**Charles H. Cruse**
Vice President
Nuclear Energy

1650 Calvert Cliffs Parkway
Lusby, Maryland 20657
410 495-4455

**Constellation**
Nuclear

Calvert Cliffs
Nuclear Power Plant

*A Member of the*
*Constellation Energy Group*

August 15, 2000

U. S. Nuclear Regulatory Commission
Washington, DC 20555

**ATTENTION:** Director, Nuclear Reactor Regulation

**SUBJECT:** Calvert Cliffs Nuclear Power Plant
Unit Nos. 1 & 2; Docket Nos. 50-317 & 50-318
Guarantee of Retrospective Premium

In accordance with the requirements of 10 CFR 140.21, we are attaching the guarantee of payment of deferred premiums for out Calvert Cliffs Nuclear Power Plant reactors.

| | |
|---|---|
| Exhibit I | A copy of the 1999 Annual Report to Shareholders of Baltimore Gas and Electric Company containing certified financial statements |
| Exhibit II | A copy of quarterly financial statements as of June 30, 2000 |
| Exhibit III | A copy of Projected Cash Flow for the twelve months ended July 31, 2001 |
| Exhibit IV | Narrative statement on curtailment/deferment of capital expenditures (if any) to ensure that retrospective premiums up to $10 million per reactor year for each nuclear incident would be available for payment. |

Should you have questions regarding this matter, we will be pleased to discuss them with you.

Very truly yours,

Charles H. Cruse

CHC/JKK/dlm
Attachments: As stated

cc: Document Control Desk, NRC

**(Without Attachments)**
R. S. Fleishman, Esquire
J. E. Silberg, Esquire
Director, Project Directorate I-1, NRC
A. W. Dromerick, NRC
H. J. Miller, NRC
Resident Inspector, NRC
R. I. McLean, DNR
J. H. Walter, PSC

M004

## EXHIBIT I

# 1999 ANNUAL REPORT TO SHAREHOLDERS

**Baltimore Gas and Electric Company**
**Calvert Cliffs Nuclear Power Plant**
**August 15, 2000**

what we call **results** are **beginnings**

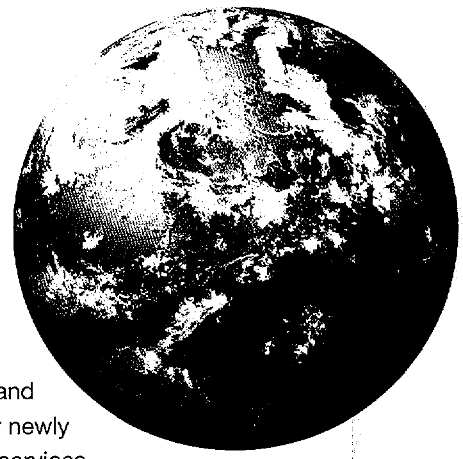
1999 Annual Report to Shareholders

C1

# Constellation Energy Group at a Glance

Constellation Energy Group (NYSE:CEG) is a holding company whose subsidiaries include a group of energy businesses focused mostly on power marketing and merchant generation in North America and the Baltimore Gas and Electric Company (BGE). In 1999, combined revenues totaled $3.8 billion.

## Here are the Constellation Stars:



### Constellation Power Source

Our integrated domestic merchant energy company provides wholesale customers with solutions to their energy needs. Combining expertise in marketing and risk management with the development, ownership and operation of power plants, Constellation Power Source actively markets power and risk management services throughout North America.

### Constellation Nuclear Group

Our nuclear generation and consulting business brings together our experience and expertise in the nuclear industry. Under the Constellation Nuclear umbrella is our newly formed Constellation Nuclear Services, Inc., which provides nuclear consulting services specializing in nuclear power plant license renewal and life-cycle management. In July 2000, upon receipt of all regulatory approvals, the Calvert Cliffs Nuclear Power Plant will be moved under that umbrella as well.

### Baltimore Gas and Electric Company

Our regulated, electric and gas utility serves more than 1.1 million electric customers and more than 584,000 gas customers in Central Maryland. Up until deregulation of the generation part of the business on July 1, 2000, BGE will provide services to these customers as a fully integrated utility with operations as listed below:

**Generation:** Owns and operates 10 Maryland-based power stations, including the Calvert Cliffs Nuclear Power Plant; shares ownership of three power plants in Pennsylvania; total generating capacity exceeds 6,200 megawatts.

**Electricity Delivery:** Provides electricity throughout a 2,300-square-mile service territory through its transmission and distribution system and is a member of the PJM (Pennsylvania-New Jersey-Maryland) Interconnection, a regional power pool of wholesale market participants and other utility companies.

**Natural Gas Delivery:** Delivers natural gas through nearly 5,600 miles of gas main in a 600-square-mile service territory.

On July 1, 2000, BGE's generating assets will be transferred to our nonregulated subsidiaries, pending full regulatory approval. BGE will then continue to operate as our electric and natural gas delivery business, serving its Central Maryland customers.

### BGE Home Products & Services

Our local home products, commercial buildings, and gas retail marketing business offers a wide range of home energy products and services and commercial building systems in Maryland, Virginia, and Washington, D.C. After July 2000, BGE HOME will begin marketing electricity, as well as gas, to residential and small commercial customers in Maryland.

### Constellation Energy Source

Our energy products and services business provides customized energy solutions exclusively to commercial and industrial customers, primarily in the mid-Atlantic region.

**Committed to Equal Opportunity:** As an Equal Opportunity Employer, Constellation Energy Group does not discriminate on the basis of age, color, disability, marital status, national origin, race, religion, sex, sexual orientation, or veteran status.

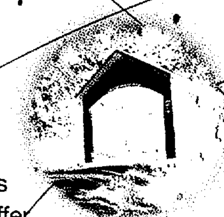
| | 1999 | 1998 | % Change |
|---|---|---|---|
| | *(In millions, except per share amounts)* | | |
| **Common Stock Data** | | | |
| **Earnings per share** | | | |
| Earnings per share before nonrecurring charges included in operations | | | |
| Utility business | $ **2.03** | $ 1.93 | 5.2 % |
| Diversified businesses | **.45** | .27 | 66.7 |
| Total earnings per share before nonrecurring charges included in operations | **2.48** | 2.20 | 12.7 |
| Nonrecurring charges included in operations | | | |
| *Hurricane Floyd | **(.03)** | – | |
| *Write-downs of power projects | **(.12)** | – | |
| *Write-down of financial investment | **(.11)** | – | |
| *Write-downs of real estate and senior-living investments | **(.04)** | (.10) | |
| *Write-off of energy services investment | – | (.04) | |
| Total earnings per share before extraordinary item | **2.18** | 2.06 | 5.8 |
| Extraordinary loss | **(.44)** | – | |
| Total earnings per share | $ **1.74** | $ 2.06 | (15.5) |
| **Dividends declared per share** | $ **1.68** | $ 1.67 | 0.6 |
| **Average shares outstanding** | **149.6** | 148.5 | 0.7 |
| **Return on average common equity** | | | |
| Reported | **8.6%** | 10.5% | (18.1) |
| Excluding nonrecurring charges to earnings | **12.3%** | 11.2% | 9.8 |
| **Book value per share—year-end** | **$ 20.01** | $ 19.98 | 0.2 |
| **Market price per share—year-end** | **$29.000** | $30.875 | (6.1) |
| **Financial Data** | | | |
| **Revenues** | | | |
| Electric | **$ 2,259** | $ 2,219 | 1.8 |
| Gas | **476** | 449 | 6.0 |
| Diversified businesses | **1,051** | 690 | 52.3 |
| Total revenues | **$ 3,786** | $ 3,358 | 12.7 |
| **Income before extraordinary item** | $ **326** | $ 306 | 6.5 |
| **Extraordinary loss, net of income taxes** | **(66)** | – | |
| **Net income** | $ **260** | $ 306 | (15.0) |
| **Total assets** | **$ 9,684** | $ 9,275 | 4.4 |
| **Utility construction expenditures (excluding AFC)** | $ **376** | $ 329 | 14.3 |
| **Investment in utility business** | **$ 2,349** | $ 2,467 | (4.8) |
| **Investment in diversified businesses** | $ **643** | $ 515 | 24.9 |
| **Utility System Data** | | | |
| Electric system sales—megawatt-hours | **29.3** | 28.8 | 1.7 |
| Gas system sales—dekatherms | **105.2** | 100.1 | 5.1 |

**Nonrecurring charges to earnings discussed in Note 2 to the Consolidated Financial Statements on page 55.*

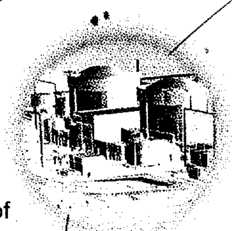
*Certain prior-year amounts have been reclassified to conform with the current year's presentation.*

# It's been a **stellar** year

**December 31, 1999**
Y2K comes and goes without a glitch on our systems.

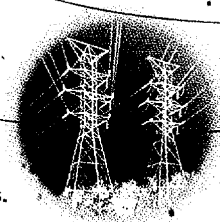


**January 5, 1999**
Constellation Power Source wins contracts to supply standard offer service in New England.



**July 28, 1999**
Calvert Cliffs Nuclear Power Plant receives the highest rating given by the Institute of Nuclear Power Operations.

**November 10, 1999**
PSC approves BGE's electric deregulation settlement plan.



**July 6, 1999**
BGE sets new peak load record of 6,383 megawatts.

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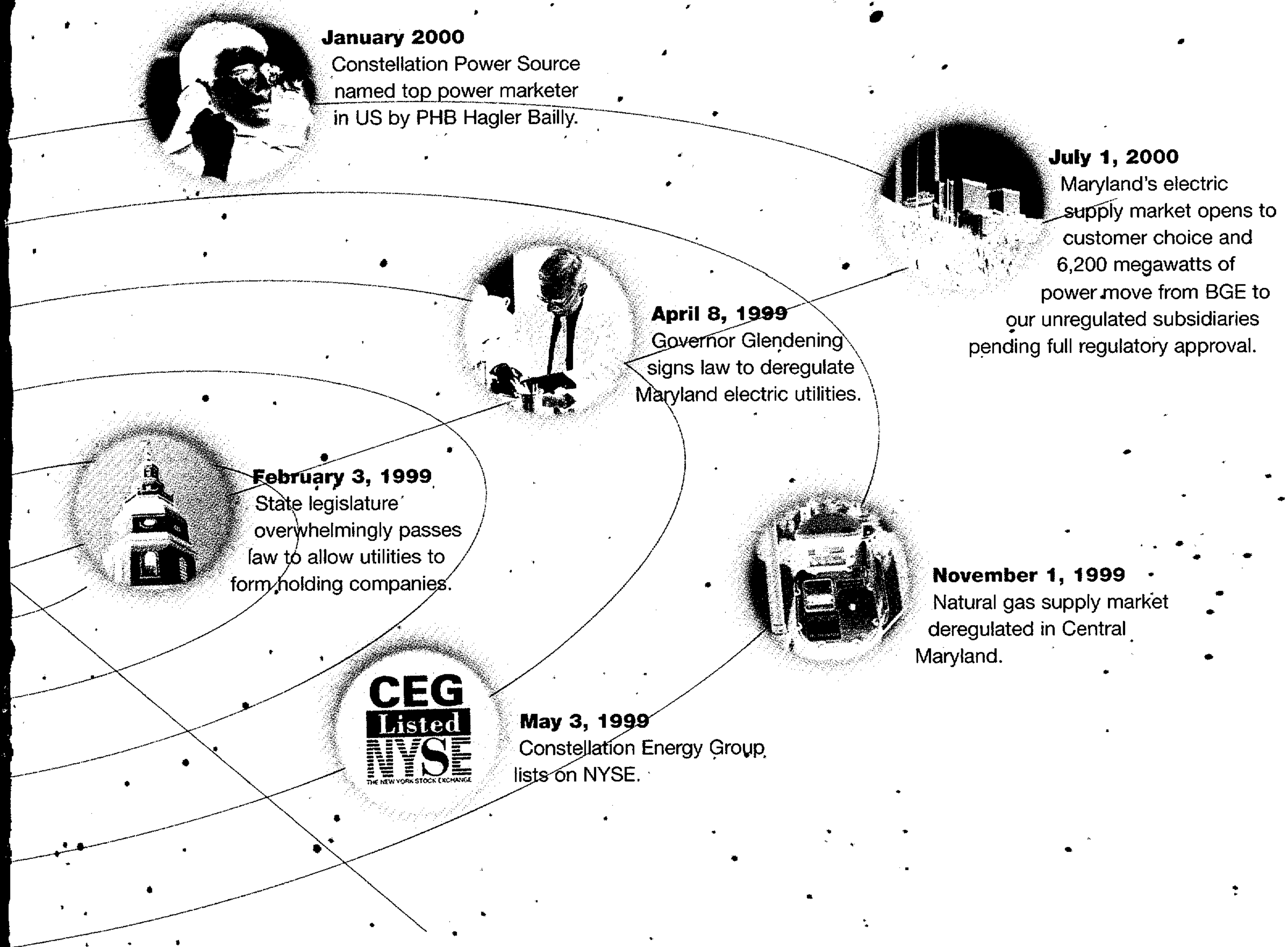



# A bright star on the energy horizon

Our **results** at the close of 1999 marked an exciting new **beginning** for our company. With the creation of the Constellation Energy Group, we took bold steps toward shaping our business to create the organization that will lead us to success in the future.

From our legacy as a respected local utility will emerge a national energy company that will aggressively compete in the growing wholesale power market. As part of our strategy, we will continue our strong regional presence as a leader in utility and energy-related services.

## *In creating the Constellation Energy Group holding company last Now we are putting in place the major pieces of the competitive*

**Dear Investor,**

Nineteen ninety-nine was arguably the most pivotal year in our company's history. The events of last year have forever changed the energy landscape in Maryland and have set in motion a fundamental transformation of our corporation.

In our 1998 annual report, I said we were determined to win in the new energy market and outlined the primary strategies we would pursue to ensure success. They included:

- *Be a leader in wholesale power marketing and generation in North America.*
- *Provide premier utility services to Maryland while managing the transition to competitive energy markets.*

In this report, you will read about the overall progress we have made in executing those strategies. The results of our efforts point to the fact that your company is both determined and winning in the competitive energy marketplace.

Despite our progress, we are not satisfied with the recent performance of our stock. The investment return on Constellation Energy Group's stock, and the utility industry in general, has lagged behind the overall market. Still, we were one of the stronger performers among utilities in 1999, with total shareholder return outpacing the Standard & Poor's Electric Utility Index by more than 19%. In early February 2000, our market price reached a 52-week high.

The relative strength of our stock provides tangible evidence that investors are starting to reward some companies, like Constellation Energy Group, that are taking a focused approach to grow in a deregulated environment. We are working hard on all fronts to ensure we continue to build shareholder value as we navigate through deregulation. Here's a look at the progress made last year and how we plan to continue delivering value in 2000 and beyond.

### A New Company Is Born

The action began in February 1999, when the Maryland General Assembly passed legislation allowing BGE to form a holding company. Following your approval at the annual shareholders' meeting, the Constellation Energy Group started trading on the New York Stock Exchange on May 3.

Throughout the legislative session, we worked closely with key stakeholders and state lawmakers to develop the legal framework that would shape Maryland's electric market. In April, Governor Parris Glendening signed comprehensive legislation that is the foundation for opening Maryland's electric generation business to competition.

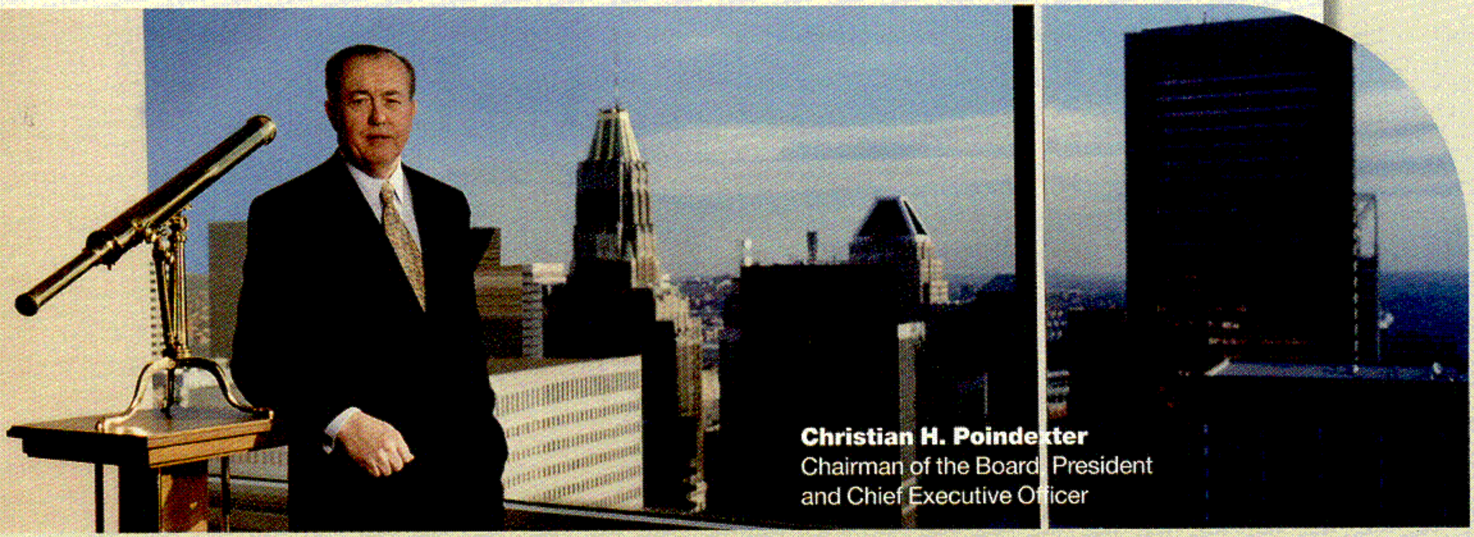
With legislation in place, we moved quickly to negotiate an equitable settlement agreement with all but one of the key parties to BGE's electric deregulation transition plan. On November 10, 1999, the Maryland Public Service Commission (PSC) approved that settlement, allowing all BGE electric customers to choose their electric suppliers beginning July 1, 2000. *(For highlights of the settlement order, see page 6.)*

This historic decision resolves many critical details needed to ensure a smooth transition from a regulated to a competitive electric market. Most important, it enables Constellation Energy Group to move forward on sound financial footing, while providing BGE's customers with important safeguards.

Significantly for BGE residential customers, the settlement secures a 6.5% reduction in electric base rates for six years and financial protections for low-income customers. For Constellation Energy Group, it allows us to recover a significant portion of our transition costs, as well as move our utility generation assets to our nonregulated subsidiaries. While the settlement decision has been appealed in court, we believe that electric deregulation in the state and our company's plans can move forward.

