totaled $245.8 million at December 31, 2001 and $297.2 million at December 31, 2000. Constellation Energy had commercial paper outstanding of $954.9 million at December 31, 2001 and $198.7 million at December 31, 2000.

The weighted-average effective interest rates for Constellation Energy's commercial paper were 3.73% for the year ended December 31, 2001 and 6.31% for 2000.

BGE

BGE had no commercial paper outstanding at December 31, 2001 and $32.1 million at December 31, 2000.

At December 31, 2001, BGE had unused committed bank lines of credit totaling $243.0 million supporting the commercial paper program compared to $218.0 million at December 31, 2000. BGE has a $25 million revolving credit agreement that is available through 2003. At December 31, 2001 and 2000, BGE did not have any borrowings under the revolving credit agreement. This agreement also supports BGE's commercial paper program.

The weighted-average effective interest rates for BGE's commercial paper were 2.53% for the year ended December 31, 2001 and 6.36% for 2000.

Other Nonregulated Businesses

Our other nonregulated businesses had short-term borrowings outstanding of $20.1 million at December 31, 2001 and $12.8 million at December 31, 2000. The weighted-average effective interest rates for our other nonregulated businesses' short-term borrowings were 4.20% for the year ended December 31, 2001 and 8.59% for 2000.

Note 9. 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

On January 17, 2001, we issued $400.0 million of Mandatorily Redeemable Floating Rate Notes that matured on January 17, 2002.

On April 11, 2001, we issued $235.0 million of Mandatorily Redeemable Floating Rate Notes that matured on January 17, 2002.

In 2001, we redeemed several Notes that totaled $700.0 million prior to their maturity for a purchase price equal to 100% of their principal amount, plus accrued interest.

BGE

BGE's First Refunding Mortgage Bonds

BGE's first refunding mortgage bonds are secured by a mortgage lien on all of its assets. The generating assets BGE transferred to subsidiaries of Constellation Energy also remain subject to the lien of BGE's mortgage, along with the stock of Safe Harbor Water Power Corporation and Constellation Enterprises, Inc.

BGE is required to make an annual sinking fund payment each August 1 to the mortgage trustee. The amount of the payment is equal to 1% of the highest principal amount of bonds outstanding during the preceding 12 months. The trustee uses these funds to retire bonds from any series through repurchases or calls for early redemption. However, the trustee cannot call the following bonds for early redemption:

- 7¼% Series, due 2002
- 6½% Series, due 2003
- 6⅛% Series, due 2003
- 5½% Series, due 2004
- 7½% Series, due 2007
- 6⅝% 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 May 11, 2001, BGE issued $200.0 million of Floating Rate Reset Notes that matured on February 5, 2002.

Also on May 11, 2001, BGE redeemed $200.0 million of Floating Rate Notes.

On December 11, 2001, BGE issued $300.0 million 5.25% Notes, due December 15, 2006.

On July 1, 2000, BGE transferred $278.0 million of tax-exempt debt to our merchant energy business related to the transferred assets. At December 31, 2001, BGE remains contingently liable for the $276.5 million outstanding balance of this debt.

On December 20, 2000, BGE issued $173.0 million of 6.75% Remarketable and Redeemable Securities (ROARS) due December 15, 2012. 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, 2001 in the following table.

Series	Weighted-Average Interest Rate	Maturity Dates
B	8.77%	2002-2006
C	7.97	2003
D	6.67	2004-2006
E	6.66	2006-2012
G	6.08	2008

Some of the medium-term notes include a "put option." These put options allow the holders to sell their notes back to BGE on the put option dates at a price equal to 100% of the principal amount. The following is a summary of medium-term notes with put options.

Series E Notes	Principal	Put Option Dates
	(In millions)	
6.75%, due 2012	$60.0	June 2002 and 2007
6.75%, due 2012	$25.0	June 2004 and 2007
6.73%, due 2012	$25.0	June 2004 and 2007

BGE Obligated Mandatorily Redeemable Trust Preferred Securities
On June 15, 1998, BGE Capital Trust I (Trust), a Delaware business trust established by BGE, issued 10,000,000 Trust Originated Preferred Securities (TOPrS) for $250 million ($25 liquidation amount per preferred security) with a distribution rate of 7.16%.

The Trust used the net proceeds from the issuance of the common securities and the preferred securities to purchase a series of 7.16% Deferrable Interest Subordinated Debentures due June 30, 2038 (debentures) from BGE in the aggregate principal amount of $257.7 million with the same terms as the TOPrS. The Trust must redeem the TOPrS at $25 per preferred security plus accrued but unpaid distributions when the debentures are paid at maturity or upon any earlier redemption. BGE has the option to redeem the debentures at any time on or after June 15, 2003 or at any time when certain tax or other events occur.

The interest paid on the debentures, which the Trust will use to make distributions on the TOPrS, is included in "Interest expense" in our Consolidated Statements of Income and is deductible for income tax purposes.

BGE fully and unconditionally guarantees the TOPrS based on its various obligations relating to the trust agreement, indentures, debentures, and the preferred security guarantee agreement.

The debentures are the only assets of the Trust. The Trust is wholly owned by BGE because it owns all the common securities of the Trust that have general voting power.

For the payment of dividends and in the event of liquidation of BGE, the debentures are ranked prior to preference stock and common stock.

Other Nonregulated Businesses
Revolving Credit Agreement
ComfortLink has a $50 million unsecured revolving credit agreement that matures September 26, 2002. 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 $46.0 million at December 31, 2001 and $34.0 million at December 31, 2000.

On December 18, 2001, ComfortLink entered into a $25.0 million loan agreement with the Maryland Energy Financing Administration (MEFA). The terms of the loan exactly match the terms of variable rate, tax exempt bonds due December 1, 2031 issued by MEFA for ComfortLink to finance the cost of building a chilled water distribution system. The interest rate on this debt resets weekly. These bonds, and the corresponding loan, can be redeemed at any time at par plus accrued interest while under variable rates. The bonds can also be converted to a fixed rate at ComfortLink's option.

Mortgage and Construction Loans

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

- 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.

Maturities of Long-Term Debt

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

Year	Constellation Energy	Nonregulated Business	BGE
		(In millions)	
2002	$635.0	$ 85.4	$ 519.8
2003	–	86.1	285.6
2004	–	83.7	155.4
2005	300.0	78.4	46.9
2006	–	78.4	464.9
Thereafter	–	357.1	947.7
Total long-term debt at December 31, 2001	$935.0	$769.1	$2,420.3

At December 31, 2001, 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") which contain certain put options under which lenders could potentially require us to repay the debt prior to maturity. Of this amount, $171.5 million could be repaid in 2002 and $50.0 million in 2004. At December 31, 2001, $146.5 million is classified as current portion of long-term debt as a result of these provisions.