*year, we launched a new growth-oriented energy company.*

*business strategies we believe will make us winners.*



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

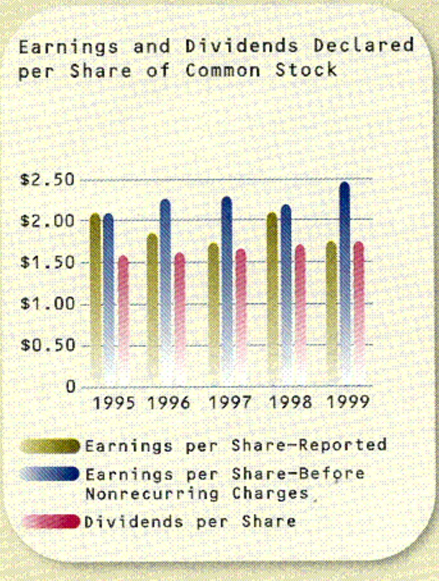
## Financial Results Reflect Growing Pains of Change

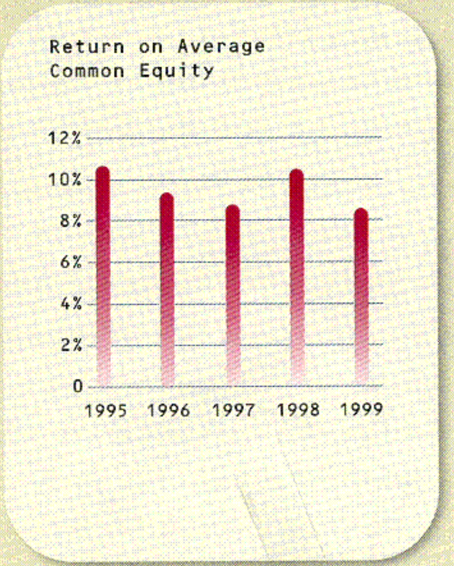
The move to a deregulated electric generation supply market comes with some growing pains. A part of our settlement required that we recognize certain expenses related to the deregulation of our utility generating assets before July 1, 2000.

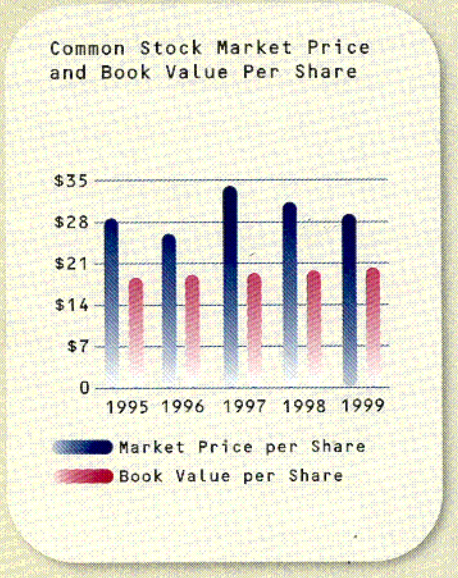
Consequently, after accounting for one-time charges and the extraordinary loss related to deregulation, our reported earnings were $1.74 a share compared with $2.06 in 1998. Excluding these charges, our earnings per share in 1999 were $2.48 per share, a 12.7% increase over operating earnings of $2.20 in 1998.

Despite this initial earnings reduction, we feel the settlement order is a good agreement that positions the company to successfully pursue opportunities in a competitive energy market.

Utility earnings from operations, excluding the nonrecurring charges, increased about 5% in 1999 versus 1998. Diversified earnings from operations grew 67% over 1998, thanks to substantial contributions from Constellation Power Source, our power marketing business.



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### Operations Produce Results

Our Constellation Power Source subsidiary emerged from 1999 as a leader in the power marketing business. With earnings four times higher than 1998, it continued to profitably expand operations throughout North America.

In less than three years, Constellation Power Source has become one of a handful of customer-focused merchant energy companies able to deliver effective energy solutions in a competitive wholesale marketplace. In fact, PHB Hagler Bailly, a leading management and economic consulting company in the energy industry, named Constellation Power Source the top U.S. power marketer in its *Energy Industry Outlook 2000*.

In 1998, we were a founding investor, along with a Goldman, Sachs & Co. affiliate, of Orion Power Holdings, Inc. Since then, Orion has steadily increased its generation portfolio. When the acquisition of Duquesne Light Company's generation assets announced last year is completed, Orion's portfolio will total more than 5,200 megawatts of power.

Once again, BGE's power plants had an excellent year, with fossil plants generating an all-time record 19.4 million megawatt-hours. This marks the tenth consecutive year they've set a record for total output. Calvert Cliffs Nuclear Power Plant generated 13.3 million megawatts, nearly matching its all-time production level set in 1998.

We are expecting a decision from the Nuclear Regulatory Commission sometime this year on our application to extend the operating licenses for the Calvert Cliffs Nuclear Power Plant. Commission approval will allow these two units to operate for up to 20 years beyond the current licenses, extending operation dates to 2034 and 2036.

BGE's distribution and customer service employees faced one of their most challenging years ever. The devastating ice storm in January was followed by Hurricane Floyd in September, which caused the worst damage to our system in our history. Our employees responded heroically during the restoration efforts of both storms, and we learned a lot from our efforts. Following an intense critique of that experience, we are implementing ways to improve service restoration and communications with customers during major outages.

# Advancing Our

With deregulation legislation in place and our PSC settlement approved, we took major steps toward advancing our competitive business strategy. As deregulation unfolds and we move forward, we will experience vast changes in the way we do business.

In the past, the majority of our earnings have come from BGE. That equation is changing. Under deregulation, the delivery of electricity and gas will remain regulated, while both electric generation and gas supply will be competitive.

### We'll Be Ready for Customer Choice

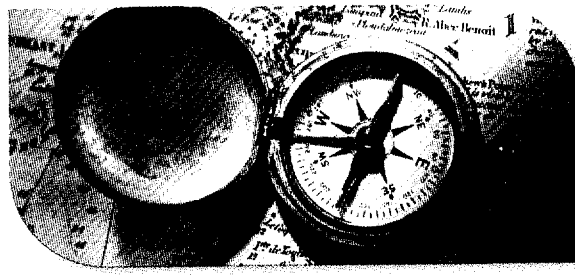
Operationally, our first priority for the year 2000 is to have all systems ready to meet the July 1 deadline for opening the electric market in Maryland. The transition will require major internal changes from an organizational standpoint.

To accomplish this, we're reorganizing our operations into three main business units—the regulated BGE utility, our Constellation Power Source merchant energy company, and our nuclear subsidiary. Our goal is to have these businesses operating smoothly to effect a seamless transition to customer choice.

On July 1, 2000, pending full regulatory approval, BGE's generating assets will be transferred to our nonregulated subsidiaries. Our fossil energy plants will become part of Constellation Power Source, while the Calvert Cliffs Nuclear Plant will move under Constellation Nuclear Group. BGE will, as a result, become a "pipes and wires" utility, continuing its historic role of delivering natural gas and electricity through its networks to homes and businesses throughout Central Maryland.

# Strategy in 2000 and Beyond

In the future, Constellation Energy expects to derive almost two-thirds of its earnings from competitive markets that are not limited by franchise boundaries. The focus of our strategy, therefore, has shifted to the growing national wholesale energy market, while also emphasizing the delivery of energy to our Central Maryland retail customers. The steps we're taking to accomplish this include preparing for customer choice and building a merchant energy company that serves the national wholesale market.



## We're Building a Merchant Energy Organization

Our growth strategy centers on the domestic wholesale energy market. This year, Constellation Power Source will take the next steps in building a full-scale merchant energy business by bringing together our power marketing, plant development, and plant operations. And it will align our 6,200 megawatts of existing utility generating assets in the mid-Atlantic region with our national power marketing and risk management capabilities.

Our approach to this business is different from that of our competitors'. Some power marketers are pure traders or speculators—they bet on whether it will be hot next July in a particular area of the country. Like any gamble, it can pay off for those who bet right. But that is not the type of business we're building.

Using its marketing expertise, Constellation Power Source identifies customer opportunities across the United States and determines how best to capitalize on them. We then use a portfolio approach to decide the right mix of power plants to develop, own, and operate and how much generation to control under contract. This business model has worked well. It helps us maintain a balance between supply and demand in each region and optimizes our capital investments in power plants.

## Investing Today to Gain Advantage

To promote growth in our domestic merchant energy business, we're committed to significant new capital investment over the next several years. We have placed orders for 5,100 megawatts of turbines including 800 megawatts of peaking units—generating plants that are used during high periods of demand—to come on-line in 2001. We now have 17 power project sites under active development.

With our concentration on domestic projects, we will make a controlled exit from our Latin American investments when market conditions warrant.

## Remaining a Regional Leader

We've been serving the energy needs of Central Maryland for nearly two centuries and have always had a strong corporate presence in the community. As Constellation Energy Group, we intend to remain a major local employer, continuing to serve our local customers while developing a Baltimore-based business that serves wholesale customers throughout the United States.

As we make this transition, BGE, our regulated utility, will continue to deliver energy reliably and affordably to our local customers. At the same time, our other nonregulated affiliates will continue to provide a variety of competitive energy products and services to retail and business customers throughout the region.

## Thanks to Ed Crooke

During the last several years, we've learned a lot about our competitive strengths and how we can use them to create new business opportunities. Through the process, we've developed a focus that will keep us positioned to take advantage of opportunities that leverage those strengths and avoid those markets or business sectors that don't. I want to express my sincere personal thanks to Ed Crooke for his tireless efforts in helping us get to this point.

Ed energized our strategic planning efforts, sharpening our focus and building on our strengths. Ed retired as Vice Chairman at the end of 1999 after 31 years of service. His counsel and guidance have helped to create a blueprint that will guide Constellation Energy Group and its employees as we become a major player in the domestic energy business.

## We're Determined and Winning!

We said last year that we were "determined to win" in the competitive energy market. That hasn't changed. During 1999, our employees proved their determination every day as we continued our aggressive evolution into the type of company that can thrive and prosper in the deregulated merchant energy market.

I want to thank all of our employees who delivered day in and day out to help us get to this point. We still have a lot of work ahead. But by the end of 2000 we will have transformed Constellation Energy Group into an entirely new energy company, streamlined in structure and focused on sustained growth in total shareholder return.

CHPoindexter

Christian H. Poindexter

*Chairman of the Board, President*
*and Chief Executive Officer*
*February 20, 2000*

## Highlights of Maryland PSC's Settlement Order on BGE's Transition Plan

Constellation Energy Group moved a step closer to implementing its competitive business strategy when the Maryland Public Service Commission approved BGE's Settlement Transition Plan on November 10, 1999.

The approval of the plan also supported two objectives of electric deregulation in Maryland: to develop a competitive retail electric market and to achieve a fair transition to competitive markets for all stakeholders.

Following are the major provisions of the PSC's Settlement Transition Order:

- Beginning with the first meter reading on or after July 1, 2000, most customers can choose their electric supplier. BGE will continue to deliver the energy to all customers in areas it traditionally serves.
- Also on July 1, BGE will reduce annual residential electric rates by about 6.5 percent, about $54 million, and then freeze those rates for six years. For residential customers who do not choose another electricity supplier, BGE will provide their electricity supply at fixed rates for up to six years under its Standard Offer Service.
- Electric distribution rates will be frozen for a four-year period for industrial and commercial customers. Also, industrial customers will be able to choose from four payment options that will fix the electric energy rates and transition charges for a period of time.
- Already incorporated into these rates is a competitive transition charge, which will allow the company to recover $528 million (after tax) of investments that had been made to meet regulatory obligations.
- Starting on July 1, generation supply will be deregulated. BGE, upon receiving all regulatory approvals, will transfer its generation assets to Constellation Energy Group's nonregulated affiliate companies.
- BGE will itemize rates and show separate components on its bill for delivery service, transition charges, standard offer service, transmission, universal service, and taxes.
- BGE will be the default supplier, providing service for customers whose contracted electricity is not delivered or who choose to return to BGE for supply.
- BGE will reduce its generation assets by $150 million between July 1, 1999 and June 30, 2000.
- Universal service will be provided for low-income customers without increasing their bills.

# Merchant Energy:

## A Power Source for the Future

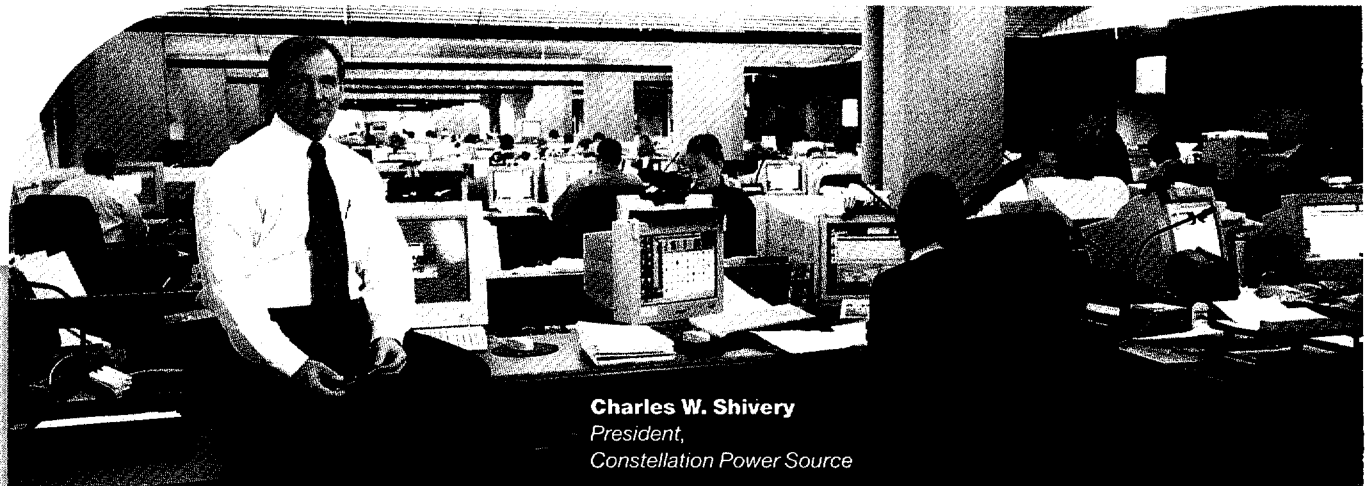
**Vision:** *Be a premier player in the wholesale merchant energy business in North America by providing customers with unparalleled service and creative solutions to their energy and risk management requirements.*



C3

*"The wholesale power market is a $200 billion market that's only going to grow larger. We're putting the pieces in place to be able to profit from that growth."*

*Charles W. Shivery*
*President, Constellation Power Source*



**Charles W. Shivery**
*President,*
*Constellation Power Source*

*Getting results in a new market requires new solutions, new directions, and new beginnings.*

*The Constellation Energy Group's move to the new energy market took a big step in 1997 when we created our Constellation Power Source subsidiary. From the outset, Constellation Power Source was built to buy, sell, and trade energy in the wholesale power market. But that was only a start.*

*As we move into the competitive market, Constellation Power Source is using the results and experience it's gained to build a merchant energy company that will be our power source for the future.*

**Building a Merchant Energy Company**

If results are beginnings, then the story of Constellation Energy's future starts with Constellation Power Source.

In just over two years, Constellation Power Source has moved from a start-up energy marketing company to being named 1999's "Best Power Marketer" by PHB Hagler Bailly, an international energy consulting company.

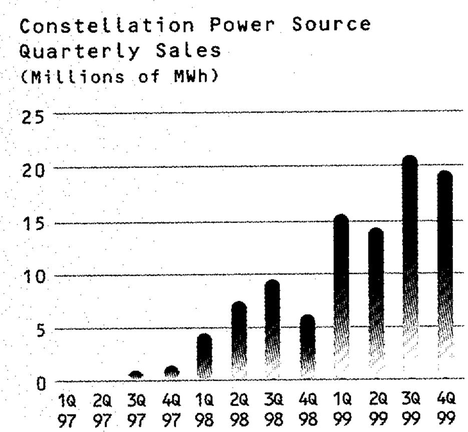
In 2000, Constellation Power Source will go even further, bringing together existing pieces from the Constellation Energy Group to form one of the nation's premier merchant energy companies. Constellation Power Source will no longer be simply an energy marketing company, but a merchant energy company. We are combining the existing power marketing and trading functions under Constellation Power Source with plant operations, development, and generation functions under our Constellation Power and BGE subsidiaries.

Together these functions will form an integrated merchant energy company that will strategically develop, own, and operate power plants; market and trade power; and manage risk in the wholesale energy market.

## Getting There With Results

To pursue a merchant energy strategy, we needed results to prove we were going in the right direction, and Constellation Power Source delivered them.

In 1999, it more than quadrupled its contribution to our earnings from the previous year to $0.23 per share, increased its asset base by $235 million, and increased its market share in high-energy growth areas such as Texas and the Midwest. Constellation Power Source has also captured a significant share of the standard offer electric supply service in New England. In the past year we doubled the size of our state-of-the-art power trading floor to pursue more opportunities in the wholesale energy market.



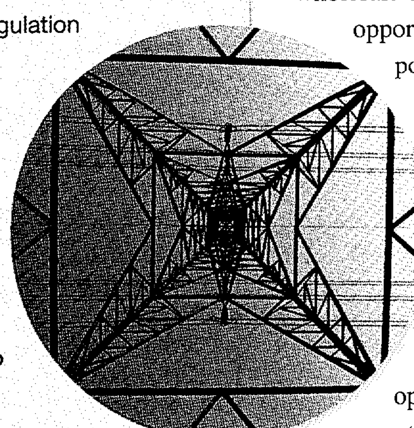

### What is the wholesale energy market?

For companies like Constellation Power Source, the wholesale energy market is a rapidly evolving place where electric industry change is creating new opportunities every day.

It began several years ago as a way for electric producers to sell excess energy to wholesale customers. As states across the country began deregulating their electric utilities, the wholesale market has moved to a new level.

In a regulated market, utilities and other power providers produce their power and sell it directly to their retail customers. But with deregulation of the energy supply part of the business, utilities are now deciding, or being legislated, to no longer generate power. That means businesses such as electric cooperatives, power marketers, municipalities, and utilities are going to the wholesale market to purchase power they'll then resell to their customers.

Bottom line, in 1999 the wholesale energy market was estimated to be worth $200 billion. But as more states move ahead with electric deregulation, electric power will be purchased almost exclusively from the wholesale market. For the future, that means growth in both customers and opportunity.



To achieve results, Constellation Power Source is building its business from its customer's perspective. Its success has been based on understanding precisely what a customer's energy needs are, then providing the best solution.

Ultimately that solution requires Constellation Power Source to provide electricity. To do that, it chooses from a number of options including purchasing power from regional power pools, developing bilateral agreements with third parties to provide energy, producing power in plants we own, or contracting for power directly from other suppliers.

## The Power Behind Our Future—Generation

As deregulation takes hold in states across the country, the wholesale energy market will expand rapidly. So, too, will opportunities to structure energy deals to meet the power requirements of wholesale customers such as municipalities, cooperatives, power plant owners, and other utilities.

To ensure that we have affordable and reliable energy to meet customers' needs, we're moving our fossil fuel power plants under the Constellation Power Source umbrella.

One of the many reasons we chose to pursue opportunities in the wholesale energy market is the operating strength of our fossil plants. Meeting the complex energy needs of large wholesale customers means, in many cases, ensuring we have cost-efficient and reliable power that's available when we need it. Over the past several years as they've prepared for the competitive market, our fossil fuel plants and employees have posted impressive productivity gains and proven they're ready to meet the challenge.

For the tenth consecutive year, our fossil fuel plants in 1999 set a new generation record producing 19.4 million megawatt-hours. Our employees did it safely, achieving one of the best safety records in our region.

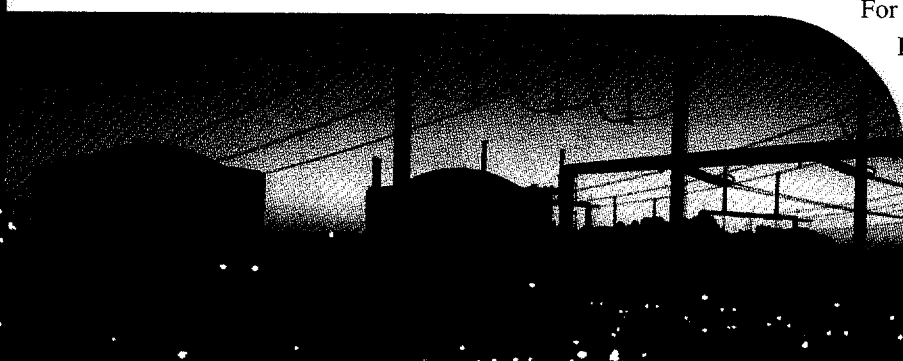
In addition to incorporating BGE's existing fossil plants to support power marketing and trading activities, Constellation Power Source is also looking to add generating assets in strategic locations. Last year, Constellation Power Source committed capital to fund an additional 5,100 megawatts of generating capacity in strategic growth areas.

Constellation Power Source has already brought under its umbrella the domestic independent power plants developed by our Constellation Power, Inc., subsidiary. Constellation Power, which has been operating in nonregulated power markets since 1985, brings a wealth of competitive experience as well as direct ownership positions in 28 energy projects located throughout the United States.

Together with Goldman Sachs, Tokyo Electric Power Company, Inc., and Mitsubishi Corporation, we continue our investment interest in Orion Power Holdings, Inc., which buys existing power plants. With acquisitions announced last year, Orion's portfolio will have more than 5,200 megawatts of generating capacity throughout the Northeast and Upper Midwest regions of the United States.

## Constellation Nuclear Group—Powerful Experience in a New Market

For more than 20 years, our Calvert Cliffs Nuclear Power Plant has provided a supply of cost-efficient energy for our customers. But that's only a beginning. Because it's a cost-efficient and clean energy source, nuclear power will continue to play a role in the deregulated power market.



## Generating Results at Our Power Plants

Our generating plants produced more than electricity in 1999—they produced competitive results.

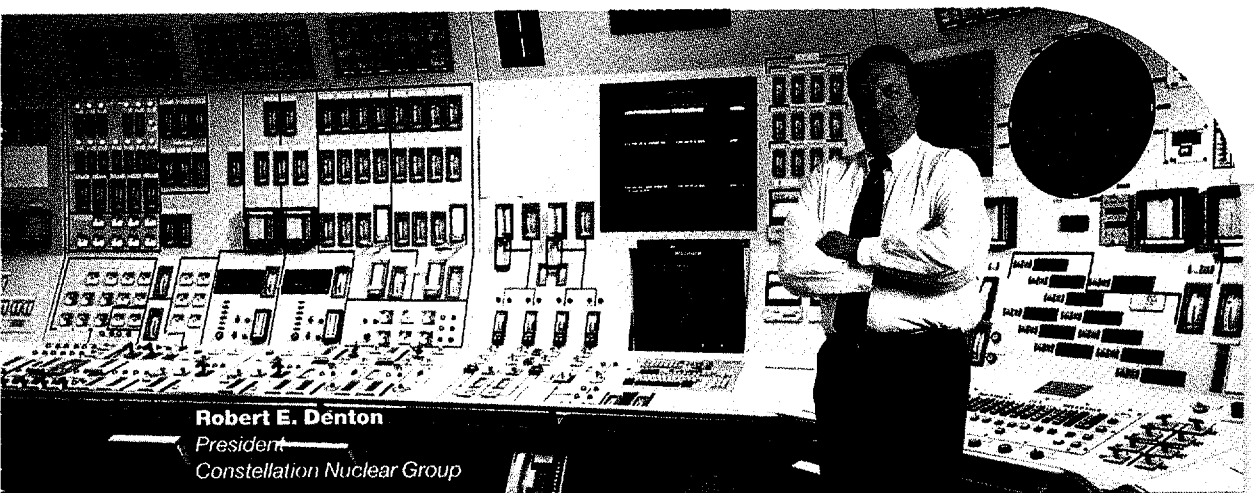
The power behind our merchant energy strategy comes, in part, from BGE's generating plants. On July 1, 2000, BGE's fossil fuel power plants and the Calvert Cliffs Nuclear Power Plant are expected to become part of our nonregulated subsidiaries. From that time on, the power they produce will be managed by our Constellation Power Source merchant energy company for the wholesale power market.

On the way to that new market, our employees have worked to ensure our plants continue to improve so they're ready to generate safe, efficient, and competitively priced power. Generation highlights from 1999 included:

- Our fossil and nuclear plants combined set an all-time generation record for the second consecutive year, producing 32.7 million megawatt-hours—about a 1% increase over last year's record production.
- After registering the lowest accident rate in the region in 1998, our fossil fuel plants continued to improve on safety, finishing the year with an OSHA rate of 1.32 accidents per 100 employees for the year—the best safety numbers in their history.
- For the first time ever our Calvert Cliffs Nuclear Power Plant received the highest rating given by the Institute of Nuclear Power Operations, which highlighted safety and teamwork as plant strengths.
- Calvert Cliffs' license renewal efforts took several major steps forward, as the Nuclear Regulatory Commission concluded there are neither safety nor environmental issues standing in the way of extending the plant's operating licenses an additional 20 years. The new operating licenses are expected to be issued this year.

*"Nuclear power has an important role to play as we carry out our overall merchant energy strategy. It is clean, reliable, cost-effective, and adds to the diversity of our fuel mix—all competitive advantages in the new energy market."*

*Robert E. Denton*
*President, Constellation Nuclear Group*



**Robert E. Denton**
*President*
*Constellation Nuclear Group*

When electric deregulation takes effect in Maryland, the Calvert Cliffs Nuclear Power Plant will be moved under the unregulated umbrella of our new afiliate, the Constellation Nuclear Group, LLC. Power produced by Calvert Cliffs will be managed by our Constellation Power Source subsidiary.

In preparing itself for this new market, Calvert Cliffs also has produced impressive results. In 1999, the plant generated a near-record 13.3 million megawatt-hours. And, for the first time ever, it received the highest rating given by the Institute of Nuclear Power Operations, which highlighted safety and teamwork as plant strengths.

In addition to nuclear generating capacity, Constellation Nuclear Group also includes our Constellation Nuclear Services subsidiary. Formed in 1999, it provides nuclear consulting services specializing in nuclear power plant license renewal and life-cycle management.

Calvert Cliffs was the first nuclear plant in the United States to apply to the Nuclear Regulatory Commission for renewal of its operating licenses. From this effort, we've gained critical experience other power companies can use.

So far, Constellation Nuclear Services has signed 13 contracts with six utilities and two energy industry groups for license renewal and life-cycle related work.

### Building A Bright Future

With our experience and accomplishments in both generation and wholesale power marketing and trading, we're building on a solid foundation for success in the competitive market.

Moving forward, we will be able to meet customers' complex energy needs through structured transactions, manage their energy risks, and develop, own, and operate power plants that support our overall business.

That means we're not just building a premier merchant energy company, we're building a bright future for our customers, shareholders, and us.

# BGE: Focused on Delivering Energy and Value

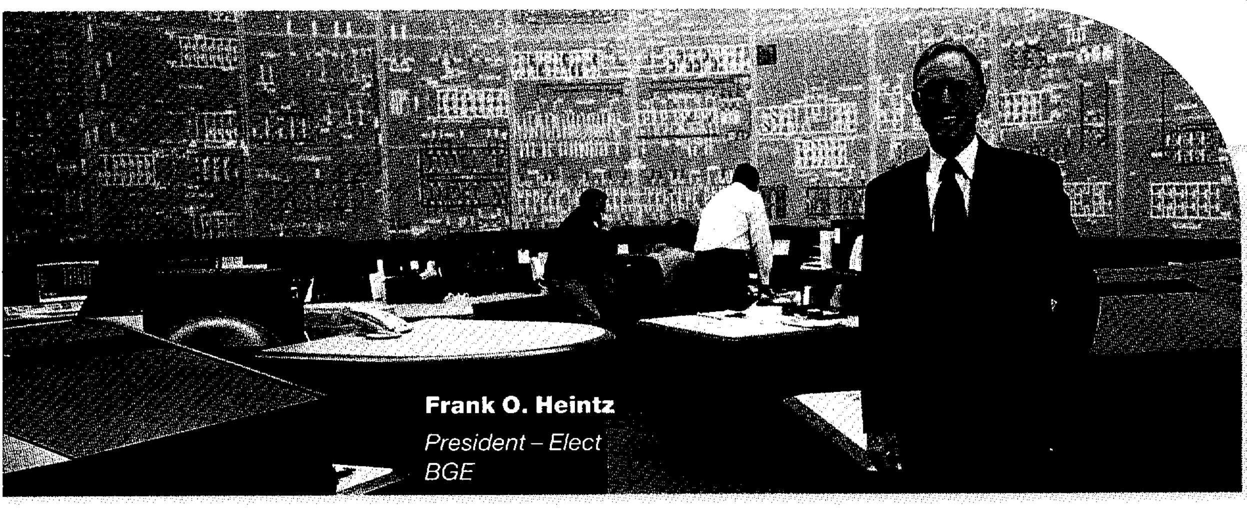
**Vision:** *To be a recognized leader in energy delivery services by enhancing customers' quality of life, shareholders' value, and employees' well-being.*



C4

*"BGE is truly a public service company, delivering the electricity and natural gas that are the lifeblood of Central Maryland's economy. Before, during, and after deregulation, our employees will continue to deliver the vital energy services our 1.1 million electric customers and 584,000 gas customers depend on."*

*Frank O. Heintz*
*President-Elect*
*BGE*



**Frank O. Heintz**
*President – Elect*
*BGE*

*No doubt, 1999 was a landmark year for both Maryland and BGE. Most important, the fundamental rules for deregulating Maryland's energy industry were set. Last year's results are dramatically changing the role of the local gas and electric utility. The changes ahead mark both an end and a beginning for BGE.*

*What ends is BGE's 90-year monopoly on both supplying and delivering energy to its Central Maryland customers. What begins is a company completely dedicated to the delivery of energy. In adapting to the new role in Maryland's energy market, BGE is taking another step in its 184-year evolution.*

### Next Step in a 184-Year Evolution

As of November 1, 1999, all BGE natural gas customers could choose their gas supplier. On July 1, 2000, the same will happen for all BGE electric customers. While customers may choose another energy supplier, BGE will continue to deliver natural gas and electricity through its pipes and wires to their homes and businesses in Central Maryland.

While deregulation will change the role the utility has played over the past century, it won't change BGE's core mission—delivering safe, economical, reliable, and profitable energy to its customers—something it's been doing for 184 years.

### Navigating the Challenges

There is no question that given the challenges that deregulation presents, BGE has its work cut out for it in the years ahead. Within the context of a 6.5% residential electric delivery rate reduction, six-year rate freeze, and meeting its standard offer service obligations *(see Settlement Order Highlights, page 6)*, BGE must achieve corporate profitability targets while maintaining and improving customer satisfaction, system safety, and reliability.

Yet, it enters its new era well prepared for successful operations. It has spent years getting ready for operating in a deregulated environment. Now that many of the rules have been set, our BGE team is more focused than ever.

### Preparing for Customer Choice

Since 1997, our BGE employees have been working toward a deadline that was set just last year—July 1, 2000. That's when Marylanders can choose their electric supplier and BGE's primary role will be to deliver that supply over its wires. Ensuring our systems are ready and customers are educated about their energy choices remain our top priorities and biggest challenges.

As active participants in the numerous Maryland Public Service Commission roundtables and technical groups, our employees have been working through the regulatory details to draw a blueprint for how customer choice will work. At the same time, they have been designing and building the infrastructure necessary to support our new responsibilities under customer choice.

In the new era, our employees will be responsible for enrolling customers who have chosen other suppliers. They will also have to support competitive billing and unbundling of the current electric bill as well as settle load and capacity obligations between BGE, other suppliers, and the Pennsylvania-New Jersey-Maryland Interconnection—the power grid we operate in.

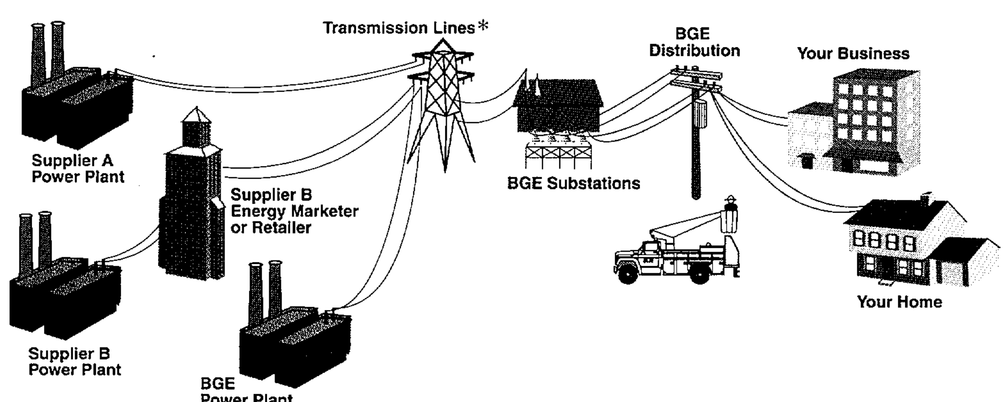
## How Deregulation is Changing the Electric Utility Industry

Maryland has now joined the growing number of states that are deregulating their electric generation industry and opening it to competition. That means, beginning in July 2000, BGE customers will, for the first time, be able to choose the company that supplies their electricity. BGE will remain the local distribution company, delivering that power reliably and safely to homes and businesses in Central Maryland.

### Electric Customer Choice—The Basics

There are two major activities in the electric utility industry: the generation of power supply and the delivery of that supply to customers.

**Power Generation: Open to Competition** **Power Delivery: Still Regulated and Handled by BGE**




**Power Supply:** This is the portion of the electric business that will be open to competition. Electricity is generated by power plants and transmitted over high-voltage lines to local distribution systems. With deregulation, customers can choose to buy electricity from a number of different suppliers including other utilities, energy marketers or retailers, or BGE.

* Transmission rates will remain regulated by the Federal Energy Regulatory Commission.

**Power Delivery and Restoration:** Once electricity reaches BGE's distribution system, it's delivered to homes or businesses over our power lines. While customers can choose another supplier, BGE will continue to be responsible for maintaining the lines that deliver the power. BGE will also continue to restore power after service interruptions and provide emergency services.

To meet these requirements, the team is extending the capabilities of our Customer Information System, developing new e-commerce interfaces with electricity suppliers, and implementing a new system to support load and capacity settlement. Also we have designed a newly itemized bill and are working with the state to educate consumers so they can make informed choices.

### Focused on Reliability, Power Quality and Costs

Today the standards for power quality and service reliability are higher than they've ever been. That's because in the digital age, a split-second loss of power can shut down an entire production line. To provide customers the quality of service they require, we have been improving our delivery systems. Using new technology, we are increasing reliability and power quality while reducing costs.

An example is our award-winning System Control Integration Program, which brings substation monitoring and control systems into the 21st century. A team of employees designed and built what has become the prototype for future BGE substations. The program automatically gives our system planners, operators, and analysts the real-time and historical data they need. It also measures the quality of the power supply, improving our ability to deliver the reliable, clean energy today's customers require. In addition to these benefits, this program reduces substation construction and maintenance costs because there are fewer components and less to maintain once it's built.

### Focused on Preventing Outages and Improving Restoration after Storms

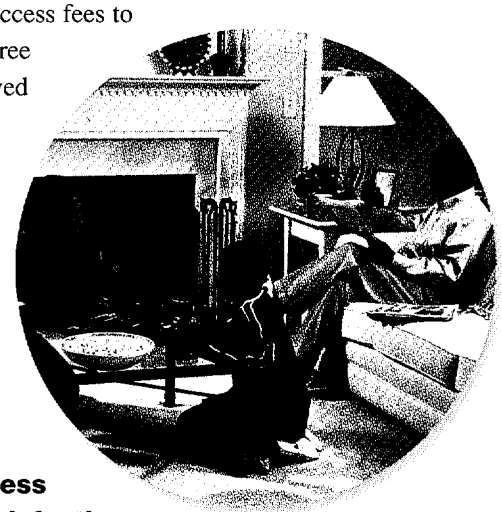
We continue to direct our focus from responding to outages to preventing them. Over the last five years, we have invested about $285 million to improve overall electric system performance. Notably, from 1994 to 1998, we reduced the average number of service interruptions by 36%.

Even with these improvements, BGE's Utility Operations Group last year faced one of its most challenging years ever for weather-related events. A devastating ice storm hit in January. Then the wrath of Hurricane Floyd in September caused the worst damage to our system in company history.

Our employees responded in heroic fashion to both of these events. Hurricane Floyd's "once-in-a-lifetime" damage to the electric distribution system tested the limits of our people, our storm management organization, and our customers. It also taught us some valuable lessons in what we need to do to meet customers' expectations during major outages. As a result, we are implementing significant changes to our processes and systems to shorten restoration time and provide customers with better information about our progress.

### Meeting Demand for Natural Gas Delivery

There has been tremendous growth in demand for natural gas hookups over the past few years, and we've expanded our system to respond to it. Since January 1997, our gas employees have added more than 28,000 new homes and collected increased access fees to do that. In the last three years, they've achieved a nearly 7% annual growth in operating income. They have achieved this growth while keeping gas rates economical for our customers.



### Measuring Success by Customer Satisfaction

The result of all of our efforts is ultimately measured by customers' satisfaction with our service. That's why we keep a close eye on how our customers rate us and how we rank when compared with national benchmarks.

Over the years BGE employees have met the high standards set by customers, maintaining consistently high satisfaction ratings from residential customers and performing well above the national average when compared with other investor-owned utilities. We have also seen marked improvement in how small business and large industrial customers view us, a record we continue to work to improve.

After deregulation of the supply side of the business, we will be an energy delivery company, serving marketers and suppliers as well as our traditional customer base. To reflect these changes, we are now expanding and modifying our customer satisfaction monitoring. Now, more than ever, we need to know how we are measuring up in our customers' eyes.