At December 31, 2001, our other nonregulated businesses had long-term loans totaling $20.0 million that mature after 2003 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,	**2001**	2000
Nonregulated Businesses (including Constellation Energy)		
Floating rate notes	**4.95%**	6.98%
Loans under credit agreements	**4.60**	6.64
Mortgage and construction loans	**4.39**	7.78
Tax-exempt debt transferred from BGE	**3.12**	4.26
Other tax-exempt debt	**1.75**	–
BGE		
Remarketed floating rate series mortgage bonds	**4.49%**	6.59%
Floating rate reset notes	**4.14**	7.27
Medium-term notes, Series G	–	6.58
Medium-term notes, Series H	–	6.58

Note 10. Leases

There are two types of leases—operating and capital. Capital leases qualify as sales or purchases of property and are reported in our Consolidated Balance Sheets. Capital leases are not material in amount. All other leases are operating leases and are reported in our Consolidated Statements of Income. We expense all lease payments associated with our regulated utility operations. We present information about our operating leases below.

Outgoing Lease Payments

We, as lessee, lease some facilities and equipment. The lease agreements expire on various dates and have various renewal options.

Lease expense was:

- $11.7 million in 2001,
- $11.3 million in 2000, and
- $12.2 million in 1999.

At December 31, 2001, we owed future minimum payments for long-term, noncancelable, operating leases as follows:

Year	
	(In millions)
2002	$ 9.1
2003	24.1
2004	39.2
2005	37.9
2006	13.3
Thereafter	145.8
Total future minimum lease payments	$269.4

The above table includes the operating lease payments for the High Desert project in California through 2006. We are currently leasing and supervising the construction of the High Desert project, a 750 megawatt generating facility in California. The High Desert project uses an off-balance sheet financing structure through a special-purpose entity (SPE) that qualifies as an operating lease. The project is scheduled for completion in the summer of 2003.

Under the terms of the lease, we are required to make payments that represent all or a portion of the lease balance if one of the following events occurs: termination of construction prior to completion or our default under the lease.

In addition, we may be required to either post cash collateral equal to the outstanding lease balance or we may elect to purchase the property for the outstanding lease balance. At any time during the term of the lease we have the right to pay off the lease and acquire the asset from the lessor. At December 31, 2001, the outstanding lease balance plus other committed expenses was $271.2 million.

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

- renew the lease upon approval of the lessors,
- elect to purchase the property for a price equal to the lease balance at the end of the term, or
- request the lessor to sell the property.

If we request the lessor to sell the property, we guarantee the sale proceeds up to approximately 83% of the lease balance. The lease balance at the end of the term is currently estimated to be $600 million, which represents the estimated cost of the project; however, this may vary based on the ultimate cost of construction and interest incurred during the construction period.

Note 11. Commitments, Guarantees, and Contingencies

Commitments

We have made substantial commitments in connection with our merchant energy, regulated gas, and other nonregulated business. These commitments relate to:

- purchase of electric generating capacity and energy,
- procurement and delivery of fuels, and
- capital for construction programs and loans.

Our merchant energy business has a long-term contract for the purchase of electric generating capacity and energy that expires in 2013. Portions of this contract became uneconomical upon the deregulation of electric generation. Therefore, we recorded a charge and accrued a corresponding liability based on the net present value of the excess of estimated contract costs over the market-based revenues to recover these costs over the remaining term of the contract as discussed in Note 5 on page 70. At December 31, 2001, the accrued portion of this contract was $10.6 million.

Our merchant energy business enters into various long-term contracts for the procurement and delivery of fuels to supply our generating plant requirements. In most cases, our contracts contain provisions for price escalations, minimum purchase levels, and other financial commitments. These contracts expire in various years between 2002 and 2006. In addition, our merchant energy business enters into long-term contracts for the capacity and transmission rights for the delivery of energy to meet our physical obligations to our customers. These contracts expire in various years between 2002 and 2021.

Our merchant energy business also has committed to contribute additional capital for our construction program and to make additional loans to some affiliates, joint ventures, and partnerships in which they have an interest.

At December 31, 2001, we estimate the future obligations of our merchant energy business in the following table:

	2002	2003	2004	2005	2006	Thereafter	Total
				(In millions)			
Purchased capacity and energy	$ 16.4	$ 16.0	$ 15.5	$15.1	$15.0	$ 98.5	$ 176.5
Fuel and transportation	318.1	228.3	99.5	49.1	48.8	17.7	761.5
Capital and loans	81.5	0.8	–	–	–	–	82.3
Total future obligations	$416.0	$245.1	$115.0	$64.2	$63.8	$116.2	$1,020.3

Our regulated gas business enters into various long-term contracts for the procurement, transportation, and storage of gas. These contracts are recoverable under BGE's gas cost adjustment clause discussed in Note 1 on page 58.

BGE Home Products & Services has gas purchase commitments of $35.0 million in 2002 and $2.2 million in 2003 related to its gas program.

Sale of Receivables

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 $25 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 these entities. BGE and BGE Home Products

& Services have recorded reserves for credit losses. At December 31, 2001, BGE had sold $8.1 million and BGE Home Products & Services had sold $42.5 million of receivables under these agreements.

Guarantees

At December 31, 2001, Constellation Energy issued guarantees in an amount up to $1,682.4 million related to credit facilities and contractual performance of certain of its nonregulated subsidiaries, including $600 million relating to the High Desert project. The actual subsidiary liabilities related to these guarantees totaled $369.9 million at December 31, 2001.

At December 31, 2001, Constellation Nuclear guaranteed the $388.1 million sellers' note that financed the acquisition of Nine Mile Point. This guarantee contains covenant provisions that require Constellation Nuclear to maintain a net worth of at least $500 million and a ratio of current assets to current liabilities of at least 1.1.

At December 31, 2001, our merchant energy business had other guaranteed outstanding loans and letters of credit of certain power projects totaling $26.7 million.

At December 31, 2001, our other nonregulated businesses had guaranteed outstanding loans and letters of credit of real estate projects totaling $15.9 million.

BGE guarantees two-thirds of certain debt of Safe Harbor Water Power Corporation. At December 31, 2001, Safe Harbor Water Power Corporation had outstanding debt of $20 million. The maximum amount of BGE's guarantee is $13.3 million. Additionally at December 31, 2001, BGE guaranteed the TOPrS of $250.0 million as discussed in Note 9 on page 76.

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.

The development (involving site selection, environmental assessments, and permitting), construction, acquisition, and operation of electric generating, transmission, and distribution facilities are subject to extensive federal, state, and local environmental and land use laws and regulations. From the beginning phases of siting and developing, to the ongoing operation of existing or new electric generating, transmission, and distribution facilities, our activities involve compliance with diverse laws and regulations that address emissions and impacts to air and water, special, protected, and cultural resources (such as wetlands, endangered species, and archeological/historical resources), chemical and waste handling, and noise impacts. Our activities require complex and often lengthy processes to obtain approvals, permits, or licenses for new, existing, or modified facilities. Additionally, the use and handling of various chemicals or hazardous materials (including wastes) requires preparation of release prevention plans and emergency response procedures. As new laws or regulations are promulgated, we assess their applicability and implement the necessary modifications to our facilities or their operation, as required.