*Ultimately, a company is only as good as its employees. Likewise, a community is only as strong as its citizens and businesses.*

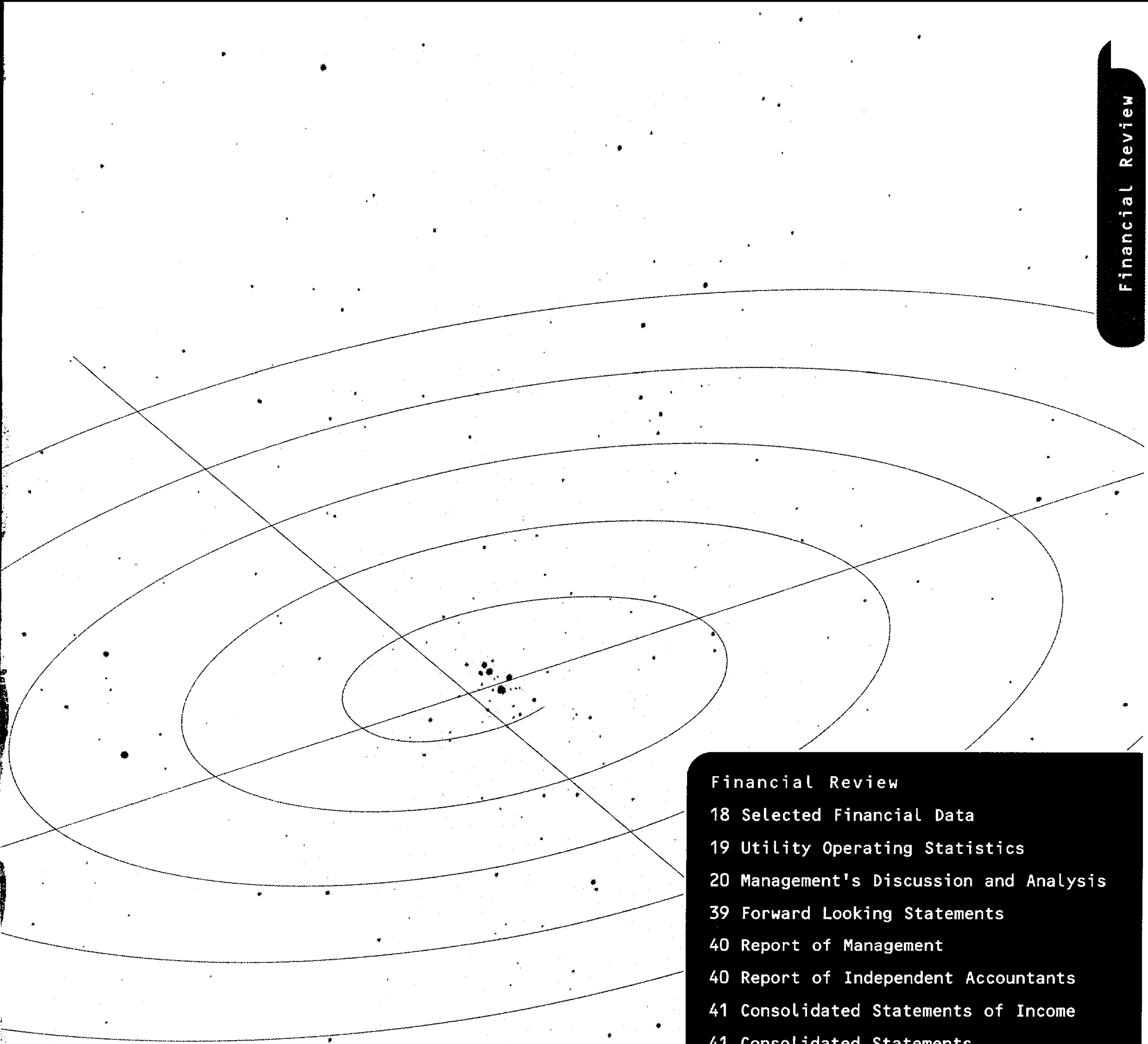
# *Generating* **Success** *with* *Powerful* **Partnerships**

*Throughout its long history, BGE and its employees have formed powerful partnerships for positive change with the communities we serve. We begin 2000 as Constellation Energy Group, a strong company committed to building on BGE's legacy of serving customers, supporting the community, and preserving the environment for future generations.*

**Here's a look at some of what we've done:**

- Constellation Energy Group and its employees led Maryland companies in both United Way and March of Dimes giving. We contributed more than $2.3 million to the United Way, and our $105,000 contribution to the March of Dimes was tops in the state.
- Our corporate contributions program remained a leader, evaluating and responding to 1,650 requests for support, and donating over $5 million to programs that provide for those less fortunate and enrich the quality of life in Maryland.
- Our employees have always rolled up their sleeves to help where help is needed. In fact, over the past two years they donated more than 8,000 pints of blood to the Red Cross, provided more than 21,000 hours of community service, and raised more than $300,000 for various nonprofit groups in Maryland.
- In 1994, to help children start school ready to learn, we established the Early Childhood Development grant program. As our program continues, we've donated more than $3 million to assist early childhood education programs in Maryland.
- To recognize our 1998 recycling efforts, the Environmental Protection Agency in 1999 named BGE a WasteWise Program Champion. During that period we recycled 562 tons of paper, 599 tons of aluminum, and 750 tons of utility poles.
- Always innovating, employees at our coal-fired power plants have developed a variety of ways to manage coal ash in an environmentally sound manner. Last year, our Brandon Shores plant opened a unique ash processing facility. Owned and operated by Separation Technologies, Inc., it produced more than 30,000 tons of low-carbon ash that was then marketed to ready-mix concrete companies. Next year's goal is 120,000 tons.

***At our PowerFest '99 celebration, employees opened the gates and hosted a full day of fun and educational events for more than 1,500 residents who live near our Brandon Shores/Wagner power plant.***



Financial Review

# Selected Financial Data

| | 1999 | 1998 | 1997 | 1996 | 1995 | Compounded Growth 5-Year | 10-Year |
|---|---|---|---|---|---|---|---|
| | *(Dollar amounts in millions, except per share amounts)* | | | | | | |
| **Summary of Operations** | | | | | | | |
| Total Revenues | **$3,786.2** | $3,358.1 | $3,307.6 | $3,153.2 | $2,934.8 | 6.35% | 6.42% |
| Operating Expenses | **3,026.3** | 2,617.0 | 2,584.0 | 2,483.7 | 2,239.1 | 7.10 | 6.88 |
| Income From Operations | **759.9** | 741.1 | 723.6 | 669.5 | 695.7 | 3.65 | 4.78 |
| Other Income (Expense) | **7.9** | 5.7 | (52.8) | 6.1 | 8.8 | (24.55) | (12.75) |
| Income Before Fixed Charges and Income Taxes | **767.8** | 746.8 | 670.8 | 675.6 | 704.5 | 2.84 | 4.23 |
| Fixed Charges | **255.0** | 262.7 | 258.7 | 237.0 | 237.6 | 2.09 | 3.43 |
| Income Before Income Taxes | **512.8** | 484.1 | 412.1 | 438.6 | 466.9 | 3.22 | 4.65 |
| Income Taxes | **186.4** | 178.2 | 158.0 | 166.3 | 169.5 | 3.91 | 8.61 |
| Income Before Extraordinary Item | **326.4** | 305.9 | 254.1 | 272.3 | 297.4 | 2.84 | 2.96 |
| Extraordinary Loss, Net of Income Taxes | **(66.3)** | – | – | – | – | | |
| Net Income | **$ 260.1** | $ 305.9 | $ 254.1 | $ 272.3 | $ 297.4 | (1.72) | 0.65 |
| Earnings Per Share of Common Stock and Earnings Per Share of Common Stock— Assuming Dilution Before Extraordinary Item | **$ 2.18** | $ 2.06 | $ 1.72 | $ 1.85 | $ 2.02 | 2.47 | 0.72 |
| Extraordinary Loss, Net of Income Taxes | **(.44)** | – | – | – | – | | |
| Earnings Per Share of Common Stock and Earnings Per Share of Common Stock— Assuming Dilution | **$ 1.74** | $ 2.06 | $ 1.72 | $ 1.85 | $ 2.02 | (2.05) | (1.53) |
| Dividends Declared Per Share of Common Stock | **$ 1.68** | $ 1.67 | $ 1.63 | $ 1.59 | $ 1.55 | 2.16 | 1.99 |
| **Summary of Financial Condition** | | | | | | | |
| Total Assets | **$9,683.8** | $9,275.0 | $8,900.0 | $8,678.2 | $8,419.1 | 4.25 | 5.30 |
| Capitalization | | | | | | | |
| Long-term debt | **$2,575.4** | $3,128.1 | $2,988.9 | $2,758.8 | $2,598.2 | (0.07) | 2.18 |
| Preferred stock | – | – | – | – | 59.2 | | |
| Redeemable preference stock | – | – | 90.0 | 134.5 | 242.0 | | |
| Preference stock not subject to mandatory redemption | **190.0** | 190.0 | 210.0 | 210.0 | 210.0 | 4.84 | 5.62 |
| Common shareholders' equity | **2,993.0** | 2,981.5 | 2,870.4 | 2,854.7 | 2,811.2 | 1.94 | 4.11 |
| Total Capitalization | **$5,758.4** | $6,299.6 | $6,159.3 | $5,958.0 | $5,920.6 | (0.12) | 2.34 |
| **Financial Statistics at Year End** | | | | | | | |
| Ratio of Earnings to Fixed Charges | **2.87** | 2.60 | 2.35 | 2.44 | 2.52 | | |
| Book Value Per Share of Common Stock | **$ 20.01** | $ 19.98 | $ 19.44 | $ 19.33 | $ 19.06 | | |
| Number of Common Shareholders *(In Thousands)* | **66.1** | 69.9 | 73.7 | 77.6 | 79.8 | | |

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

# Utility Operating Statistics

| | 1999 | 1998 | 1997 | 1996 | 1995 | Compounded Growth 5-Year | 10-Year |
|---|---|---|---|---|---|---|---|
| **Electric Operating Statistics** | | | | | | | |
| Revenues *(In Millions)* | | | | | | | |
| Residential | **$ 975.2** | $ 948.6 | $ 932.5 | $ 958.7 | $ 955.2 | 0.92% | 4.16% |
| Commercial | **939.3** | 912.9 | 892.6 | 861.3 | 879.4 | 1.95 | 3.45 |
| Industrial | **204.3** | 211.5 | 211.9 | 207.6 | 208.5 | (0.13) | 0.63 |
| System Sales | **2,118.8** | 2,073.0 | 2,037.0 | 2,027.6 | 2,043.1 | 1.26 | 3.45 |
| Interchange and Other Sales | **112.1** | 120.8 | 132.7 | 155.9 | 167.0 | (1.02) | 20.20 |
| Other | **29.1** | 27.0 | 22.3 | 25.5 | 21.0 | 8.79 | 3.87 |
| Total | **$2,260.0** | $2,220.8 | $2,192.0 | $2,209.0 | $2,231.1 | 1.22 | 3.86 |
| Sales *(In Thousands)*—MWH | | | | | | | |
| Residential | **11,349** | 10,965 | 10,806 | 11,243 | 10,966 | 1.24 | 1.85 |
| Commercial | **13,565** | 13,219 | 12,718 | 12,591 | 12,635 | 1.89 | 2.05 |
| Industrial | **4,350** | 4,583 | 4,575 | 4,596 | 4,591 | (0.38) | 0.21 |
| System Sales | **29,264** | 28,767 | 28,099 | 28,430 | 28,192 | 1.29 | 1.67 |
| Interchange and Other Sales | **4,785** | 5,454 | 6,224 | 7,580 | 8,149 | (3.38) | 23.18 |
| Total | **34,049** | 34,221 | 34,323 | 36,010 | 36,341 | 0.54 | 2.98 |
| Customers *(In Thousands)* | | | | | | | |
| Residential | **1,021.4** | 1,009.1 | 1,001.0 | 995.2 | 988.2 | 0.86 | 1.12 |
| Commercial | **107.7** | 106.5 | 105.9 | 104.5 | 103.4 | 1.11 | 1.25 |
| Industrial | **4.7** | 4.6 | 4.5 | 4.3 | 4.1 | 3.28 | 4.25 |
| Total | **1,133.8** | 1,120.2 | 1,111.4 | 1,104.0 | 1,095.7 | 0.89 | 1.14 |
| Average Use per Residential Customer—KWH | **11,111** | 10,866 | 10,794 | 11,297 | 11,097 | 0.38 | 0.72 |
| Average Rate per KWH (System Sales)—¢ | | | | | | | |
| Residential | **8.59** | 8.65 | 8.63 | 8.53 | 8.71 | (0.32) | 2.26 |
| Commercial | **6.92** | 6.91 | 7.02 | 6.84 | 6.96 | 0.03 | 1.37 |
| Industrial | **4.70** | 4.62 | 4.63 | 4.52 | 4.54 | 0.26 | 0.44 |
| Peak Load (One-Hour)—MW | **6,383** | 6,045 | 5,980 | 5,955 | 5,947 | 1.12 | 1.87 |
| Capability at Summer Peak—MW | **6,522** | 6,422 | 6,741 | 6,800 | 6,731 | (0.60) | 0.57 |
| System Load Factor | **55.7%** | 57.4% | 56.9% | 57.5% | 57.2% | 0.36 | (0.30) |
| **Gas Operating Statistics** | | | | | | | |
| Revenues *(In Millions)* | | | | | | | |
| Residential —Excluding Delivery Service | **$ 298.1** | $ 279.2 | $ 321.7 | $ 320.1 | $ 248.3 | 2.56 | 2.09 |
| —Delivery Service | **11.5** | 4.9 | 0.5 | – | – | | |
| Commercial—Excluding Delivery Service | **79.3** | 75.6 | 113.5 | 125.1 | 109.9 | (8.10) | (3.45) |
| —Delivery Service | **24.4** | 19.4 | 12.9 | 7.2 | 3.7 | 60.37 | 18.68 |
| Industrial —Excluding Delivery Service | **8.2** | 8.0 | 11.4 | 17.1 | 16.7 | (16.50) | (7.76) |
| —Delivery Service | **16.1** | 16.0 | 17.2 | 14.6 | 16.3 | 10.89 | (3.38) |
| System Sales | **437.6** | 403.1 | 477.2 | 484.1 | 394.9 | 1.03 | 0.89 |
| Off-System Sales | **42.9** | 40.9 | 37.5 | 26.6 | – | | |
| Other | **7.7** | 7.2 | 6.9 | 6.6 | 5.6 | 7.35 | (3.76) |
| Total | **$ 488.2** | $ 451.2 | $ 521.6 | $ 517.3 | $ 400.5 | 3.00 | 1.72 |
| Sales *(In Thousands)*—DTH | | | | | | | |
| Residential —Excluding Delivery Service | **34,272** | 33,595 | 39,958 | 43,784 | 40,211 | (3.18) | (1.49) |
| —Delivery Service | **4,468** | 1,890 | 205 | – | – | | |
| Commercial—Excluding Delivery Service | **11,733** | 11,775 | 18,435 | 22,698 | 23,612 | (13.13) | (6.08) |
| —Delivery Service | **20,288** | 16,633 | 12,964 | 8,755 | 6,982 | 25.60 | 13.38 |
| Industrial —Excluding Delivery Service | **1,367** | 1,412 | 2,016 | 2,887 | 4,102 | (20.88) | (9.47) |
| —Delivery Service | **33,118** | 34,798 | 38,791 | 36,201 | 35,925 | (0.43) | (1.73) |
| System Sales | **105,246** | 100,103 | 112,369 | 114,325 | 110,832 | (0.65) | (0.50) |
| Off-System Sales | **15,543** | 16,724 | 14,759 | 9,968 | – | | |
| Total | **120,789** | 116,827 | 127,128 | 124,293 | 110,832 | 2.13 | 0.88 |
| Customers *(In Thousands)* | | | | | | | |
| Residential | **543.5** | 532.5 | 524.5 | 516.5 | 506.8 | 1.76 | 1.20 |
| Commercial | **39.9** | 39.6 | 39.3 | 38.9 | 38.4 | 1.03 | 1.09 |
| Industrial | **1.3** | 1.3 | 1.3 | 1.3 | 1.3 | – | (0.74) |
| Total | **584.7** | 573.4 | 565.1 | 556.7 | 546.5 | 1.70 | 1.19 |
| Average Use per Residential Customer (Excluding Delivery Service)—Therms | **631** | 631 | 762 | 848 | 794 | (4.85) | (2.65) |
| Average Rate per Therm—$ | | | | | | | |
| Residential (Excluding Delivery Service) | **.87** | .83 | .81 | .73 | .62 | 6.00 | 3.61 |
| Commercial (Excluding Delivery Service) | **.68** | .64 | .62 | .55 | .47 | 5.92 | 2.92 |
| Industrial (Excluding Delivery Service) | **.60** | .57 | .57 | .59 | .41 | 5.46 | 1.84 |
| Peak Day Sendout *(In Thousands)*—DTH | **727.8** | 658.4 | 765.0 | 709.0 | 706.3 | (0.91) | 0.93 |
| Peak Day Capability *(In Thousands)*—DTH | **836.6** | 833.0 | 870.0 | 870.0 | 847.0 | (0.25) | 0.95 |

*Utility operating statistics do not reflect the elimination of intercompany transactions.*

## Introduction

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

Constellation Energy's subsidiaries primarily include BGE and a group of energy services businesses focused mostly on power marketing and merchant generation 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.

Our energy services businesses are:

- Constellation Power Source,™ Inc.—wholesale power marketing,
- Constellation Power,™ Inc. and Subsidiaries—power projects,
- Constellation Energy Source,™ Inc.—energy products and services,
- Constellation Nuclear Group,™ LLC—nuclear generation and consulting services,
- BGE Home Products & Services,™ Inc. and Subsidiaries—home products, commercial building systems, and residential and small commercial gas retail marketing, and
- District Chilled Water General Partnership (ComfortLink®) —a general partnership, in which BGE is a partner, that provides cooling services for commercial customers in Baltimore.

Our other businesses are:

- Constellation Investments,™ Inc.—financial investments, and
- Constellation Real Estate Group,™ Inc.—real estate and senior-living facilities.

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.

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

- what factors affect our business,
- what our earnings and costs were in 1999 and 1998,
- why earnings and costs changed from the year before,
- where our earnings came from,
- how all of this affects our overall financial condition,
- what our expenditures for capital projects were in 1997 through 1999, and what we expect them to be in 2000 through 2002, 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 41, which present the results of our operations for 1999, 1998, and 1997. We analyze and explain the differences between periods by operating segment. Our analysis is important in making decisions about your investments in Constellation Energy.

Also, this discussion and analysis is based on the operation of the electric generation portion of our utility business under current rate regulation. The electric utility industry is undergoing rapid and substantial change. On April 8, 1999, Maryland enacted legislation authorizing customer choice and competition among electric suppliers. On November 10, 1999, the Maryland Public Service Commission (Maryland PSC) issued Order No. 75757 (Restructuring Order) approving a Stipulation and Settlement Agreement between BGE and a majority of the active parties involved in the electric restructuring proceeding that resolves the major issues surrounding electric restructuring. See the "Electric Restructuring" section on page 24 and Note 4 on page 58 for a detailed discussion of the Restructuring Order.

Our electric business will change significantly beginning July 1, 2000 as we enter into retail customer choice for electric generation and our generation assets are transferred to nonregulated subsidiaries of Constellation Energy. Accordingly, the results of operations and financial condition described in this discussion and analysis are not necessarily indicative of future performance.

## Strategy

The change toward customer choice will significantly impact our business going forward. In response to this change, we regularly evaluate our strategies with two goals in mind: to improve our competitive position, and to anticipate and adapt to regulatory change. We are realigning our organization combining all of our domestic merchant energy businesses. We will continue to invest in the growth of these businesses, with the objective of providing new sources of earnings in anticipation of lower electric utility revenues. In addition, we might consider one or more of the following strategies:

- the complete or partial separation of our transmission and distribution functions,
- the construction, purchase or sale of generation assets,
- mergers or acquisitions of utility or non-utility businesses,
- spin-off or sale of one or more businesses, and
- growth of earnings from other nonregulated businesses.

We cannot predict whether any of the strategies described above may actually occur, or what their effect on our financial condition or competitive position might be. However, with the shift toward customer choice, competition, and the growth of our nonregulated subsidiaries, various factors will affect our financial results in the future. These factors include, but are not limited to, operating our currently regulated generation assets in a deregulated market beginning July 1, 2000 without the benefit of a fuel rate adjustment clause, the loss of revenues due to customers choosing alternate suppliers, higher volatility of earnings and cash flows, and increased financial requirements of our nonregulated subsidiaries. Please refer to the "Forward Looking Statements" section on page 39 for additional factors.

## Current Issues

### Competition—Electric

Electric utilities are facing competition on various fronts, including:

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

On April 8, 1999, Maryland enacted legislation authorizing customer choice and competition among electric suppliers. In addition, on November 10, 1999, the Maryland PSC issued a Restructuring Order that resolved the major issues surrounding electric restructuring. These matters are discussed further in the "Electric Restructuring" section on page 24 and Note 4 on page 58.

As a result of the deregulation of BGE's electric generation, no earlier than July 1, 2000, and upon receipt of all regulatory approvals, we expect that BGE will transfer, at book value, its nuclear generating assets and its nuclear decommissioning trust fund to a subsidiary of Constellation Nuclear Group, LLC. In addition, we expect that BGE will transfer, at book value, its fossil generating assets and its partial ownership interest in two coal plants and a hydroelectric plant located in Pennsylvania to a nonregulated subsidiary of Constellation Energy. In total, these generating assets represent about 6,240 megawatts of generation capacity with a total projected net book value at June 30, 2000 of approximately $2.4 billion.