We discuss the significant matters below.

Clean Air Act

The Clean Air Act affects both existing generating facilities and new projects. The Clean Air Act and many state laws require significant reductions in SO_2 (sulfur dioxide) and NO_x (nitrogen oxide) emissions that result from burning fossil fuels. The Clean Air Act also contains other provisions that could materially affect some of our projects. Various provisions may require permits, inspections, or installation of additional pollution control technology. Certain of these provisions are described in more detail below. Since our generation portfolio is diverse, both in the mix of fuels used to generate electricity, as well as in the age of various facilities, the Clean Air Act requirements have different impacts in terms of compliance costs for each of our projects. Many of these compliance costs may be substantial, as described in more detail below. In addition, the Clean Air Act contains many enforcement tools, ranging from broad investigatory powers to civil, criminal, and administrative penalties and citizen suits. These enforcement provisions also include enhanced monitoring, recordkeeping, and reporting requirements for both existing and new facilities.

The Clean Air Act creates a marketable commodity called an SO_2 "allowance." All non-exempt facilities over 25 megawatts that emit SO_2 must obtain allowances in order to operate after 1999. Each allowance gives the owner the right to emit one ton of SO_2. All non-exempt existing facilities have been allocated allowances based on a facility's past production and the statutory emission reduction goals. If additional allowances are needed for new facilities, they can be purchased from facilities having excess allowances or from SO_2 allowance banks. Our projects comply with the SO_2 allowance caps through the purchase of allowances, use of emission control devices, or by qualifying for exemptions. We believe that the additional costs of obtaining allowances needed for future generation projects should not materially affect our ability to build, acquire, and operate them.

The Clean Air Act also requires states to impose annual operating permit fees. These fees are based on the tons of pollutants emitted from a generating facility and vary based on the type of facility. For example, fees will typically be greater for coal-fired plants than for natural gas-fired plants. Our portfolio includes coal-fired plants and gas-fired plants, as well as plants using renewable energy sources such as solar and geothermal, which have far less emissions. The fees do not significantly increase our costs.

The Ozone Transport Assessment Group, composed of state and local air regulatory officials from the 37 Mid-Western and Eastern states, has recommended additional NOx emission reductions that go beyond current federal standards. These recommendations include reductions from utility and industrial boilers during the summer ozone season.

As a result of the Ozone Transport Assessment Group's recommendations, on October 27, 1998, the Environmental Protection Agency (EPA) issued a rule requiring 22 Eastern states and the District of Columbia to reduce emissions of NOx (a precursor of ozone). Among other things, the EPA's rule establishes an ozone season, which runs from May through September, and a NOx emission budget for each state, including Maryland and Pennsylvania. The EPA rule requires states to implement controls sufficient to meet their NOx budget by May 30, 2004. Coal-fired power plants are a principal target of NOx reductions under this initiative, however, some of our newer coal-fired plants may already meet the EPA expectations and will not require the same amount of capital expenditures.

Many of the generation facilities are subject to NOx reduction requirements under the EPA rule including those located in Maryland and Pennsylvania. This regulation affects both new and existing facilities causing additional capital investment. At the Brandon Shores facility we have installed and at our Wagner facility we are installing, emission reduction equipment by May 2002 to meet Maryland regulations issued pursuant to EPA's rule. The owners of the Keystone plant in Pennsylvania are installing emissions reduction equipment by 2003 to meet Pennsylvania regulations issued pursuant to EPA's rule. We estimate that the equipment needed at these plants will cost approximately $290 million. Through December 31, 2001, we have spent approximately $200 million.

Over the past two years, the EPA and several states have filed suits against a number of coal-fired power plants in Mid-Western and Southern states alleging violations of the deterioration prevention and non-attainment provisions of the Clean Air Act's new source review requirements. In 2000, using its broad investigatory powers, the EPA requested information relating to modifications made to our Brandon Shores, Crane, and Wagner plants in Baltimore, Maryland. The EPA also sent similar, but narrower, information requests to two of our newer Pennsylvania waste-coal burning plants. We have responded to the EPA and are waiting to see if the EPA takes any further action. 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. Although there have not been any new source review-related suits filed against our facilities, there can be no assurance that any of them will not be the target of an action in the future. Based on the levels of emissions control that the EPA and/or states are seeking in these new source review enforcement actions, we believe that material additional costs and penalties could be incurred, and/or planned capital expenditures could be accelerated, if the EPA was successful in any future actions regarding our facilities.

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

Future initiatives regarding greenhouse gas emissions and global warming continue to be the subject of much debate. The related Kyoto Protocol was signed by the United States but has not yet been ratified by the U.S. Senate. Future initiatives on this issue and the ultimate effects of the Kyoto Protocol on us are unknown at this time. As a result of our diverse fuel portfolio, our contribution to greenhouse gases varies. Fossil fuel-fired power plants, however, are significant sources of carbon dioxide emissions, a principal greenhouse gas. Therefore, our compliance costs with any mandated federal greenhouse gas reductions in the future could be significant.

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 Maryland Department of the Environment (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 6 on page 71. Through December 31, 2001, we have spent approximately $37 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.

California

Baldwin Associates, Inc. v. Gray Davis, Governor of California and 22 other defendants (including Constellation Power Development, Inc., a subsidiary of Constellation Power, Inc.) – This class action lawsuit was filed on October 5, 2001 in the Superior Court, County of San Francisco. The action seeks damages of $43 billion, recession and reformation of approximately 38 long-term power purchase contracts, and an injunction against improper spending by the state of California. Constellation Power Development, Inc. is named as a defendant but does not have a power purchase agreement with the State of California. However, our High Desert Power Project does have a power purchase agreement with the California Department of Water Resources. We believe this case is without merit. However, we cannot predict the timing, or outcome, of it or its possible effect on our financial results.

Employment Discrimination

Miller, et. al v. Baltimore Gas and Electric Company, et al. – This action was filed on September 20, 2000 in the U.S. District Court for the District of Maryland. Besides BGE, Constellation Energy Group, Constellation Nuclear, and Calvert Cliffs Nuclear Power Plant are also named defendants. The action seeks class certification for approximately 150 past and present employees and alleges racial discrimination at Calvert Cliffs Nuclear Power Plant. The amount of damages is unspecified, however the plaintiffs seek back and front pay, along with compensatory and punitive damages. The Court scheduled a briefing process for the motion to certify the case as a class action suit for the beginning of 2003. 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.

Asbestos

Since 1993, BGE has been involved in several actions concerning asbestos. The actions are based upon the theory of "premises liability," alleging that BGE knew of and exposed individuals to an asbestos hazard. The actions relate to two types of claims.

The first type is direct claims by individuals exposed to asbestos. BGE is involved in these claims with approximately 70 other defendants. Approximately 545 individuals that were never employees of BGE each claim $6 million in damages ($2 million compensatory and $4 million punitive). These claims were filed in the Circuit Court for Baltimore City, Maryland in the summer of 1993. BGE does not know the specific facts necessary to estimate its potential liability for these claims. The specific facts BGE does not know include:

- the identity of BGE's facilities at which the plaintiffs allegedly worked as contractors,
- the names of the plaintiff's employers, and
- the date on which the exposure allegedly occurred.

To date, 36 of these cases were settled for amounts that were not significant.

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

These claims relate to approximately 1,500 individual plaintiffs and were filed in the Circuit Court for Baltimore City, Maryland in the fall of 1993. To date, about 375 cases have been resolved, all without any payment by BGE. BGE does not know the specific facts necessary to estimate its potential liability for these claims. The specific facts we do not know include:

- the identity of BGE facilities containing asbestos manufactured by the manufacturer,
- the relationship (if any) of each of the individual plaintiffs to BGE,
- the settlement amounts for any individual plaintiffs who are shown to have had a relationship to BGE, and
- the dates on which/places at which the exposure allegedly occurred.

Until the relevant facts for both types of claims are determined, BGE is unable to estimate what its 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, the potential liability could be material.

Asset Transfer Order

On July 6, 2000, the Mid-Atlantic Power Supply Association (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. The Court of Special Appeals heard oral arguments on the appeal on September 7, 2001. We also believe that this petition is without merit. However, we cannot predict the timing or outcome of this case, which could have a material adverse effect on our, and BGE's, financial results.

Restructuring Order

In early December 1999, 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. The Court of Special Appeals heard oral arguments on the appeal on September 7, 2001. We believe that this petition is without merit. However, we cannot predict the timing or outcome of this case, which could have a material adverse effect on our, and BGE's, financial results.

Nuclear Insurance

We maintain nuclear insurance coverage for Calvert Cliffs and Nine Mile Point in four program areas: liability, worker radiation claims, property, and accidental outage. However, these policies have certain industry standard exclusions, such as ordinary wear and tear and war. Terrorist acts, while not excluded from the property and accidental outage policies, are covered as a common occurrence, meaning that if terrorist acts occur against one or more commercial nuclear power plants insured by our insurance company within a 12-month period, they will be treated as one event and the owners of the plants will share one full limit of each type of policy (currently $3.24 billion). Claims that arise out of terrorist acts are also covered by our nuclear liability and worker radiation policies. However, these policies are subject to one industry aggregate limit (currently $200 million) for the risk of terrorism. Unlike the property and accidental outage policies, however, an industry-wide retrospective assessment program applies above the industry limit (see below for an explanation of this program).

If there were an accident or an extended outage at any unit of Calvert Cliffs or Nine Mile Point, it could have a substantial adverse financial effect on us.

Liability Insurance

Pursuant to the Price-Anderson Act, we are required to insure against public liability claims resulting from nuclear incidents to the full limit of approximately $9.5 billion. We have purchased the maximum available commercial insurance of $200 million, and the remaining $9.3 billion is provided through mandatory participation in an industry-wide retrospective assessment program. Under this retrospective assessment program, we can be assessed up to $352.4 million per incident, payable at no more than $40 million per incident per year. This assessment also applies in excess of our worker radiation claims insurance and is subject to inflation and state premium taxes. In addition, the U.S. Congress could impose additional revenue-raising measures to pay claims.

Some of the provisions of this Act expire in August 2002, and the Act is subject to change if those provisions are extended. While we expect these provisions to be extended, we do not know what impact any changes to the Act may have on us.

Worker Radiation Claims Insurance

We participate in the American Nuclear Insurers Master Worker Program that provides coverage for worker tort claims filed for radiation injuries. Effective January 1, 1998, this program was modified to provide coverage to all workers whose nuclear-related employment began on or after the commencement date of reactor operations. Waiving the right to make additional claims under the old policy was a condition for acceptance under the new policy. We describe the old and new policies below:

- Nuclear worker claims reported on or after January 1, 1998 are covered by a new insurance policy with an annual industry aggregate limit of $200 million for radiation injury claims against all those insured by this policy.
- All nuclear worker claims reported prior to January 1, 1998 are still covered by the old policy. Insureds under the old policies, with no current operations, are not required to purchase the new policy described above, and may still

make claims against the old policies through 2007. If radiation injury claims under these old policies exceed the policy reserves, all policyholders could be retroactively assessed, with our share being up to $6.3 million.

The sellers of Nine Mile Point retain the liabilities for existing and potential claims that occurred prior to November 7, 2001. In addition, the Long Island Power Authority, which continues to own 18 percent of Unit 2 at Nine Mile Point, is obligated to assume its pro rata share of any liabilities for retrospective premiums and other premiums assessments. If claims under these policies exceed the coverage limits, the provisions of the Price-Anderson Act would apply.

Property Insurance

Our policies provide $500 million in primary and an additional $2.25 billion in excess coverage for property damage, decontamination, and premature decommissioning liability for Calvert Cliffs or Nine Mile Point. 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 $56.2 million.

Accidental Outage Insurance

Our policies provide indemnification on a weekly basis resulting from an accidental outage of a nuclear unit. Initial coverage begins after a 12-week deductible period and continues at 100% of the weekly indemnity limit for 52 weeks and 80% of the weekly indemnity limit for the next 110 weeks. Our coverage is up to $490.0 million per unit at Calvert Cliffs, $335.4 million for Unit 1 of Nine Mile Point, and $412.6 million for Unit 2 of Nine Mile Point. This amount can be reduced by up to $98.0 million per unit at Calvert Cliffs and $82.5 million for Nine Mile Point if an outage at either plant is caused by a single insured physical damage loss.

California Power Purchase Agreements

Our merchant energy business has $296.4 million invested in operating power projects of which our ownership percentage represents 146 megawatts of electricity that are sold to Pacific Gas & Electric (PGE) and to Southern California Edison (SCE) in California under power purchase agreements. Our merchant energy business was not paid in full for its sales from these plants to the two utilities from November 2000 through early April 2001. At December 31, 2001, our portion of the amount due for unpaid power sales from these utilities was approximately $45 million. We recorded reserves of approximately 20% of this amount.

These projects entered into agreements with PGE and SCE that provide for five-year fixed-price payments averaging $53.70 per megawatt-hour plus the stated capacity payments in the original Interim Standard Offer No. 4 (SO4) contracts. These agreements also provide for the payment of all past due amounts plus interest, which the projects expect to collect within the next two years. The SCE agreement to pay these past due amounts is contingent on SCE making certain payments to other creditors.