We expect BGE to transfer approximately $278 million of tax exempt debt to our nonregulated subsidiaries related to the transferred assets and that BGE will receive approximately $1.1 billion in unsecured promissory notes. Repayments of the notes by our nonregulated subsidiaries will be used exclusively to service certain long-term debt of BGE. BGE will also transfer equity associated with the generating assets to nonregulated subsidiaries of Constellation Energy.

Under the Restructuring Order, BGE will provide standard offer service to customers at fixed rates over various time periods during the transition period for those customers that do not choose an alternate supplier once customer choice begins July 1, 2000. In addition, the electric fuel rate will be discontinued effective July 1, 2000. Nonregulated subsidiaries of Constellation Energy will provide BGE with the energy and capacity required to meet its standard offer service obligations for the first three years of the transition period. Standard offer service will be competitively bid thereafter.

Nonregulated subsidiaries of Constellation Energy will obtain the energy and capacity to supply BGE's standard offer service obligations from the Calvert Cliffs Nuclear Power Plant (Calvert Cliffs) and BGE's former fossil plants, supplemented with energy purchased from the wholesale energy market as necessary. Our earnings will be exposed to the risks of the competitive wholesale electricity market to the extent that our nonregulated subsidiaries have to purchase energy and/or capacity or generate energy to meet obligations to supply power to BGE at market prices or costs, respectively, which may approach or exceed

BGE's standard offer service rates. We will also be affected by operational risk, that is, the risk that a generating plant is not available to produce energy when the energy is required.

Until July 1, 2000, we will continue to recover our cost of electric fuel as long as the Maryland PSC finds that, among other things, we have kept the productive capacity of our generating plants at a reasonable level. After July 1, 2000, any energy purchased to meet BGE's load commitments will become a cost of doing business in the newly competitive marketplace. Therefore, if BGE provides standard offer service at fixed rates to its customers that do not select an alternative provider as required under the terms of the Restructuring Order, and the load demand exceeds our capacity to supply energy due to a plant outage, we would be required to purchase additional power in the wholesale energy market. If the price of obtaining energy in the wholesale market exceeds the fixed standard offer service price, our earnings would be adversely affected. Imbalances in demand and supply can occur not only because of plant outages, but also because of transmission constraints or due to extreme temperatures (hot or cold) causing demand to exceed available supply.

We will use appropriate risk management techniques consistent with our business plan and policies to address these issues. We cannot estimate the impact of the increased financial risks associated with this transition. However, these financial risks could have a material impact on our, and BGE's, financial results.

**Competition—Gas**

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 industrial and commercial gas customers, and effective November 1, 1999, all BGE residential customers have the option to purchase gas from other suppliers.

**Early Retirement Program**

In recognition of the changing business environment, in 1999, our Board of Directors approved a Targeted Voluntary Special Early Retirement Program (TVSERP) to provide enhanced early retirement benefits to certain eligible participants in targeted jobs that elect to retire on June 1, 2000. The financial impacts of the TVSERP will be reflected in the second quarter of 2000.

**Calvert Cliffs License Extension**

In 1998, we filed an application with the Nuclear Regulatory Commission (NRC) for a 20-year license extension for Calvert Cliffs to extend its license beyond 2014 for Unit 1 and 2016 for Unit 2. License renewal evaluations focus on age-related issues in long-lived passive components (passive components include buildings, the reactor vessel, piping, ventilation ducts, electric cables, etc.). We must demonstrate that we can ensure that these passive components will continue to perform their intended functions through the renewal period. The NRC will also consider the impact of the 20-year license extension on the environment.

According to the NRC's timetable, approval of BGE's application is expected in April 2000. However, we cannot predict the actual timing of the NRC's decision, or the impact, if any, on our financial results. If we do not receive the license extension, we may not be able to operate the Calvert Cliffs units beyond 2014 and 2016.

BGE is currently involved in a lawsuit titled *National Whistleblower Center v. Nuclear Regulatory Commission and Baltimore Gas and Electric Company* regarding its license extension process. The matter involves an appeal of the NRC's dismissal of Whistleblower's petition to intervene in the license renewal proceeding. At issue was the NRC's adoption of a streamlined procedure for the proceeding, including the requirement that any requests for extensions of time be justified by a showing of "unavoidable and extreme circumstances" rather than the "good cause" standard previously applied. Applying the new standard, the NRC ultimately dismissed Whistleblower's petition to intervene. This matter is pending before the court.

**Environmental and Legal Matters**

You will find details of our environmental matters in Note 10 on page 69 and in our most recent Annual Report on Form 10-K under Item 1. Business—Environmental Matters. You will find details of our legal matters in our most recent Annual Report on Form 10-K under Item 3. Legal Proceedings. Some of the information is about costs that may be material to our financial results.

**Year 2000**

We did not experience any significant problems associated with the year 2000 issue.

**Accounting Standards Issued**

We discuss recently issued accounting standards in Note 1 on page 54.

## Results of Operations

In this section, we discuss our earnings and the factors affecting them. We begin with a general overview, then separately discuss earnings for our operating segments.

### Overview

*Total Earnings Per Share of Common Stock*

| | 1999 | 1998 | 1997 |
|---|---|---|---|
| Utility business | **$2.03** | $1.93 | $1.94 |
| Diversified businesses | **.45** | .27 | .34 |
| Total earnings per share before nonrecurring charges included in operations | **2.48** | 2.20 | 2.28 |
| Nonrecurring charges included in operations: | | | |
| Hurricane Floyd (see Note 2 on page 55) | **(.03)** | – | – |
| Write-off of merger costs (see Note 2 on page 55) | **–** | – | (.25) |
| Write-downs of power projects (see Note 3 on page 56) | **(.12)** | – | – |
| Write-off of energy services investment (see Note 2 on page 55) | **–** | (.04) | – |
| Write-down of financial investment (see Note 3 on page 57) | **(.11)** | – | – |
| Write-downs of real estate and senior-living investments (see Note 2 on page 55 and Note 3 on page 56) | **(.04)** | (.10) | (.31) |
| Total earnings per share before extraordinary item | **2.18** | 2.06 | 1.72 |
| Extraordinary loss (see Note 4 on page 59) | **(.44)** | – | – |
| Total earnings per share | **$1.74** | $2.06 | $1.72 |

### 1999

Our 1999 total earnings decreased $45.8 million, or $.32 per share, compared to 1998. Our total earnings decreased mostly because we recorded an extraordinary charge of $66.3 million, or $.44 per share, associated with the deregulation of the electric generation portion of our business. Our 1999 total earnings also include nonrecurring write-downs recorded in our power projects, financial investments, and real estate and senior-living businesses. These decreases were partially offset by higher earnings from utility and diversified business operations excluding nonrecurring charges. We discuss the extraordinary charge in Note 4 on page 59.

In 1999, we had higher utility earnings before the extraordinary charge compared to 1998 mostly because we sold more electricity and gas this year, and we settled a capacity contract with PECO Energy Company in 1998 that had a negative impact on earnings in that year. This increase was partially offset by storm restoration activities related to Hurricane Floyd and higher depreciation and amortization expense mostly due to the $75.0 million, or $48.8 million after-tax, amortization of the regulatory asset recorded in 1999 for the reduction of our generation plant under the Restructuring Order.

We discuss our utility earnings and the Restructuring Order in more detail in the "Utility Business" section on page 24.

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

We discuss our diversified business earnings, including the write-downs, further in the "Diversified Businesses" section beginning on page 31.

### 1998

Our 1998 total earnings increased $51.8 million, or $.34 per share, compared to 1997. Our total earnings increased mostly because 1997 results reflect our write-off of costs associated with the terminated merger with Potomac Electric Power Company, and our real estate and senior-living facilities business' write-down of its investments in two real estate projects. This increase was partially offset by:

- our real estate and senior-living facilities business' write-down of its investment in a real estate project in 1998, and
- the write-off of an energy services investment in 1998.

In 1998, utility earnings were about the same compared to 1997.

In 1998, diversified business earnings before nonrecurring charges decreased compared to 1997 mostly because of lower earnings from our real estate and senior-living facilities and financial investments businesses. This decrease was partially offset by higher earnings from our power projects and power marketing businesses.

## Utility Business

Before we go into the details of our electric and gas operations, we believe it is important to discuss factors that have a strong influence on our utility business performance: electric restructuring, regulation by the Maryland PSC, the weather, and other factors, including the condition of the economy in our service territory.

### Electric Restructuring

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

In the Restructuring Order discussed below, the Maryland PSC addressed the major provisions of the Act. The accompanying tax legislation is discussed in detail in Note 4 on page 58.

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

- All customers, except a few commercial and industrial companies that have signed contracts with BGE, will be able to choose their electric energy supplier beginning July 1, 2000. BGE will provide a standard offer service for customers that do not select an alternative supplier. In either case, BGE will continue to deliver electricity to all customers in areas traditionally served by BGE.
- BGE's current electric base rates are frozen at their current levels until July 1, 2000.
- BGE will reduce 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 will have up to four service options that will fix electric energy rates and transition charges for a period that generally ranges from four to six years.
- Electric delivery service rates will be frozen for a four-year period for commercial and industrial customers. The generation and transmission components of rates will be frozen for different time periods depending on the service options selected by those customers.
- BGE will be allowed to recover $528 million after-tax of its potentially stranded investments and utility restructuring costs through a competitive transition charge on customers' bills. Residential customers will pay this charge for six years. Commercial and industrial customers will pay in a lump sum or over the four to six-year period, depending on the service option selected by each customer.
- Generation-related regulatory assets and nuclear decommissioning costs will be included in delivery service rates effective July 1, 2000 and will be recovered on a basis approximating their existing amortization schedules.
- Starting July 1, 2000, BGE will unbundle rates to show separate components for delivery service, transition charges, standard offer service (generation), transmission, universal service, and taxes.
- On July 1, 2000, BGE will transfer, 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 will reduce its generation assets, as discussed in Note 4 on page 59, by $150 million pre-tax during the period July 1, 1999 – June 30, 2000 to mitigate a portion of its potentially stranded investments.
- Universal service will be provided for low-income customers without increasing their bills. BGE will provide its share of a statewide fund totaling $34 million annually.

We believe that the Restructuring Order provided sufficient details of the transition plan to competition for BGE's electric generation business to require BGE to discontinue the application of Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulation* for that portion of its business. Accordingly, in the fourth quarter of 1999, we adopted the provisions of SFAS No. 101, *Regulated Enterprises—Accounting for the Discontinuation of FASB Statement No. 71* and Emerging Issues Task Force Consensus (EITF) No. 97-4, *Deregulation of the Pricing of Electricity—Issues Related to the Application of FASB Statements No. 71 and 101* for BGE's electric generation business. BGE's transmission and distribution business continues to meet the requirements of SFAS No. 71 as that business remains regulated. We describe the effect of applying these accounting requirements in Note 4 on page 59.

In early December, the Mid-Atlantic Power Supply Association (MAPSA), Trigen-Baltimore Energy Corporation, and Sweetheart Cup Company, Inc. filed appeals of the Restructuring Order. MAPSA also filed a motion seeking to delay the implementation of the Restructuring Order pending a decision on the merits by the court. While we believe that the appeals are without merit, no assurances can be given as to the timing or outcome of these cases, and whether the outcome will have a material adverse effect on our and BGE's financial results.

**Regulation by the Maryland PSC**

Under traditional rate regulation that will continue for all BGE's businesses except electric generation beginning July 1, 2000, the Maryland PSC determines the rate we can charge our customers. Our rates consist of a "base rate," a "conservation surcharge," and a "fuel rate."

*Base Rate*

The base rate is the rate the Maryland PSC allows us to charge our customers for the cost of providing them service, plus a profit. We have 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.

Except as provided under the terms of the electric Restructuring Order discussed on page 24, BGE may ask the Maryland PSC to increase base rates from time to time. The Maryland PSC historically has allowed BGE to increase base rates to recover increased utility plant asset costs, plus a profit, beginning at the time of replacement. Generally, rate increases improve our utility earnings because they allow us to collect more revenue. However, rate increases are normally granted based on historical data and those increases may not always keep pace with increasing costs. Other parties may petition the Maryland PSC to decrease base rates.

On November 17, 1999, BGE filed an application with the Maryland PSC to increase its gas base rates. We discuss this filing in the gas "Base Rates" section on page 29.

*Conservation Surcharge*

The Maryland PSC allows us to include in electric and gas rates a component to recover money spent on conservation programs. This component is called a "conservation surcharge." However, under this surcharge the Maryland PSC limits what our profit can be. If at the end of the year we have exceeded our allowed profit, we defer (include as a liability on our Consolidated Balance Sheets and exclude from our Consolidated Statements of Income) the excess in that year and we lower the amount of future surcharges to our customers to correct the amount of overage, plus interest. As a result of the Restructuring Order, the electric conservation surcharge was frozen at its current level and the associated profit limitation is no longer applicable.

*Fuel Rate*

Currently, we charge our electric customers separately for the fuel we use to generate electricity (nuclear fuel, coal, gas, or oil) and for the net cost of purchases and sales of electricity. We charge the actual cost of these items to the customer with no profit to us. If these costs go up, the Maryland PSC permits us to increase the fuel rate. If these costs go down, our customers benefit from a reduction in the fuel rate. The fuel rate is mostly impacted by the amount of electricity generated at Calvert Cliffs because the cost of nuclear fuel is cheaper than coal, gas, or oil.

Under the Restructuring Order, BGE's electric fuel rate is frozen at its current level until July 1, 2000, at which time the fuel rate clause will be discontinued. We will continue to defer the difference between our actual costs of fuel and energy and what we collect from customers under the fuel rate through June 30, 2000. After that date, earnings will be affected by the changes in the cost of fuel and energy. We discuss our exposure to market risk further in the "Current Issues" section on page 21. In addition, any accumulated difference between our actual costs of fuel and energy and the amounts collected from customers under the electric fuel rate clause will be collected from our customers over a period to be determined by the Maryland PSC. At December 31, 1999, the amount to be collected from customers was $60.0 million.

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 29 and in Note 1 on page 51.

**Weather**

Weather affects the demand for electricity and gas. Very hot summers and very cold winters increase demand. Mild weather reduces demand. Weather impacts residential sales more than commercial and industrial sales, which are mostly affected by business needs for electricity and gas.

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

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

Effective March 1, 1998, the Maryland PSC allowed us to implement a monthly adjustment to our gas business revenues to eliminate the effect of abnormal weather patterns. We discuss this further in the "Weather Normalization" section on page 29.

We show the number of cooling and heating degree days in 1999 and 1998, 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.

| | 1999 | 1998 | 30-year average |
|---|---|---|---|
| Cooling degree days | **845** | 915 | 843 |
| Percentage change from prior year | **(7.7)%** | 22.7% | |
| Heating degree days | **4,585** | 4,119 | 4,755 |
| Percentage change from prior year | **11.3%** | (14.6)% | |

### Other Factors

Other factors, aside from weather, impact the demand for electricity and gas. These factors include the "number of customers" and "usage per customer" during a given period. We use these terms later in our discussions of electric and gas operations. In those sections, we discuss how these and other factors affected electric and gas sales during 1999 and 1998.

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. When customer choice for electric generation begins on July 1, 2000, a portion of BGE's electric customers will become delivery service customers only and will purchase their electricity from other sources. Other electric customers will receive standard offer service from BGE at the fixed rates provided by the Restructuring Order. To the extent our electricity generation exceeds or is less than the electricity demanded by customers utilizing our standard offer service, the incremental electricity will be sold or purchased in the wholesale market at prevailing market prices. We discuss our exposure to market risk further in the "Current Issues" section on page 21.

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.

## Utility Business Earnings Per Share of Common Stock

| | 1999 | 1998 | 1997 |
|---|---|---|---|
| Electric business | **$1.81** | $1.75 | $1.77 |
| Gas business | **.22** | .18 | .17 |
| Total utility earnings per share before nonrecurring charge included in operations | **2.03** | 1.93 | 1.94 |
| Nonrecurring charge included in operations: | | | |
| Hurricane Floyd (see Note 2 on page 55) | **(.03)** | – | – |
| Write-off of merger costs (see Note 2 on page 55) | **–** | – | (.25) |
| Total utility earnings per share before extraordinary item | **2.00** | 1.93 | 1.69 |
| Extraordinary loss (see Note 4 on page 59) | **(.44)** | – | – |
| Total utility earnings per share | **$1.56** | $1.93 | $1.69 |

Our 1999 total utility earnings decreased $53.9 million, or $.37 per share, compared to 1998. Our 1998 total utility earnings increased $36.1 million, or $.24 per share, compared to 1997. We discuss the factors affecting utility earnings below.

### Electric Operations

The discussion below reflects the operations of the electric generation portion of our utility business under current rate regulation by the Maryland PSC. Our electric business will change significantly beginning July 1, 2000 as we enter into retail customer choice for electric generation. Also, no earlier than July 1, 2000, and upon receipt of all regulatory approvals, all of BGE's generation assets will be transferred, at book value, to nonregulated subsidiaries of Constellation Energy. These assets represent about 6,240 megawatts of generation capacity with a total projected net book value at June 30, 2000 of approximately $2.4 billion.

We estimate that the electric generation portion of our business currently represents about one-half of BGE's operating income.

We expect BGE to transfer approximately $278 million of tax exempt debt to our nonregulated subsidiaries related to the transferred assets and that BGE will receive approximately $1.1 billion in unsecured promissory notes. Repayments of the notes by our nonregulated subsidiaries will be used exclusively to service certain long-term debt of BGE. BGE will also transfer equity associated with the generating assets to nonregulated subsidiaries of Constellation Energy.

Given the uncertainties surrounding electric deregulation as discussed in the "Strategy" and "Current Issues" sections on page 21, the results discussed in this section may not be indicative of the future performance of our generation business. Also, these results will not be indicative of the future performance of BGE once BGE transfers all of its generation assets to nonregulated subsidiaries of Constellation Energy. The impact of this transfer on BGE's financial results will be material. The total assets, liabilities, and common shareholders' equity of Constellation Energy will not change as a result of the transfer.

**Electric Revenues**

The changes in electric revenues in 1999 and 1998 compared to the respective prior year were caused by:

| | 1999 | 1998 |
|---|---|---|
| | *(In millions)* | |
| Electric system sales volumes | **$41.2** | $50.8 |
| Base rates | **0.8** | (6.6) |
| Fuel rates | **3.7** | (8.1) |
| Total change in electric revenues from electric system sales | **45.7** | 36.1 |
| Interchange and other sales | **(8.2)** | (13.2) |
| Other | **2.1** | 4.6 |
| Total change in electric revenues | **$39.6** | $27.5 |

*Electric System Sales Volumes*

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

The percentage changes in our electric system sales volumes, by type of customer, in 1999 and 1998 compared to the respective prior year were:

| | 1999 | 1998 |
|---|---|---|
| Residential | **3.5%** | 1.5% |
| Commercial | **2.6** | 3.9 |
| Industrial | **(5.1)** | 0.2 |

In 1999, we sold more electricity to residential customers due to higher usage per customer, colder winter weather, and an increased number of customers. This increase was partially offset by milder spring and early summer weather. We sold more electricity to commercial customers mostly due to higher usage per customer, an increased number of customers, and colder winter weather. We sold less electricity to industrial customers mostly because usage by Bethlehem Steel and other industrial customers decreased. Usage decreased at Bethlehem Steel as a result of a shut-down from June to August for an upgrade to their facilities that temporarily reduced their electricity consumption. This decrease was partially offset by an increase in the number of industrial customers.