As a result of ongoing litigation before the FERC regarding sales into the spot markets of the California Independent System Operator and Power Exchange, we may be required to pay refunds of between $3 and $4 million for transactions that we entered into with these entities for the period between October 2000 and June 2001. While the process at FERC is ongoing, FERC has indicated that we will have the ability to reduce the potential refund amount in order to recover outstanding receivables we are owed. FERC also has indicated that it will consider adjustments to the refund amount to the extent we can demonstrate that its refund methodology resulted in an overall revenue shortfall for our transactions in these markets during the refund period.

Note 12. Risk Management Activities and Fair Value of Financial Instruments

Risk Management Activities

In 2001, we entered into forward starting interest rate swap contracts to manage a portion of our interest rate exposure for anticipated long-term borrowings to refinance our outstanding commercial paper obligations and maturing long-term debt. The swaps have notional or contract amounts that total $800 million with an average rate of 4.9% and expire in the first quarter of 2002. The notional amounts of the contracts do not represent amounts that are exchanged by the parties and are not a measure of our exposure to market or credit risks. The notional amounts are used in the determination of the cash settlements under the contracts. At December 31, 2001, the fair value of these swaps was an unrealized pre-tax gain of $36.3 million.

At December 31, 2001, these swaps were designated as cash-flow hedges under SFAS No. 133. We recorded this unrealized gain in "Other current assets" in our Consolidated Balance Sheets and "Accumulated other comprehensive income," net of associated deferred income tax effects, in our Consolidated Statements of Common Shareholders' Equity and Consolidated Statements of Capitalization. Any gain or loss on the hedges will be reclassified from "Accumulated other comprehensive income" into "Interest expense" and be included in earnings during the periods in which the interest payments being hedged occur.

In 2002, we entered into additional forward starting interest rate swaps with notional amounts that total $700 million. These swaps have an average rate of 5.9% and expire in the first quarter of 2002.

Our power marketing operation manages the commodity price risk of our electric generation operations as part of its overall portfolio. In order to manage this risk, our merchant energy business may enter into fixed-price derivative or non-derivative contracts to hedge the variability in future cash flows from forecasted sales of electricity and purchases of fuel as discussed in Note 1 on page 59.

At December 31, 2001, our merchant energy business had designated certain fixed-price forward electricity sale contracts as cash-flow hedges of forecasted sales of electricity for the years 2002 through 2010 under SFAS No. 133.

At December 31, 2001, our merchant energy business recorded net unrealized pre-tax gains of $76.5 million on these hedges, net of associated deferred income tax effects, in "Accumulated other comprehensive income." We expect to reclassify $5.7 million of net pre-tax gains on cash-flow hedges from "Accumulated other comprehensive income" into earnings during the next twelve months based on the market prices at December 31, 2001. However, the actual amount reclassified into earnings could vary from the amounts recorded at December 31, 2001 due to future changes in market prices. In 2001, there was no hedge ineffectiveness recognized in earnings.

At December 31, 2000, our merchant energy business recorded deferred pre-tax hedge losses of $58.3 million in "Other deferred charges" in our Consolidated Balance Sheets for the fixed-price forward electricity sale contracts designated as a hedge of forecasted sales of electricity. We reclassified these deferred hedge losses, net of associated deferred income tax effects, to "Accumulated other comprehensive income" upon the adoption of SFAS No. 133, in the first quarter of 2001.

Fair Value of Financial Instruments

The fair value of a financial instrument represents the amount at which the instrument could be exchanged in a current transaction between willing parties, other than in a forced sale or liquidation. Significant differences can occur between the fair value and carrying amount of financial instruments that are recorded at historical amounts. We use the following methods and assumptions for estimating fair value disclosures for financial instruments:

- cash and cash equivalents, net accounts receivable, other current assets, certain current liabilities, short-term borrowings, current portion of long-term debt, and certain deferred credits and other liabilities: because of their short-term nature, the amounts reported in our Consolidated Balance Sheets approximate fair value,
- investments and other assets where it was practicable to estimate fair value: the fair value is based on quoted market prices where available, and
- for long-term debt: the fair value is based on quoted market prices where available or by discounting remaining cash flows at current market rates.

We show the carrying amounts and fair values of financial instruments included in our Consolidated Balance Sheets in the following table, and we describe some of the items separately later in this section.

At December 31,	2001		2000	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In millions)			
Investments and other assets for which it is:				
Practicable to estimate fair value	**$1,144.9**	**$1,144.9**	$ 349.8	$ 349.8
Not practicable to estimate fair value	**25.8**	**N/A**	32.7	N/A
Fixed-rate long-term debt	**2,945.3**	**3,069.6**	2,734.1	2,819.9
Variable-rate long-term debt	**1,179.1**	**1,179.1**	1,331.8	1,331.8

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. 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 $25.8 million at December 31, 2001 and $32.7 million at December 31, 2000, representing ownership interests up to 11%. The total assets of all of these partnerships totaled $5.4 billion at December 31, 2000 (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 $47.9 million at December 31, 2001 and $341.0 million at December 31, 2000.

Our merchant energy business guaranteed outstanding debt totaling $414.8 million at December 31, 2001 and $33.6 million at December 31, 2000.

Our other nonregulated businesses guaranteed outstanding debt totaling $15.9 million at December 31, 2001 and $16.5 million at December 31, 2000.

BGE guaranteed outstanding debt of $263.3 million at December 31, 2001 and 2000.

We do not anticipate that we will need to fund these guarantees.

Note 13. 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 nonqualified stock options. Options have been 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. 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:

	2001		2000	
	Shares	Weighted-Average Exercise Price	Shares	Weighted-Average Exercise Price
	(In thousands, except per share amounts)			
Outstanding, beginning of year	**2,420**	**$34.65**	–	$ –
Granted	**1,015**	**25.08**	2,462	34.64
Exercised	**(512)**	**(34.25)**	–	–
Cancelled/ Expired	**(277)**	**(37.74)**	(42)	(34.25)
Outstanding, end of year	**2,646**	**$30.73**	2,420	$34.65
Exercisable, end of year	**235**	**$34.25**	–	–
Weighted-average fair value per share of options granted		**$ 9.27**		$ 5.60

The following table summarizes information about stock options outstanding at December 31, 2001 (shares in thousands):

Plan Year	Exercise Prices	Number Outstanding	Weighted-Average Remaining Contractual Life	Number Exercisable
2001	$25.08	1,015	9.9	–
2000	$34.25	1,631	8.4	235

Performance-Based Restricted Stock Awards

In addition, we issue common stock based on meeting certain performance and service goals over a three to five year period. This stock vests to participants at various times ranging from three to five years or less. In accordance with APB No. 25, we recognize compensation expense for our restricted stock awards using the variable accounting method. In 2001, due to non-attainment of performance criteria, we recorded a credit to compensation expense of $10.1 million. We recorded compensation expense of $16.3 million for 2000 and $10.5 million for 1999. Summarized share information for our restricted stock awards is as follows:

	2001	2000	1999
	(In thousands, except per share amounts)		
Outstanding, beginning of year	**377**	323	350
Granted	**87**	353	358
Released to participants	**–**	(277)	(362)
Cancelled	**(29)**	(22)	(23)
Available for grant, end of year	**435**	377	323
Weighted-average fair value restricted stock granted	**$35.24**	$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:

	2001	2000
Risk-free interest rate	**4.79%**	6.37%
Expected life (in years)	**5.0**	10.0
Expected market price volatility factors	**41.3%**	21.0%
Expected dividend yields	**1.8%**	5.7%

Had compensation cost for these plans been recognized under the fair value method, net income and basic and diluted earnings per share amounts would have been as follows:

	2001
	(In millions, except per share amounts)
Pro-forma net income	$87.2
Pro-forma earnings per share:	
Basic	$ .54
Diluted	$ .54

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 for the year ended December 31, 2000.