In 1998, we sold more electricity to residential customers mostly because of an increased number of customers, hotter summer weather, and higher usage per customer. The increase in sales to residential customers was partially offset by milder winter weather. We sold more electricity to commercial customers mostly because of higher usage per customer. We sold about the same amount of electricity to industrial customers as we did in 1997.

*Base Rates*

In 1999, base rate revenues were about the same compared to 1998.

In 1998, base rate revenues decreased compared to 1997. Although we sold more electricity in 1998, our base rate revenues decreased because of lower conservation surcharge revenues.

*Fuel Rates*

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

In 1998, fuel rate revenues decreased compared to 1997. Although we sold more electricity, the fuel rate was lower mostly because we were able to use a less-costly mix of generating plants and electricity purchases.

*Interchange and Other Sales*

"Interchange and other sales" are sales in the PJM (Pennsylvania-New Jersey-Maryland) Interconnection energy market and to others. The PJM is a regional power pool with members that include many wholesale market participants, as well as BGE and other utility companies. We sell energy to PJM members and to others after we have satisfied the demand for electricity in our own system.

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

**Electric Fuel and Purchased Energy Expenses**

| | 1999 | 1998 | 1997 |
|---|---|---|---|
| | | *(In millions)* | |
| Actual costs | **$538.0** | $514.7 | $504.5 |
| Net (deferral) recovery of costs under electric fuel rate clause (see Note 1 on page 50) | **(70.3)** | (9.0) | 15.2 |
| Total electric fuel and purchased energy expenses | **$467.7** | $505.7 | $519.7 |

*Actual Costs*

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

In 1998, our actual costs increased compared to 1997 mostly because we settled a capacity contract with PECO.

*Electric Fuel Rate Clause*

Under the electric fuel rate clause, we defer (include as an asset or liability in our Consolidated Balance Sheets and exclude from our Consolidated Statements of Income) the difference between our actual costs of fuel and energy and what we collect from customers under the fuel rate in a given period. We either bill or refund our customers that difference in the future. We discuss the calculation of the fuel rate and its future discontinuance in Note 1 on page 50.

In 1999 and 1998, our actual costs of fuel and energy were higher than the fuel rate revenues we collected from our customers. The increase in the 1999 deferral reflects higher purchased power costs, especially during record-setting summer peak loads.

**Electric Operations and Maintenance Expenses**

In 1999, electric operations and maintenance expenses were about the same compared to 1998. In 1999, operations and maintenance expenses include the costs for system restoration activities related to Hurricane Floyd of $7.5 million and a major winter ice storm. This was offset by lower employee benefit costs in 1999 and a 1998 $6.0 million write-off of contributions to a third party for a low-level radiation waste facility that was never completed.

In 1998, electric operations and maintenance expenses increased $28.7 million compared to 1997 mostly because of:

- higher nuclear costs,
- higher employee benefit costs, and
- the $6.0 million write-off for the low-level radiation waste facility discussed above.

**Electric Depreciation and Amortization Expense**

In 1999, electric depreciation and amortization expense increased $63.4 million compared to 1998 mostly because of the $75.0 million amortization of the regulatory asset for the reduction in generation plant provided for in the Restructuring Order. This increase was partially offset by lower amortization of deferred electric conservation expenditures due to the write-off of a portion of these expenditures that will not be recovered under the Restructuring Order. We discuss the accounting implications of the Restructuring Order further in Note 4 on page 59.

In 1998, electric depreciation and amortization expense increased $26.5 million compared to 1997 mostly because:

- in October 1998, the Maryland PSC authorized us to implement new electric depreciation rates retroactive to January 1, 1998, which increased depreciation expense by approximately $13.9 million,
- we had more electric plant in service (as our level of plant in service changes, the amount of our depreciation and amortization expense changes), and
- we reduced the amortization period for certain computer software beginning in the first quarter of 1998 from five years to three years.

## Gas Operations

All BGE industrial and commercial gas customers, and effective November 1, 1999, all BGE residential customers have the option to purchase gas from other suppliers. We do not expect the impact of customer choice to have a material effect on our, and BGE's, financial results.

### Gas Revenues

The changes in gas revenues in 1999 and 1998 compared to the respective prior year were caused by:

| | 1999 | 1998 |
|---|---|---|
| | *(In millions)* | |
| Gas system sales volumes | **$ 8.0** | $(10.8) |
| Base rates | **2.2** | 14.2 |
| Weather normalization | **4.5** | 10.1 |
| Gas cost adjustments | **19.8** | (87.6) |
| Total change in gas revenues from gas system sales | **34.5** | (74.1) |
| Off-system sales | **(7.9)** | 1.8 |
| Other | **0.5** | 0.1 |
| Total change in gas revenues | **$27.1** | $(72.2) |

#### *Gas System Sales Volumes*

The percentage changes in our gas system sales volumes, by type of customer, in 1999 and 1998 compared to the respective prior year were:

| | 1999 | 1998 |
|---|---|---|
| Residential | **9.2%** | (11.6)% |
| Commercial | **12.7** | (9.5) |
| Industrial | **(4.8)** | (11.3) |

In 1999, we sold more gas to residential customers mostly for two reasons: colder winter weather and an increased number of customers. This was partially offset by lower usage per customer. We sold more gas to commercial customers mostly because of higher usage per customer, colder winter weather, and an increased number of customers. We sold less gas to industrial customers mostly because of lower usage by Bethlehem Steel and other industrial customers. Usage by Bethlehem Steel decreased due to a shut-down from June to August for an upgrade to their facilities.

In 1998, we sold less gas to residential and commercial customers mostly for two reasons: milder weather and lower usage per customer. This was partially offset by the increase in the number of customers. We sold less gas to industrial customers mostly because of lower usage by Bethlehem Steel and other industrial customers.

#### *Base Rates*

In 1999, base rate revenues increased compared to 1998 mostly due to the increase in our base rates effective March 1, 1998 as discussed below.

In 1998, base rate revenues increased compared to 1997. Although we sold less gas during 1998, our base rate revenues increased mostly because the Maryland PSC authorized an increase in our base rates effective March 1, 1998. The change in rates increased our base rate revenues over the twelve-month period from March 1998 through February 1999 by approximately $16 million.

On November 17, 1999, we applied for a $36.3 million annual increase in our gas base rates. The Maryland PSC is currently reviewing our application and is expected to issue an order by June 2000.

#### *Weather Normalization*

Effective March 1, 1998, the Maryland PSC allowed us to implement 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 will be based on weather that is considered "normal" for the month and, therefore, will not be 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. These clauses operate similarly to the electric fuel rate clause described in the "Electric Fuel Rate Clause" section on page 28. However, under market based rates, our actual cost of gas is compared to a market index (a measure of the market price of gas in a given period). The difference between our actual cost and the market index is shared equally between shareholders and customers, and does not significantly impact earnings. We also discuss this in Note 1 on page 51.

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

In 1999, gas cost adjustment revenues increased compared to the same period of 1998 mostly because we sold more gas at a higher price.

In 1998, gas cost adjustment revenues decreased compared to 1997 mostly because we sold less gas.

*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). Changes in off-system sales do not significantly impact earnings.

In 1999, revenues from off-system gas sales decreased compared to 1998 mostly because we sold less gas off-system.

In 1998, revenues from off-system gas sales increased compared to 1997 mostly because we sold more gas off-system.

### Gas Purchased For Resale Expenses

| | 1999 | 1998 | 1997 |
|---|---|---|---|
| | *(In millions)* | | |
| Actual costs | **$221.8** | $212.2 | $291.6 |
| Net recovery (deferral) of costs under gas adjustment clauses (see Note 1 on page 51) | **8.8** | (3.6) | 0.5 |
| Total gas purchased for resale expenses | **$230.6** | $208.6 | $292.1 |

*Actual Costs*

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

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

In 1998, actual gas costs decreased compared to 1997 mostly because we sold less gas.

*Gas Adjustment Clauses*

We charge customers for the cost of gas sold through gas adjustment clauses (determined by the Maryland PSC), as discussed under "Gas Cost Adjustments" earlier in this section.

In 1999, actual gas costs were lower than the fuel rate revenues we collected from our customers.

In 1998, actual gas costs were higher than the fuel rate revenues we collected from our customers.

### Gas Operations and Maintenance Expenses

In 1999, gas operations and maintenance expenses were about the same compared to 1998.

In 1998, gas operations and maintenance expenses increased $3.9 million compared to 1997 mostly because of higher employee benefit costs.

### Gas Depreciation and Amortization Expense

In 1999, gas depreciation and amortization expense was about the same compared to 1998.

In 1998, gas depreciation and amortization expense increased $6.1 million compared to 1997 mostly because:

- we had more gas plant in service, and
- we reduced the amortization period for certain computer software beginning in the first quarter of 1998 from five years to three years.

## Diversified Businesses

Our diversified businesses engage primarily in energy services. We list each of our diversified businesses in the "Introduction" section on page 20. We describe our diversified businesses in more detail in our most recent Annual Report on Form 10-K under "Item 1. Business – Diversified Businesses."

**Diversified Business Earnings Per Share of Common Stock**

| | 1999 | 1998 | 1997 |
|---|---|---|---|
| Energy services | | | |
| Power marketing | **$ .23** | $ .05 | $ – |
| Power projects | **.26** | .30 | .25 |
| Other | **(.05)** | (.01) | (.05) |
| Total energy services earnings per share before nonrecurring charges included in operations | **.44** | .34 | .20 |
| Other diversified businesses earnings (losses) per share before nonrecurring charges included in operations | **.01** | (.07) | .14 |
| Total diversified business earnings per share before nonrecurring charges included in operations | **.45** | .27 | .34 |
| Nonrecurring charges included in operations: | | | |
| Write-downs of power projects (see Note 3 on page 56) | **(.12)** | – | – |
| Write-off of energy services investment (see Note 2 on page 55) | **–** | (.04) | – |
| Write-down of financial investment (see Note 3 on page 57) | **(.11)** | – | – |
| Write-downs of real estate and senior-living investments (see Note 2 on page 55 and Note 3 on page 56) | **(.04)** | (.10) | (.31) |
| Total earnings per share | **$ .18** | $ .13 | $ .03 |

Our 1999 diversified business earnings increased $8.1 million, or $.05 per share, compared to 1998. Our 1998 diversified business earnings increased $15.7 million, or $.10 per share, compared to 1997.

We discuss factors affecting the earnings of our diversified businesses below.

## Energy Services

### Power Marketing

In 1999, earnings from our power marketing business increased compared to 1998 because of increased transaction margins and volume.

In 1998, earnings from our power marketing business increased compared to 1997 because of increased power marketing activities in 1998, which was Constellation Power Source's first full year of operations.

Constellation Power Source uses the mark-to-market method of accounting. We discuss the mark-to-market method of accounting and Constellation Power Source's activities in Note 1 on page 51.

As a result of the nature of its business activities, Constellation Power Source's revenue and earnings will fluctuate. We cannot predict these fluctuations, but the effect on our revenues and earnings could be material. The primary factors that cause these fluctuations are:

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

Constellation Power Source's management uses its best estimates to determine the fair value of commodity and derivative positions it holds and sells. These estimates consider various factors including closing exchange and over-the-counter price quotations, time value, volatility factors, and credit exposure. However, it is possible that future market prices could vary from those used in recording assets and liabilities from power marketing and trading activities, and such variations could be material. In 1999, assets and liabilities from energy trading activities (as shown in our Consolidated Balance Sheets beginning on page 42) increased because of greater business activity during the period.

In March 1998, we formed Orion Power Holdings, Inc. (Orion) with Goldman, Sachs Capital Partners II L.P., an affiliate of Goldman, Sachs & Co., to acquire electric generating plants in the United States and Canada. Our energy services businesses own a minority interest in Orion. To date, our energy services businesses have funded $104 million in equity and have a commitment to contribute an additional $121 million to Orion.

**Power Projects**

In 1999, earnings from our power projects business decreased compared to 1998 mostly because of three factors:

- In 1999, our power projects business recorded a $14.2 million after-tax, or $.09 per share, write-off of two geothermal power projects. These write-offs occurred because the expected future cash flows from the projects are less than the investment in the projects. For the first project, this resulted from the inability to restructure certain project agreements. For the second project, we experienced a declining water temperature of the geothermal resource used by one of the plants for production.
- In 1999, our power projects business recorded a $4.5 million after-tax, or $.03 per share, write-down to reflect the fair value of our investment in a power project as a result of our international exit strategy discussed on page 33.
- In 1998, our power projects business recorded a $10.4 million after-tax, or $.07 per share, gain for its share of earnings in a partnership. The partnership recognized a gain on the sale of its ownership interest in a power purchase agreement.

In 1998, earnings from our power projects business increased compared to 1997 mostly because Constellation Power recorded a $10.4 million after-tax gain for its share of earnings in a partnership as discussed above.

***California Power Purchase Agreements***

Constellation Power and subsidiaries and Constellation Investments have $301.8 million invested in 14 projects that sell electricity in California under power purchase agreements called "Interim Standard Offer No. 4" agreements. In 1999, earnings from these projects, excluding any write-offs, were $34.4 million, or $.23 per share, compared to $41.3 million, or $.28 per share in 1998.

Under these agreements, the electricity rates change from fixed rates to variable rates beginning in 1996 and continuing through 2000. The projects which already have had rate changes have lower revenues under variable rates than they did under fixed rates. When the remaining projects transition to variable rates, we expect their revenues also to be lower than they are under fixed rates.

As of December 31, 1999, ten projects had already transitioned to variable rates. The remaining four projects will transition between February and December 2000. The projects which transitioned in 1999 contributed $6.2 million, or $.04 per share to 1999 earnings. Those changing over in 2000 contributed $28.0 million, or $.19 per share to 1999 earnings. We expect earnings from the projects changing over in 2000 to contribute $17.4 million, or $.12 per share to 2000 earnings.

Our power projects business continues to pursue alternatives for some of these projects including:

- repowering the projects to reduce operating costs,
- changing fuels to reduce operating costs,
- renegotiating the power purchase agreements to improve the terms,
- restructuring financing to improve existing terms, and
- selling its ownership interests in the projects.

We evaluate the carrying amount of our investment in these projects for impairment using the methodology discussed in Note 1 on page 52. Constellation Power's management uses its best estimates to determine if there has been an impairment of these investments and considers various factors including forward price curves for energy, fuel costs, and operating costs. However, it is possible that future estimates of market prices and project costs could vary from those used in evaluating these assets, and the impact of such variations could be material.

We also describe these projects and the transition process in Note 10 on page 71.

***International Projects***

At December 31, 1999, Constellation Power had invested about $254.1 million in 10 power projects in Latin America compared to $269.7 million invested in Latin America in 1998. These investments include:

- the purchase of a 51% interest in a Panamanian electric distribution company for approximately $90 million in 1998 by an investment group in which subsidiaries of Constellation Power hold an 80% interest, and
- approximately $98 million for the purchase of existing electric generation facilities and the construction of an electric generation facility in Guatemala.

In December 1999, we decided to exit the international portion of our power projects business as part of our strategy to improve our competitive position. As a result, we recorded a $4.5 million after-tax write-down of our investment in a generating company in Bolivia to reflect the current fair value of this investment. We expect to complete our exit strategy by the end of 2000. We discuss our strategy further in the "Strategy" section on page 21.

### Other Energy Services

In 1999, earnings from our other energy services businesses decreased compared to 1998 mostly because of lower gross margins at our energy products and services business.

In 1998, earnings from our other energy services businesses increased compared to 1997 due to improved results from our energy products and services business. Earnings would have been higher except we recorded a $5.5 million after-tax, or $.04 per share, write-off of our investment in, and certain of our product inventory from, an automated electric distribution equipment company. We recorded this write-off because of that company's inability to raise capital and sell its products.

## Other Diversified Businesses

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

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

This increase was partially offset by a $5.8 million after-tax, or $.04 per share, write-down of certain senior-living facilities related to the proposed sale of these facilities in 1999 as discussed below.

In 1999, our senior-living facilities business 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 12 of our existing senior-living facilities, three facilities under construction, and several sites under development for $72.2 million in cash and $16.0 million in debt assumption. We could not reach an agreement on financing issues that subsequently arose, and the agreement was terminated in November 1999. As a result, our senior-living facilities business engaged a third-party management company to manage its senior-living facilities portfolio including the three facilities now under construction, scheduled to be completed in the first half of 2000.

In 1999, Constellation Real Estate Group, Inc. (CREG) sold Church Street Station, for $11.5 million, the approximate book value of the complex.

In 1999, our financial investments business announced that it would exchange its shares of common stock in Capital Re, an insurance company, for common stock of ACE Limited (ACE), another insurance company, as part of a business combination whereby ACE would acquire all of the outstanding capital stock of Capital Re. Through September 30, 1999, our financial investments business wrote down its $94.2 million investment in Capital Re stock by $20.9 million after-tax, or $.14 per share, to reflect the market value of this investment. The agreement between ACE and Capital Re was subsequently revised on a more favorable basis for Capital Re to include both cash and ACE stock. In December 1999, the transaction was finalized and our financial investments business recorded a $4.9 million after-tax, or $.03 per share, gain on this investment to reflect the closing price of the business combination. This net write-down of Capital Re was partially offset by better market performance of other financial investments in 1999 compared to 1998.

In 1998, earnings from our other diversified businesses decreased compared to 1997 mostly due to lower earnings from our real estate and senior-living facilities and financial investments businesses. Earnings from our real estate and senior-living facilities business decreased mostly due to:

- a $15.4 million after-tax write-down of its investment in Church Street Station,
- lower earnings from various real estate and senior-living facilities projects, and
- a $4.0 million after-tax gain on the sale of two senior-living facilities projects reflected in 1997 results.

In addition, in 1998, our real estate and senior-living facilities business exchanged certain assets and liabilities in return for a 41.9% equity interest in COPT, a real estate investment trust.

In 1998, earnings from our financial investments business decreased compared to 1997 mostly because of:

- better market performance for its investments in 1997, and
- a $6.0 million after-tax gain on the sale of stock held by a financial limited partnership reflected in 1997 results.

We discuss our real estate projects, the write-downs of our real estate projects, the COPT transaction, and our financial investments further in Note 3 beginning on page 56.

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

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

Cash flow from real estate operations has not been enough to make the monthly loan payments on some of these projects. Cash shortfalls have been covered by cash obtained from the cash flows of other diversified subsidiaries.

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

Our current real estate strategy is to hold each real estate project until we can realize a reasonable value for it. We evaluate strategies for all our businesses, including real estate, on an ongoing basis. We anticipate that competing demands for our financial resources and changes in the utility industry will cause us to evaluate thoroughly all business strategies on a regular basis so we use capital and other resources in a manner that is most beneficial.

Under accounting rules, we are required to write down the value of a real estate project to market value in either of two cases. The first is if we change our intent about a project from an intent to hold to an intent to sell and the market value of that project is below book value. The second is if the expected future cash flow from the project is less than the investment in the project.

## Consolidated Nonoperating Income and Expenses

### Other Income and Expenses

In September 1995, we signed an agreement to merge with Potomac Electric Power Company after all necessary regulatory approvals were received. In December 1997, both companies mutually terminated the merger agreement. Accordingly, in 1997, we wrote off $57.9 million of costs related to the merger. This write-off reduced after-tax earnings by $37.5 million, or $.25 per share.

### Fixed Charges

In 1999, fixed charges decreased $7.7 million compared to 1998 mostly because we had less BGE preference stock outstanding.

In 1998, fixed charges increased $4.0 million compared to 1997 mostly because we had more debt outstanding. Our fixed charges would have been higher except we had less BGE preference stock outstanding and lower interest rates in 1998 compared to 1997.