Note 14. Acquisition of Nine Mile Point

On November 7, 2001, we completed our purchase of Nine Mile Point located in Scriba, New York. Nine Mile Point consists of two boiling-water reactors. Unit 1 is a 609-megawatt reactor that entered service in 1969. Unit 2 is a 1,148-megawatt reactor that began operation in 1988.

Nine Mile Point Nuclear Station, LLC, a subsidiary of Constellation Nuclear, purchased 100 percent of Nine Mile Point Unit 1 and 82 percent of Unit 2. Approximately one-half of the purchase price, or $380 million, in addition to settlement costs of $2.7 million, was paid at closing. The remainder is being financed through the sellers in a note to be repaid over five years with an interest rate of 11.0%. This note may be prepaid at any time without penalty. The sellers also transferred to us approximately $442 million in decommissioning funds. As a result of this purchase, we own 1,550 megawatts of Nine Mile Point's 1,757 megawatts of total generating capacity.

Niagara Mohawk Power Corporation was the sole owner of Nine Mile Point Unit 1. The co-owners of Unit 2 who sold their interests are: Niagara Mohawk (41 percent), New York State Electric and Gas (18 percent), Rochester Gas & Electric Corporation (14 percent), and Central Hudson Gas & Electric Corporation (9 percent). The Long Island Power Authority will continue to own 18 percent of Unit 2.

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

Nine Mile Point Net Assets Acquired

At November 7, 2001

	(In millions)
Current Assets	$135.4
Nuclear Decommissioning Trust Fund	441.7
Net Property, Plant and Equipment	292.6
Intangible Assets (details below)	38.7
Total Assets Acquired	908.4
Current Liabilities	16.9
Deferred Credits and Other Liabilities	120.7
Net Assets Acquired	770.8
Note to Sellers	388.1
Total cash paid	$382.7

The intangible assets acquired consist of the following:

Description	Amount	Weighted-Average Useful Life
	(In millions)	*(In years)*
Operating procedures and manuals	$23.4	10
Permits and licenses	12.9	27
Software	2.4	5
Total intangible assets	$38.7	

In 2002, Niagara Mohawk, or its successor, will provide funds equal to the net pension obligation of Nine Mile Point employees following a more precise estimate of this obligation. Refer to Note 7 on page 72 for additional information.

Note 15. 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 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.

2001 Quarterly Data

	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	**$1,147.1**	**$235.0**	**$111.8**	**$0.74**
June 30	**843.2**	**171.0**	**75.6**	**0.46**
September 30	**1,036.1**	**317.5**	**163.6**	**1.00**
December 31	**901.9**	**(365.7)**	**(260.1)**	**(1.59)**
Year Ended				
December 31	**$3,928.3**	**$357.8**	**$ 90.9**	**$0.57**

Our first quarter results include a $8.5 million after-tax gain for the cumulative effect of adopting SFAS No. 133.

Our fourth quarter results include workforce reduction costs, contract termination related costs, and impairment losses and other costs totaling $334.8 million after-tax. For details, refer to Note 2 on page 64.

2000 Quarterly Data

	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	$ 994.0	$184.6	$ 72.1	$0.48
June 30	866.6	132.1	39.6	0.26
September 30	968.6	313.4	147.5	0.98
December 31	1,023.3	212.5	86.1	0.57
Year Ended				
December 31	$3,852.5	$842.6	$345.3	$2.30

Our first quarter results include a $2.5 million after-tax expense for BGE employees that elected to participate in a targeted VSERP as discussed in more detail in Note 2 on page 66.

Our second quarter results include:

- a $15.0 million after-tax deregulation transition cost to Goldman Sachs incurred by our power marketing operation to provide BGE's standard offer service requirements, and
- a $1.7 million after-tax expense for the VSERP as discussed in more detail in Note 2 on page 66.

The sum of the quarterly earnings per share amounts may not equal the total for the year due to the effects of rounding and dilution as a result of issuing common shares during the year.

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

Christian H. Poindexter
Chairman,
Constellation Energy Group
Board of Directors
Age 63
Director since 1988*

Mayo A. Shattuck III
President and
Chief Executive Officer,
Constellation Energy Group
Age 47
Director since 1994**

Douglas L. Becker
Chairman and Chief
Executive Officer, Sylvan
Learning Systems, Inc.
Age 36
Director since 1998*

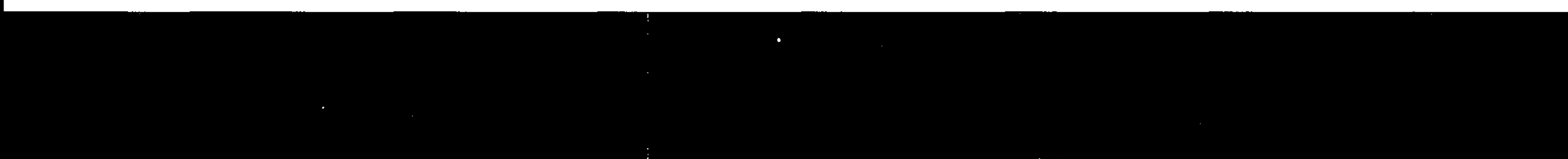
James T. Brady
Managing Director,
Mid-Atlantic of Ballantrae
International, Ltd.
Age 61
Director since 1998**

Frank P. Bramble, Sr.
Chief Executive USA,
Allied Irish Banks, p.l.c.
and Chairman,
Allfirst Financial, Inc.
Age 53
Director since 2002

Beverly B. Byron
Former Congresswoman,
U.S. House of Representatives
Age 69
Director since 1993*

Edward A. Crooke
Retired Vice Chairman,
Constellation Energy Group
Age 63
Director since 1988*

James R. Curtiss, Esq.
Partner, Winston & Strawn
Age 48
Director since 1994*



Roger W. Gale
Senior Advisor, PA
Consulting
Age 55
Director since 1995**

Dr. Freeman A.
Hrabowski III
President, University of
Maryland Baltimore County
Age 51
Director since 1994*

Edward J. Kelly III
President and Chief Executive
Officer, Mercantile Bankshares
Corporation
Age 48
Director since 2001

Nancy Lampton
Chairman and Chief
Executive Officer, American
Life and Accident Insurance
Company of Kentucky
Age 59
Director since 1994*

Charles R. Larson
Admiral, United States Navy
(Retired)
Age 65
Director since 1998*

Robert J. Lawless
Chairman, President and
Chief Executive Officer,
McCormick & Company, Inc.
Age 55
Director since 2001

Michael D. Sullivan
Chairman, Life Source, Inc.
Age 62
Director since 1992*

* *Formerly a BGE Director, was elected to the Constellation Energy Group Board of Directors in April 1999 at the formation of the holding company.*

** *Formerly a Director of a subsidiary, was elected to the Constellation Energy Group Board of Directors in May 1999.*

Seated, from left: Dr. Hrabowski, Ms. Lampton, Mr. Poindexter, Mr. Shattuck, Mr. Gale, Mr. Becker
Standing, from left: Mr. Brady, Mr. Sullivan, Adm. Larson, Mr. Bramble, Mr. Curtiss, Mr. Crooke, Mr. Kelly, Ms. Byron, Mr. Lawless

Committees of the Board

Executive Committee

Christian H. Poindexter, Chairperson
Mayo A. Shattuck III
Frank P. Bramble, Sr.
Edward A. Crooke
Edward J. Kelly III
Robert J. Lawless

Audit Committee

James T. Brady, Chairperson
Freeman A. Hrabowski III
Nancy Lampton

Committee on Management

Michael D. Sullivan, Chairperson
Douglas L. Becker
Frank P. Bramble, Sr.
Edward J. Kelly III
Robert J. Lawless

Committee on Nuclear Power

James R. Curtiss, Chairperson
Beverly B. Byron
Adm. Charles R. Larson (Ret.)
Roger W. Gale

Constellation Energy's executive team is diverse in experience, background, and point of view. Those who are steeped in the knowledge and experience of Constellation work side-by-side with those who have been recruited for their expertise gained around the world. Together they combine the right mix of energy industry tradition and competitive business savvy necessary for today's changing energy landscape.

Christian H. Poindexter
Chairman of the Board
63, joined BGE* in 1967; served as Project Engineer during Calvert Cliffs Nuclear Power Plant's construction; was Chief Nuclear Engineer 1974-76; became Treasurer-Assistant Secretary in 1978 and Vice President–Engineering and Construction in 1980; named President and CEO of Constellation Holdings, Inc., in 1985; elected BGE Vice Chairman in 1989 and Chairman, President, CEO in 1993.

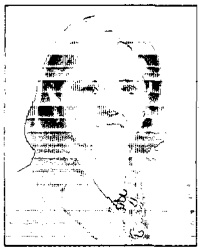
Mayo A. Shattuck III
President and Chief Executive Officer
47, joined Constellation Energy in 2001. Prior to this he was Chairman, DB Alex. Brown, and CEO–Private Client and Asset Management Group, Americas, and Global Head-Private Banking Division. In 1991, he was elected President and COO of Alex. Brown, Inc., which merged with Bankers Trust in 1997; served as Bankers Trust Vice Chairman until it merged with Deutsche Bank in 1999; served as Co-Head of Global Investment Banking for Deutsche Bank, and Co-Chairman and Co-CEO of DB Alex. Brown and Deutsche Bank Securities until 2001.

Thomas V. Brooks
President, Constellation Power Source
39, joined Constellation Energy in 2001 as Vice President, Business Development & Strategy. Prior to this, he was Vice President, Goldman Sachs working with Constellation to develop its power marketing business; previously served as director, Enron Capital & Trade Resources, joining them when they bought AERX, Inc., a company he helped found that specialized in emissions credit trading.

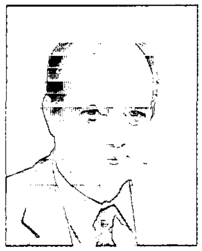
Frank O. Heintz
President and Chief Executive Officer, BGE
58, joined BGE* in 1996 as Vice President, assuming leadership of its Gas Division in 1997; elected Executive Vice President, BGE Utility Operations Group in 1998. Prior to this he served 13 years as Chairman, Maryland Public Service Commission.

Michael J. Wallace
President, Constellation Generation Group
54, joined Constellation Energy in 2002. Prior to this he was co-founder and Managing Director, Barrington Energy Partners, LLC, an energy industry strategic consulting firm. Previously he served as Senior Vice President and Chief Nuclear Officer, Unicom/ComEd of Illinois.

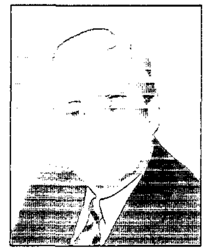
Thomas F. Brady
Vice President, Corporate Strategy & Development
52, also Chairman of BGE HOME, Constellation Energy Source, and our other nonregulated businesses. Joined BGE* in 1969; became Assistant Treasurer–Assistant Secretary in 1983; elected Vice President, Accounting & Economics in 1988; Vice President, Customer Service & Accounting in 1991; Vice President Customer Service & Distribution in 1993; Vice President Retail Services 1998; and assumed current position in 1999.



E. Follin Smith
Senior Vice President and Chief Financial Officer
42, joined Constellation Energy in 2001. Prior to this she was Senior Vice President and CFO of Armstrong Holdings, Inc. Previously, she spent 15 years with General Motors (GM), starting in the New York Treasurer's Office; other positions included Treasurer–GM of Canada Limited; Vice President of Finance for GMAC; Assistant Treasurer for GM; and CFO for GM's Delphi Chassis Systems division.

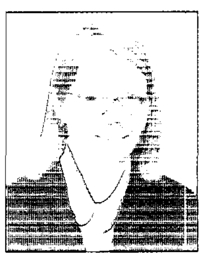


Paul J. Allen
Vice President, Corporate Affairs
50, joined Constellation Energy in 2001. Prior to this he was Senior Vice President and Group Head–Ogilvy Public Relations, managing its energy and environment practice. Previously he served as senior staff member at Natural Resources Defense Council; Press Secretary for U.S. Senator Christopher Dodd; and National Public Radio's Editor of "Morning Edition" and then Foreign News Editor.

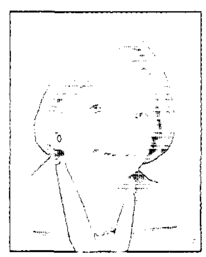


David A. Brune
Vice President, General Counsel and Secretary
61, joined BGE* in 1976; named General Counsel in 1984; elected CFO, Vice President-Finance & Accounting and Corporate Secretary in 1997 and took over his current position in 2001.