### Income Taxes

In 1999, income taxes increased $8.2 million compared to 1998 because we had higher taxable income from both our utility operations and our diversified businesses.

In 1998, income taxes increased $20.2 million compared to 1997 because we had higher taxable income from both our utility operations and our diversified businesses.

Please refer to Note 4 on page 58 for a discussion of tax law changes. These changes are designed, in part, to tax Maryland electric generating facilities on a more comparable basis with electric generation in other states.

## Financial Condition

*Cash Flows*

| | **1999** | 1998 | 1997 |
|---|---|---|---|
| | | *(In millions)* | |
| Cash provided by (used in): | | | |
| Operating Activities | **$679.0** | $799.8 | $696.3 |
| Investing Activities | **(615.1)** | (711.3) | (520.8) |
| Financing Activities | **(144.9)** | (77.4) | (79.6) |

In 1999 and 1998, cash provided by operations changed compared to the respective prior year mostly because of changes in working capital requirements.

In 1999, we used less cash for investing activities compared to 1998 mostly due to lower investments in international power projects and in the real estate and senior-living facilities business. This was partially offset by:

- our energy services businesses increased the investment in Orion Power Holdings, Inc. by $97.7 million,
- our power projects business increased its investment in domestic power projects, primarily related to the 800 megawatts of peaking capacity as discussed in the "Capital Requirements of our Diversified Businesses" section on page 37, and
- BGE increased its construction expenditures by $46.5 million.

In 1998, net cash used in investing activities increased compared to 1997 mostly because of the additional investments in international power projects. This was partially offset by a $33.8 million decrease in utility construction expenditures.

Total utility construction expenditures, including the allowance for funds used during construction, were $385.9 million in 1999 as compared to $339.4 million in 1998 and $373.2 million in 1997.

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

In 1998, cash used in financing activities was about the same compared to 1997. In 1998, we issued more long-term debt and common stock, and had contributions from minority interests of approximately $86 million related to the acquisition of a distribution company in Panama. This was offset by the repayment of short-term borrowings that matured, sinking fund requirements, and early redemption of higher cost securities.

***Security Ratings***

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

| | Standard & Poors Rating Group | Moody's Investors Service | Duff & Phelps' Credit Rating Co. |
|---|---|---|---|
| *Constellation Energy* | | | |
| Unsecured Debt | A- | A3 | A |
| *BGE* | | | |
| Mortgage Bonds | AA- | A1 | AA- |
| Unsecured Debt | A | A2 | A+ |
| Trust Originated Preferred Securities and Preference Stock | A- | "a2" | A |

## Capital Resources

Our business requires a great deal of capital. Our actual consolidated capital requirements for the years 1997 through 1999, along with estimated annual amounts for the years 2000 through 2002, are shown in the table below. For the year ended December 31, 1999, the ratio of earnings to fixed charges for Constellation Energy was 2.87.

Investment requirements for 2000 through 2002 include estimates of funding for existing and anticipated projects. We continuously review and modify those estimates. Actual investment requirements may vary from the estimates included in the table below because of a number of factors including:

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

Our estimates are also subject to additional factors. Please see the "Forward Looking Statements" section on page 39.

No earlier than July 1, 2000, and upon receipt of all regulatory approvals, all of BGE's generation assets will be transferred to nonregulated subsidiaries of Constellation Energy. The discussion and table for capital requirements below include these generation assets as part of the utility business.

| | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 |
|---|---|---|---|---|---|---|
| | | | *(In millions)* | | | |
| **Utility Business Capital Requirements:** | | | | | | |
| Construction expenditures (excluding AFC) | | | | | | |
| Electric | $ 238 | $ 239 | $ 283 | $ 329 | $ 332 | $ 312 |
| Gas | 89 | 55 | 59 | 63 | 61 | 61 |
| Common | 38 | 35 | 34 | 25 | 23 | 23 |
| Total construction expenditures | 365 | 329 | 376 | 417 | 416 | 396 |
| AFC | 8 | 10 | 10 | 4 | 4 | 4 |
| Nuclear fuel (uranium purchases and processing charges) | 44 | 50 | 49 | 50 | 48 | 48 |
| Deferred conservation expenditures | 27 | 16 | 1 | — | — | — |
| Retirement of long-term debt and redemption of preference stock | 243 | 222 | 342 | 401 | 281 | 151 |
| Total utility business capital requirements | 687 | 627 | 778 | 872 | 749 | 599 |
| **Diversified Business Capital Requirements:** | | | | | | |
| Investment requirements | 156 | 325 | 278 | 764 | 1,001 | 755 |
| Retirement of long-term debt | 188 | 232 | 189 | 284 | 367 | 2 |
| Total diversified business capital requirements | 344 | 557 | 467 | 1,048 | 1,368 | 757 |
| Total capital requirements | $1,031 | $1,184 | $1,245 | $1,920 | $2,117 | $1,356 |

### Capital Requirements of Our Utility Business

Our estimates of future electric construction expenditures do not include costs to build more generating units to meet load requirements for BGE customers. Electric construction expenditures include improvements to generating plants and to our transmission and distribution facilities, and costs for replacing the steam generators and renewing the operating licenses at Calvert Cliffs. The operating licenses expire in 2014 for Unit 1 and in 2016 for Unit 2. If we do not replace the steam generators, we may not be able to operate the Calvert Cliffs units beyond 2014 and 2016. We expect the steam generator replacements to occur during the 2002 refueling outage for Unit 1 and during the 2003 refueling outage for Unit 2. We discuss the license extension process further in the "Current Issues" section on page 22. We estimate these Calvert Cliffs costs to be:

- $40 million in 2000,
- $66 million in 2001,
- $88 million in 2002, and
- $60 million in 2003.

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

- $63 million in 2000,
- $52 million in 2001, and
- $4 million in 2002.

We discuss the NOx regulations and timing of expenses further in Note 10 on page 69.

Our utility operations provided about 99% in 1999, 108% in 1998, and 105% in 1997 of the cash needed to meet its capital requirements, excluding cash needed to retire debt and redeem preference stock.

During the three years from 2000 through 2002, we expect our existing utility business to provide about 115% of the cash needed to meet the capital requirements for these operations, excluding cash needed to retire debt. The table for capital requirements on page 36 includes the requirements for BGE fossil and nuclear generation under "Utility Business Capital Requirements–Electric" through 2002 even though these assets are to be transferred to nonregulated subsidiaries on or about July 1, 2000.

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.

When BGE cannot meet utility capital requirements internally, BGE sells debt and preference stock. BGE also sells securities when market conditions permit it to refinance existing debt or preference stock at a lower cost. The amount of cash BGE needs and market conditions determine when and how much BGE sells.

Future funding for capital expenditures, the retirement of debt, and payments of interest and dividends is expected from internally generated funds, commercial paper issuances, available capacity under credit facilities, and/or the issuance of long-term debt, trust securities, or preference stock.

At December 31, 1999, the Federal Energy Regulatory Commission has authorized BGE to issue up to $700 million of short-term borrowings, including commercial paper. In addition, BGE maintains $123 million in annual committed bank lines of credit and has $60 million in bank revolving credit agreements to support the commercial paper program as discussed in Note 7 on page 65. In addition, BGE has access to interim lines of credit as required from time to time to support its outstanding commercial paper.

**Capital Requirements of Our Diversified Businesses**

Our energy services businesses will require additional funding for:

- growing its power marketing business,
- developing and acquiring power projects, and
- constructing cooling system projects.

Our energy services businesses' investment requirements include the planned construction of 800 megawatts of peaking capacity in the Mid-Atlantic/Mid-West region by the summer of 2001 and an additional 4,300 megawatts of peaking and combined cycle production facilities scheduled for completion in 2002 and beyond.

Our investment requirements also include our energy services businesses' commitment to contribute up to an additional $121 million in equity to Orion. To date, our energy services businesses have funded $104 million in equity to Orion.

Our energy services businesses have met their capital requirements in the past through borrowing, cash from their operations, and from time to time equity contributions from BGE.

Future funding for the expansion of our energy services businesses is expected from internally generated funds, commercial paper issuances and long-term debt financing by Constellation Energy, and from time to time equity contributions from Constellation Energy. BGE Home Products & Services may also meet capital requirements through sales of receivables.

At December 31, 1999, Constellation Energy has a commercial paper program where it can issue up to $500 million in short-term notes to fund its diversified businesses. To support its commercial paper program, Constellation Energy maintains $35 million in annual committed bank lines of credit and has a $135 million revolving credit agreement, under which it can also issue letters of credit. In addition, Constellation Energy has access to interim lines of credit as required from time to time to support its outstanding commercial paper. ComfortLink has a revolving credit agreement totaling $50 million to provide liquidity for short-term financial needs.

If we can get a reasonable value for our real estate projects, additional cash may be obtained by selling them. Our ability to sell or liquidate assets will depend on market conditions, and we cannot give assurances that these sales or liquidations could be made. We discuss the real estate business and market in the "Other Diversified Businesses" section on page 33.

We discuss our short-term borrowings in Note 7 on page 65 and long-term debt in Note 8 on page 65.

## Market Risk

We are exposed to market risk, including changes in interest rates, certain commodity prices, equity prices, and foreign currency. To manage our market risk, we may enter into various derivative instruments including swaps, forward contracts, futures contracts, and options. Effective July 1, 2000, we will be subject to additional market risk associated with the purchase and sale of energy as discussed in the "Current Issues" section on page 21. In this section, we discuss our current market risk and the related use of derivative instruments.

### Interest Rate Risk

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

**Principal Payments and Interest Rate Detail by Contractual Maturity Date**

| | 2000 | 2001 | 2002 | 2003 | 2004 | Thereafter | Total | Fair value at Dec. 31, 1999 |
|---|---|---|---|---|---|---|---|---|
| | | | | *(In millions)* | | | | |
| **Long-term debt** | | | | | | | | |
| Variable-rate debt | $201.9 | $166.0 | $ 0.9 | $ 7.8 | $ 5.4 | $ 272.8 | $ 654.8 | $ 654.8 |
| Average interest rate | 6.68% | 6.39% | 8.32% | 7.42% | 7.41% | 4.80% | 5.84% | |
| Fixed-rate debt | $484.4 | $482.8 | $154.6 | $289.4 | $154.6 | $1,173.7 | $2,739.5 | $2,637.3 |
| Average interest rate | 7.16% | 7.08% | 7.31% | 6.52% | 5.78% | 6.83% | 6.87% | |

### Commodity Price Risk

We are exposed to the impact of market fluctuations in the price and transportation costs of natural gas, electricity, and other trading commodities. Currently, our gas business and energy services businesses use derivative instruments to manage changes in their respective commodity prices.

#### *Gas Business*

Our 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 51. At December 31, 1999 and 1998, our exposure to commodity price risk for our gas business was not material.

#### *Energy Services Businesses*

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

These factors include:

- seasonal changes in the demand for electricity,
- hourly fluctuations in demand due to weather conditions,
- available generation resources,
- transmission availability and reliability within and between regions, and
- procedures used to maintain the integrity of the physical electricity system during extreme conditions.

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

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

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

The value at risk amount represents the potential loss in the fair value of assets and liabilities from trading activities over a one-day holding period with a 99.6% confidence level. Using this confidence level, Constellation Power Source would expect a one-day change in fair value greater than or equal to the daily value at risk at least once per year. Constellation Power Source's value at risk was $7.2 million as of December 31, 1999 compared to $6.0 million as of December 31, 1998. The average, high, and low value at risk for the year ended December 31, 1999 was $4.8 million, $7.2 million and $1.8 million, respectively.

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

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

We discuss Constellation Power Source's business in the "Power Marketing" section on page 31 and in Note 1 on page 51.

The commodity price risk for our remaining energy services businesses was not material at December 31, 1999 and 1998.

**Equity Price Risk**

We are exposed to price fluctuations in equity markets primarily through our financial investments business and our nuclear decommissioning trust fund. We are required by the NRC to maintain a trust to fund the costs of decommissioning Calvert Cliffs. At December 31, 1999 and 1998, equity price risk was not material. We discuss our nuclear decommissioning trust fund in more detail in Note 1 on page 53. We also describe our financial investments in more detail in Note 3 on page 57.

**Foreign Currency Risk**

We are exposed to foreign currency risk primarily through our power projects business. Our power projects business has $254.1 million invested in 10 international power generation and distribution projects as of December 31, 1999. To manage our exposure to foreign currency risk, the majority of our contracts are denominated in or indexed to the U.S. dollar. At December 31, 1999 and 1998, foreign currency risk was not material. We discuss our international projects in the "Power Projects" section on page 32.

## 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:

- general economic, business, and regulatory conditions,
- energy supply and demand,
- competition,
- federal and state regulations,
- availability, terms, and use of capital,
- nuclear and environmental issues,
- weather,
- implications of the Restructuring Order issued by the Maryland PSC,
- commodity price risk,
- operating our currently regulated generating assets in a deregulated market beginning July 1, 2000 without the benefit of a fuel rate adjustment clause,
- loss of revenues due to customers choosing alternative suppliers,
- higher volatility of earnings and cash flows, and
- increased financial requirements of our nonregulated subsidiaries.

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.

## Report of Management

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 generally accepted accounting principles 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 Chairman of the Board, conducts periodic reviews to maintain the effectiveness of internal control procedures. PricewaterhouseCoopers LLP, independent accountants, audit the financial statements and express their opinion on them. They perform their audit in accordance with generally accepted auditing standards.

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

C.H. Poindexter

David A. Brune

Christian H. Poindexter
*Chairman of the Board*
*and Chief Executive Officer*

David A. Brune
*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 at December 31, 1999 and 1998, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1999 in conformity with accounting principles generally accepted in the United States. 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, 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 the opinion expressed above.

PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Baltimore, Maryland
January 19, 2000

# Consolidated Statements of Income

| Year Ended December 31, | 1999 | 1998 | 1997 |
|---|---|---|---|
| | (In millions, except per share amounts) | | |
| **Revenues** | | | |
| Electric | **$2,258.8** | $2,219.2 | $2,191.7 |
| Gas | **476.5** | 449.4 | 521.6 |
| Diversified businesses | **1,050.9** | 689.5 | 594.3 |
| Total revenues | **3,786.2** | 3,358.1 | 3,307.6 |
| **Operating Expenses** | | | |
| Electric fuel and purchased energy | **467.7** | 505.7 | 519.7 |
| Gas purchased for resale | **230.6** | 208.6 | 292.1 |
| Operations | **546.0** | 554.1 | 518.3 |
| Maintenance | **186.2** | 177.5 | 178.5 |
| Diversified businesses—selling, general, and administrative | **918.7** | 574.6 | 515.7 |
| Depreciation and amortization | **449.8** | 377.1 | 342.9 |
| Taxes other than income taxes | **227.3** | 219.4 | 216.8 |
| Total operating expenses | **3,026.3** | 2,617.0 | 2,584.0 |
| **Income from Operations** | **759.9** | 741.1 | 723.6 |
| **Other Income (Expense)** | | | |
| Write-off of merger costs (see Note 2) | – | – | (57.9) |
| Other | **7.9** | 5.7 | 5.1 |
| Total other income (expense) | **7.9** | 5.7 | (52.8) |
| **Income Before Fixed Charges and Income Taxes** | **767.8** | 746.8 | 670.8 |
| **Fixed Charges** | | | |
| Interest expense (net) | **241.5** | 240.9 | 230.0 |
| BGE preference stock dividends | **13.5** | 21.8 | 28.7 |
| Total fixed charges | **255.0** | 262.7 | 258.7 |
| **Income Before Income Taxes** | **512.8** | 484.1 | 412.1 |
| Income Taxes | **186.4** | 178.2 | 158.0 |
| **Income Before Extraordinary Item** | **326.4** | 305.9 | 254.1 |
| **Extraordinary Loss, Net of Income Taxes of $30.4 (see Note 4)** | **(66.3)** | – | – |
| **Net Income** | **$ 260.1** | $ 305.9 | $ 254.1 |
| **Earnings Applicable to Common Stock** | **$ 260.1** | $ 305.9 | $ 254.1 |
| **Average Shares of Common Stock Outstanding** | **149.6** | 148.5 | 147.7 |
| **Earnings Per Common Share and Earnings Per Common Share —Assuming Dilution Before Extraordinary Item** | **$ 2.18** | $ 2.06 | $ 1.72 |
| **Extraordinary Loss** | **(.44)** | – | – |
| **Earnings Per Common Share and Earnings Per Common Share —Assuming Dilution** | **$ 1.74** | $ 2.06 | $ 1.72 |

# Consolidated Statements of Comprehensive Income

| Year Ended December 31, | 1999 | 1998 | 1997 |
|---|---|---|---|
| | | (In millions) | |
| **Net Income** | **$ 260.1** | $ 305.9 | $ 254.1 |
| Other comprehensive income/(loss), net of taxes | **(6.2)** | 1.2 | (0.8) |
| **Comprehensive Income** | **$ 253.9** | $ 307.1 | $ 253.3 |

*See Notes to Consolidated Financial Statements.*

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

# Consolidated Balance Sheets

| *At December 31,* | 1999 | 1998 |
|---|---|---|
| | *(In millions)* | |
| **Assets** | | |
| **Current Assets** | | |
| Cash and cash equivalents | $ 92.7 | $ 173.7 |
| Accounts receivable (net of allowance for uncollectibles of $34.8 and $35.4 respectively) | 578.5 | 422.7 |
| Trading securities | 136.5 | 119.7 |
| Assets from energy trading activities | 312.1 | 133.0 |
| Fuel stocks | 94.9 | 85.4 |
| Materials and supplies | 149.1 | 145.1 |
| Prepaid taxes other than income taxes | 72.4 | 68.8 |
| Other | 54.0 | 21.4 |
| Total current assets | 1,490.2 | 1,169.8 |
| **Investments and Other Assets** | | |
| Real estate projects and investments | 310.1 | 353.9 |
| Power projects | 785.4 | 743.1 |
| Financial investments | 145.4 | 198.0 |
| Nuclear decommissioning trust fund | 217.9 | 181.4 |
| Net pension asset | 99.5 | 108.0 |
| Other | 422.9 | 243.3 |
| Total investments and other assets | 1,981.2 | 1,827.7 |
| **Utility Plant** | | |
| Plant in service | | |
| Electric | 7,088.6 | 6,890.3 |
| Gas | 962.0 | 921.3 |
| Common | 569.5 | 552.8 |
| Total plant in service | 8,620.1 | 8,364.4 |
| Accumulated depreciation | (3,466.1) | (3,087.5) |
| Net plant in service | 5,154.0 | 5,276.9 |
| Construction work in progress | 222.3 | 223.0 |
| Nuclear fuel (net of amortization) | 133.8 | 132.5 |
| Plant held for future use | 13.0 | 24.3 |
| Net utility plant | 5,523.1 | 5,656.7 |
| **Deferred Charges** | | |
| Regulatory assets (net) | 637.4 | 565.7 |
| Other | 51.9 | 55.1 |
| Total deferred charges | 689.3 | 620.8 |
| **Total Assets** | $9,683.8 | $9,275.0 |