John R. Collins
Vice President and Chief Risk Officer
44, joined BGE* in 1988; named Assistant Treasurer and Director of Financial Management in 1995; joined Constellation Power Source at its formation in1997, serving as its senior financial officer; became Managing Director–Finance and Treasurer, Constellation Power Source Holdings in 2000.



Diane L. Featherstone
Vice President, Management Consulting & Auditing
48, joined BGE* in 1976; in 1992 was named Manager, Staff Services; elected President and CEO, Constellation Energy Source in 1997; was named to her current position in 2001.



Elaine W. Johnston
Vice President, Human Resources
60, joined BGE* in 1987; named Manager, Constellation Enterprises** HR Services in 1998 and Managing Director– Human Resources & Administration, Constellation Power Source Holdings in January 2001.

* *On April 30, 1999, Constellation Energy Group, Inc. became the holding company for Baltimore Gas and Electric Company (BGE) and its subsidiaries.*

** *Constellation Enterprises was previously owned by BGE and was the holding company for BGE's nonregulated businesses.*

	2001	2000	1999	1998	1997
Common Stock Data					
Quarterly Earnings Per Share					
First Quarter	$0.74	$0.48	$0.55	$0.50	$0.43
Second Quarter	0.46	0.26	0.45	0.39	0.05
Third Quarter	1.00	0.98	0.91	1.08	1.11
Fourth Quarter	(1.59)	0.57	(0.18)	0.09	0.12
Total	$0.57	$2.30	$1.74	$2.06	$1.72
Earnings Per Share Before Special Costs Included in Operations and Nonrecurring Items	$2.60	$2.43	$2.48	$2.20	$2.28
Dividends					
Dividends Declared Per Share	$0.48	$1.68	$1.68	$1.67	$1.63
Dividends Paid Per Share	0.78	1.68	1.68	1.66	1.62
Dividend Payout Ratio					
Reported	84.2%	73.0%	96.6%	81.1%	94.8%
Excluding special costs and nonrecurring charges	18.5%	69.1%	67.7%	75.9%	71.5%
Market Prices					
High	$50.14	$52.06	$31.50	$35.25	$34.31
Low	20.90	27.06	24.69	29.25	24.75
Close	26.55	45.06	29.00	30.88	34.13
Capital Structure					
Long-Term Debt	45.1%	52.9%	48.6%	53.5%	48.3%
Short-Term Borrowings	10.7	3.2	5.4	–	4.7
BGE Preference Stock	2.1	2.5	2.7	2.8	4.4
Common Shareholders' Equity	42.1	41.4	43.3	43.7	42.6

The sum of the quarterly earnings per share amounts may not equal the total for the year due to the effects of rounding and changes in the average number of shares outstanding throughout the year.

The quarterly earnings per share amounts include certain one-time adjustments as shown in Note 15 on page 87 to the Consolidated Financial Statements.

Common Stock Dividends and Price Ranges

2001	Dividend Declared	Price High	Price Low
First Quarter	$0.12	$44.65	$34.69
Second Quarter	0.12	50.14	40.10
Third Quarter	0.12	43.80	22.85
Fourth Quarter	0.12	28.21	20.90
Total	$0.48		

2000	Dividend Declared	Price High	Price Low
First Quarter	$0.42	$33.81	$27.06
Second Quarter	0.42	35.69	31.25
Third Quarter	0.42	52.06	32.06
Fourth Quarter	0.42	50.50	37.88
Total	$1.68		

Dividend Policy

The common stock is entitled to dividends when and as declared by the Board of Directors. There are no limitations in any indenture or other agreements on payment of dividends.

Dividends have been paid on the common stock continuously since 1910. Future dividends depend upon future earnings, the financial condition of the company, and other factors.

Dividend Increase

On January 30, 2002, the Board of Directors announced it will increase the dividend to 96 cents per share (24 cents quarterly). The company had been paying an annual rate of 48 cents per share (12 cents quarterly), which was established April 3, 2001.

Common Stock Dividend Dates

Record dates are normally on the 10th of March, June, September, and December. Quarterly dividends are customarily mailed to each shareholder on or about the 1st of April, July, October, and January.

Stock Trading

Constellation Energy Group's common stock, which is traded under the ticker symbol CEG, is listed on the New York, Chicago, and Pacific stock exchanges, and has unlisted trading privileges on the Boston, Cincinnati, and Philadelphia exchanges. As of December 31, 2001, there were 54,285 common shareholders of record.

Annual Meeting

The annual meeting of shareholders will be held at 10 a.m. on Friday, May 24, 2002, in the 2nd Floor Conference Room of the Gas and Electric Building, located at 39 W. Lexington Street, Baltimore, Maryland 21201.

Form 10-K

Upon written request, the company will furnish, without charge, a copy of its and BGE's Annual Report on Form 10-K, including financial statements. Requests should be addressed to Constellation Energy Group, Inc., Shareholder Services, P.O. Box 1642, Baltimore, MD 21203-1642.

Auditors

PricewaterhouseCoopers LLP

Executive Offices

250 W. Pratt Street
Baltimore, Maryland 21201
Mail: P.O. Box 1475, Baltimore, Maryland 21203-1475

Shareholder Investment Plan

Constellation Energy Group's Shareholder Investment Plan provides common shareholders an easy and economical way to acquire additional shares of common stock. The plan allows shareholders to reinvest all or part of their common stock dividends; purchase additional shares of common stock; deposit the common stock they hold into the plan; and request a transfer or sale of shares held in their accounts.

Stock Transfer Agents and Registrars

Transfer Agent and Registrar:
Constellation Energy Group, Inc.
Baltimore, Maryland

Co-Transfer Agent and Registrar:
Continental Stock Transfer and Trust Company
8th Floor
17 Battery Place South
New York, NY 10004

Shareholder Assistance and Inquiries

If you need assistance with lost or stolen stock certificates or dividend checks, name changes, address changes, stock transfers, the Shareholder Investment Plan, or other matters, you may visit our Web site at www.constellationenergy.com or contact our shareholder service representatives as follows:

By telephone (Monday–Friday, 8 a.m. – 4:45 p.m. EST):

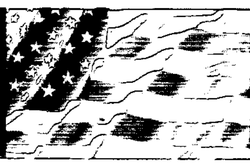
Baltimore Metropolitan Area	410-783-5920
Within Maryland	1-800-492-2861
Outside Maryland	1-800-258-0499

By U.S. mail:
Constellation Energy Group, Inc.
Shareholder Services
P.O. Box 1642
Baltimore, MD 21203-1642

In person or by overnight delivery:
Constellation Energy Group, Inc.
Shareholder Services, Room 800
39 W. Lexington Street
Baltimore, MD 21201

Constellation Energy Group

250 W. Pratt Street
Baltimore, Maryland 21201
www.constellationenergy.com



United We Stand