*See Notes to Consolidated Financial Statements.*

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

| *At December 31,* | **1999** | 1998 |
|---|---|---|
| | *(In millions)* | |
| **Liabilities and Capitalization** | | |
| **Current Liabilities** | | |
| Short-term borrowings | **$ 371.5** | $ — |
| Current portions of long-term debt and preference stock | **808.3** | 541.7 |
| Accounts payable | **365.1** | 270.5 |
| Customer deposits | **40.6** | 35.5 |
| Liabilities from energy trading activities | **163.8** | 99.0 |
| Dividends declared | **66.1** | 66.1 |
| Accrued taxes | **19.2** | 6.5 |
| Accrued interest | **55.3** | 58.6 |
| Accrued vacation costs | **35.3** | 34.7 |
| Other | **78.2** | 45.3 |
| Total current liabilities | **2,003.4** | 1,157.9 |
| **Deferred Credits and Other Liabilities** | | |
| Deferred income taxes | **1,288.8** | 1,309.1 |
| Postretirement and postemployment benefits | **269.8** | 217.0 |
| Deferred investment tax credits | **109.6** | 118.0 |
| Decommissioning of federal uranium enrichment facilities | **27.2** | 30.8 |
| Other | **226.6** | 142.6 |
| Total deferred credits and other liabilities | **1,922.0** | 1,817.5 |
| **Capitalization** | | |
| Long-term debt | **2,575.4** | 3,128.1 |
| BGE preference stock not subject to mandatory redemption | **190.0** | 190.0 |
| Common shareholders' equity | **2,993.0** | 2,981.5 |
| Total capitalization | **5,758.4** | 6,299.6 |
| **Commitments, Guarantees, and Contingencies (see Note 10)** | | |
| **Total Liabilities and Capitalization** | **$9,683.8** | $9,275.0 |

*See Notes to Consolidated Financial Statements.*

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

# Consolidated Statements of Cash Flows

| *Year Ended December 31,* | **1999** | 1998 | 1997 |
|---|---|---|---|
| | | *(In millions)* | |
| **Cash Flows From Operating Activities** | | | |
| Net income | **$ 260.1** | $ 305.9 | $ 254.1 |
| Adjustments to reconcile to net cash provided by operating activities | | | |
| Extraordinary loss | **66.3** | – | – |
| Depreciation and amortization | **505.9** | 429.4 | 396.8 |
| Deferred income taxes | **13.0** | 17.5 | 7.4 |
| Investment tax credit adjustments | **(8.6)** | (8.8) | (7.5) |
| Deferred fuel costs | **(61.1)** | (8.3) | 18.3 |
| Accrued pension and postemployment benefits | **36.1** | 41.6 | (18.0) |
| Write-off of merger costs | **–** | – | 57.9 |
| Write-downs of real estate investments | **8.3** | 23.7 | 70.8 |
| Write-down of financial investment | **26.2** | – | – |
| Write-downs of power projects | **28.5** | – | – |
| Equity in earnings of affiliates and joint ventures (net) | **(7.6)** | (54.5) | (42.5) |
| Changes in assets from energy trading activities | **(179.1)** | (123.6) | (9.4) |
| Changes in liabilities from energy trading activities | **64.8** | 90.4 | 8.6 |
| Changes in other current assets | **(216.4)** | 18.3 | (54.7) |
| Changes in other current liabilities | **121.0** | 77.0 | 42.6 |
| Other | **21.6** | (8.8) | (28.1) |
| Net cash provided by operating activities | **679.0** | 799.8 | 696.3 |
| **Cash Flows From Investing Activities** | | | |
| Utility construction and other capital expenditures | **(436.2)** | (406.1) | (443.9) |
| Contributions to nuclear decommissioning trust fund | **(17.6)** | (17.6) | (17.6) |
| Merger costs | **–** | – | (20.9) |
| Purchases of marketable equity securities | **(27.3)** | (33.3) | (23.0) |
| Sales of marketable equity securities | **34.9** | 32.8 | 46.5 |
| Other financial investments | **13.7** | 14.6 | (0.4) |
| Real estate projects and investments | **49.3** | 21.5 | 24.2 |
| Power projects | **(171.1)** | (252.5) | (44.3) |
| Other | **(60.8)** | (70.7) | (41.4) |
| Net cash used in investing activities | **(615.1)** | (711.3) | (520.8) |
| **Cash Flows From Financing Activities** | | | |
| Proceeds from issuance of | | | |
| Short-term borrowings | **2,801.9** | 1,962.2 | 2,719.0 |
| Long-term debt | **302.8** | 831.3 | 622.0 |
| Common stock | **9.6** | 51.8 | – |
| Repayment of short-term borrowings | **(2,430.4)** | (2,278.3) | (2,736.1) |
| Reacquisition of long-term debt | **(584.4)** | (355.2) | (343.3) |
| Redemption of preference stock | **(7.0)** | (127.9) | (104.5) |
| Common stock dividends paid | **(251.1)** | (246.0) | (239.2) |
| Other | **13.7** | 84.7 | 2.5 |
| Net cash used in financing activities | **(144.9)** | (77.4) | (79.6) |
| **Net (Decrease) Increase in Cash and Cash Equivalents** | **(81.0)** | 11.1 | 95.9 |
| **Cash and Cash Equivalents at Beginning of Year** | **173.7** | 162.6 | 66.7 |
| **Cash and Cash Equivalents at End of Year** | **$ 92.7** | $ 173.7 | $ 162.6 |
| **Other Cash Flow Information** | | | |
| Cash paid during the year for: | | | |
| Interest (net of amounts capitalized) | **$ 245.3** | $ 236.7 | $ 224.2 |
| Income taxes | **$ 165.6** | $ 164.3 | $ 171.2 |

**Noncash Investing and Financing Activities:**

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

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

# Consolidated Statements of Common Shareholders' Equity

| *Years Ended December 31, 1999, 1998, and 1997* | Common Stock Shares | Common Stock Amount | Retained Earnings | Accumulated Other Comprehensive (Loss) Income | Total Amount |
|---|---|---|---|---|---|
| | *(Dollar amounts in millions, number of shares in thousands)* | | | | |
| **Balance at December 31, 1996** | 147,667 | $1,429.9 | $1,419.1 | $5.7 | $2,854.7 |
| Net income | | | 254.1 | | 254.1 |
| Common stock dividends declared ($1.63 per share) | | | (240.7) | | (240.7) |
| Other | | 3.1 | | | 3.1 |
| Net unrealized loss on securities | | | | (1.2) | (1.2) |
| Deferred taxes on net unrealized loss on securities | | | | 0.4 | 0.4 |
| **Balance at December 31, 1997** | 147,667 | 1,433.0 | 1,432.5 | 4.9 | 2,870.4 |
| Net income | | | 305.9 | | 305.9 |
| Common stock dividend declared ($1.67 per share) | | | (248.1) | | (248.1) |
| Common stock issued | 1,579 | 51.8 | | | 51.8 |
| Other | | 0.3 | | | 0.3 |
| Net unrealized gain on securities | | | | 1.8 | 1.8 |
| Deferred taxes on net unrealized gain on securities | | | | (0.6) | (0.6) |
| **Balance at December 31, 1998** | 149,246 | 1,485.1 | 1,490.3 | 6.1 | 2,981.5 |
| 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 loss on securities | | | | **(9.6)** | **(9.6)** |
| Deferred taxes on net unrealized loss on securities | | | | **3.4** | **3.4** |
| **Balance at December 31, 1999** | **149,556** | **$1,494.0** | **$1,499.1** | **$(0.1)** | **$2,993.0** |

*See Notes to Consolidated Financial Statements.*

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

# Consolidated Statements of Capitalization

| At December 31, | 1999 | 1998 |
|---|---|---|
| | (In millions) | |
| **Long-Term Debt** | | |
| First Refunding Mortgage Bonds of BGE | | |
| Floating rate series, due April 15, 1999 | **$ –** | $ 125.0 |
| 8.40% Series, due October 15, 1999 | **–** | 91.1 |
| 5½% Series, due July 15, 2000 | **124.3** | 125.0 |
| 8⅜% Series, due August 15, 2001 | **122.3** | 122.3 |
| 7¼% Series, due July 1, 2002 | **124.5** | 124.5 |
| 5½% Installment Series, due July 15, 2002 | **8.5** | 9.1 |
| 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 | **125.0** | 125.0 |
| 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 | **109.9** | 125.0 |
| 7½% Series, due April 15, 2023 | **84.1** | 84.1 |
| Total First Refunding Mortgage Bonds of BGE | **1,321.7** | 1,554.2 |
| Other long-term debt of BGE | | |
| Medium-term notes, Series B | **60.0** | 60.0 |
| Medium-term notes, Series C | **101.0** | 116.0 |
| Medium-term notes, Series D | **128.0** | 215.0 |
| Medium-term notes, Series E | **200.0** | 200.0 |
| Medium-term notes, Series G | **200.0** | 140.0 |
| Medium-term notes, Series H | **177.0** | – |
| 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 |
| Variable rate pollution control loan, due June 1, 2027 | **8.8** | 8.8 |
| Total other long-term debt of BGE | **1,135.8** | 1,000.8 |
| 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 |
| Long-term debt of diversified businesses | | |
| Loans under revolving credit agreements | **33.0** | 74.0 |
| Mortgage and construction loans | | |
| 7.90% mortgage note, due September 12, 2000 | **8.0** | 8.3 |
| 8.00% mortgage note, due July 31, 2001 | **0.1** | 0.1 |
| 8.00% mortgage note, due October 30, 2003 | **1.9** | 1.8 |
| Variable rate mortgage notes and construction loans, due through 2004 | **112.0** | 149.5 |
| 4.25% mortgage note, due March 15, 2009 | **4.6** | 5.1 |
| 9.65% mortgage note, due February 1, 2028 | **9.6** | 9.6 |
| 8.00% mortgage note, due November 1, 2033 | **6.6** | 5.8 |
| Unsecured notes | **511.0** | 616.0 |
| Total long-term debt of diversified businesses | **686.8** | 870.2 |
| Unamortized discount and premium | **(10.6)** | (12.4) |
| Current portion of long-term debt | **(808.3)** | (534.7) |
| Total long-term debt | **$2,575.4** | $3,128.1 |

*continued on page 47*

*See Notes to Consolidated Financial Statements.*

# Consolidated Statements of Capitalization

| *At December 31,* | **1999** | 1998 |
|---|---|---|
| | *(In millions)* | |
| **BGE Preference Stock** | | |
| Cumulative, $100 par value, 6,500,000 shares authorized | | |
| Redeemable preference stock | | |
| 7.85%, 1991 Series | $ – | $ 7.0 |
| Current portion of redeemable preference stock | – | (7.0) |
| Total redeemable preference stock | – | – |
| Preference stock not subject to mandatory redemption | | |
| 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; 149,556,416 and 149,245,641 shares issued and outstanding at December 31, 1999 and 1998, respectively. (At December 31, 1999 166,893 shares were reserved for the Employee Savings Plan and 12,061,756 shares were reserved for the Shareholder Investment Plan.) | **1,494.0** | 1,485.1 |
| Retained earnings | **1,499.1** | 1,490.3 |
| Accumulated other comprehensive (loss) income | **(0.1)** | 6.1 |
| Total common shareholders' equity | **2,993.0** | 2,981.5 |
| **Total Capitalization** | **$5,758.4** | $6,299.6 |

*See Notes to Consolidated Financial Statements.*

# Consolidated Statements of Income Taxes

| *Year Ended December 31,* | **1999** | 1998 | 1997 |
|---|---|---|---|
| | | *(Dollar amounts in millions)* | |
| **Income Taxes** | | | |
| Current | **$182.0** | $169.5 | $158.1 |
| Deferred | | | |
| Change in tax effect of temporary differences | **9.6** | 14.2 | (1.0) |
| Change in income taxes recoverable through future rates | **–** | 3.9 | 8.0 |
| Deferred taxes credited (charged) to shareholders' equity | **3.4** | (0.6) | 0.4 |
| Deferred taxes charged to expense | **13.0** | 17.5 | 7.4 |
| Investment tax credit adjustments | **(8.6)** | (8.8) | (7.5) |
| Income taxes per Consolidated Statements of Income | **$186.4** | $178.2 | $158.0 |
| **Reconciliation of Income Taxes Computed at Statutory Federal Rate to Total Income Taxes** | | | |
| Income before income taxes (excluding BGE preference stock dividends) | **$526.3** | $505.9 | $440.8 |
| Statutory federal income tax rate | **35%** | 35% | 35% |
| Income taxes computed at statutory federal rate | **184.2** | 177.1 | 154.3 |
| Increases (decreases) in income taxes due to | | | |
| Depreciation differences not normalized on regulated activities | **15.3** | 13.6 | 13.9 |
| Allowance for equity funds used during construction | **(2.2)** | (2.2) | (1.9) |
| Amortization of deferred investment tax credits | **(8.6)** | (8.8) | (7.5) |
| Tax credits flowed through to income | **(3.2)** | (0.3) | (0.5) |
| Amortization of deferred tax rate differential on regulated activities | **(3.0)** | (2.3) | (2.3) |
| State income taxes | **8.9** | 9.8 | 6.2 |
| Other | **(5.0)** | (8.7) | (4.2) |
| Total income taxes | **$186.4** | $178.2 | $158.0 |
| Effective federal income tax rate | **35.4%** | 35.2% | 35.8% |

| *At December 31,* | **1999** | 1998 |
|---|---|---|
| | *(Dollar amounts in millions)* | |
| **Deferred Income Taxes** | | |
| Deferred tax liabilities | | |
| Accelerated depreciation | **$ 962.7** | $1,009.9 |
| Allowance for funds used during construction | **202.3** | 204.5 |
| Income taxes recoverable through future rates | **35.7** | 88.4 |
| Deferred termination and postemployment costs | **14.7** | 32.3 |
| Deferred fuel costs | **25.8** | 4.5 |
| Leveraged leases | **19.9** | 22.6 |
| Percentage repair allowance | **35.0** | 36.8 |
| Conservation expenditures | **4.7** | 18.9 |
| Energy trading activities | **71.4** | 33.4 |
| Deferred electric generation-related regulatory assets | **100.3** | – |
| Other | **187.9** | 182.6 |
| Total deferred tax liabilities | **1,660.4** | 1,633.9 |
| Deferred tax assets | | |
| Accrued pension and postemployment benefit costs | **63.6** | 54.3 |
| Deferred investment tax credits | **38.3** | 41.3 |
| Capitalized interest and overhead | **48.3** | 46.6 |
| Contributions in aid of construction | **49.1** | 45.6 |
| Nuclear decommissioning liability | **25.4** | 22.8 |
| Energy trading activities | **15.1** | 20.3 |
| Other | **131.8** | 93.9 |
| Total deferred tax assets | **371.6** | 324.8 |
| Deferred tax liability, net | **$1,288.8** | $1,309.1 |

*See Notes to Consolidated Financial Statements.*

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

## Note 1.

### Significant Accounting Policies

**Nature of Our Business**

On April 30, 1999, Constellation Energy Group, Inc. (Constellation Energy) became the holding company for Baltimore Gas and Electric Company (BGE) and BGE's former subsidiary Constellation Enterprises, Inc. BGE's outstanding common stock automatically became shares of common stock of Constellation Energy. BGE's debt securities, obligated mandatorily redeemable trust preferred securities, and preference stock remain securities of BGE.

Constellation Energy's subsidiaries primarily include BGE and a group of energy services businesses mostly focused on power marketing and merchant generation 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 2 on page 54.

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. Our consolidated financial statements include the accounts of:

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

*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 beginning on page 42, and
- our percentage share of the earnings from the entity in our Consolidated Statements of Income on page 41.

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.

BGE reports its investment in Safe Harbor Water Power Corporation (Safe Harbor) under the equity method. Safe Harbor is a producer of hydroelectric power. BGE owns two-thirds of Safe Harbor's total capital stock, including one-half of the voting stock, and a two-thirds interest in its retained earnings. This investment is included in "Investments and Other Assets – Other" in our Consolidated Balance Sheets on page 42.

*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 generally accepted accounting principles. However, sometimes the Maryland PSC orders an accounting treatment different from that used by nonregulated companies to determine the rates we charge our customers. When this happens, we must defer certain utility expenses and income in our Consolidated Balance Sheets as regulatory assets and liabilities. We have recorded these regulatory assets and liabilities in our Consolidated Balance Sheets in accordance with Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulation*. We summarize and discuss our regulatory assets and liabilities further in Note 5 on page 60.

In 1997, the Financial Accounting Standards Board (FASB) through its Emerging Issues Task Force (EITF) issued EITF 97-4, *Deregulation of the Pricing of Electricity–Issues Related to the Application of FASB Statements No. 71 and 101*. The EITF concluded that a company should cease to apply SFAS No. 71 when either legislation is passed or a regulatory body issues an order that contains sufficient detail to determine how the transition plan will affect the deregulated portion of the business. Additionally, a company would continue to recognize regulatory assets and liabilities in the Consolidated Balance Sheets to the extent that the transition plan provides for their recovery.

On November 10, 1999, the Maryland PSC issued a Restructuring Order that we believe provided sufficient details of the transition plan to competition for BGE's electric generation business to require BGE to discontinue the application of SFAS No. 71 for that portion of its business. Accordingly, in the fourth quarter of 1999, we adopted the provisions of SFAS No. 101, *Regulated Enterprises – Accounting for the Discontinuation of FASB Statement No. 71* and EITF No. 97-4 for BGE's electric generation business. BGE's transmission and distribution business continues to meet the requirements of SFAS No. 71 as that business remains regulated. We discuss this further in Note 4 on page 58.

**Utility Revenues**

We record utility revenues in our Consolidated Statements of Income 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 shown in our Consolidated Statements of Income as "Electric fuel and purchased energy" and "Gas purchased for resale." We discuss each of these separately below.

***Fuel Used to Generate Electricity and Purchases of Electricity From Others***

Until July 1, 2000, we will continue 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 charge 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 charge the actual costs of these items to customers with no profit to us. To do this, we must keep track of what we spend and what we collect from customers under the fuel rate in a given period. Usually these two amounts are not the same because there is a difference between the time we spend the money and the time we collect it from our customers.

Under the electric fuel rate clause, we currently defer (include as an asset or liability in our Consolidated Balance Sheets and exclude from our Consolidated Statements of Income) the difference between our actual costs of fuel and energy and what we collect from customers under the fuel rate in a given period. We either bill or refund our customers that difference in the future. We discuss this and the impact of the Restructuring Order on BGE's electric fuel rate clause further in Note 5 on page 61.

We calculate the electric fuel rate using three factors:

- the mix of generating plants we used over the last 24 months,
- the latest three-month average fuel cost for each generating unit, and
- the net cost of purchases and sales of electricity over the last 24 months.

Historically, we were able to change the fuel rate only if the calculated rate was more than 5% above or below the rate in effect. The fuel rate was affected most by the amount of electricity generated at our Calvert Cliffs Nuclear Power Plant (Calvert Cliffs) because the cost of nuclear fuel is cheaper than coal, gas, or oil. As a result of the Restructuring Order, the fuel rate is frozen at its current level until July 1, 2000, at which time it will be discontinued. We will continue to defer the difference between our actual costs of fuel and energy and what we collect from customers under the fuel rate through June 30, 2000. After that date, earnings will be affected by the changes in the cost of fuel and energy. In addition, any accumulated difference between our actual costs of fuel and energy and the amounts collected from customers under the electric fuel rate clause will be collected from our customers over a period to be determined by the Maryland PSC.

Extended outages at Calvert Cliffs increase fuel costs. Any increase in fuel costs, including extended outages at Calvert Cliffs through June 30, 2000, may result in fuel rate proceedings before the Maryland PSC. In these proceedings, the Maryland PSC would consider whether any portion of the extra fuel costs should be paid by BGE instead of passed on to customers.

We also report two other items as "Electric fuel and purchased energy" in our Consolidated Statements of Income:

- amortization of nuclear fuel (described under "Utility Plant" later in this note). We amortize nuclear fuel based on the energy produced over the life of the fuel. We pay quarterly fees to the Department of Energy for the future disposal of spent nuclear fuel, and accrue these fees based on the kilowatt-hours of electricity sold. We bill our customers for nuclear fuel as described earlier in this note, and
- amortization of deferred costs of decommissioning and decontaminating the Department of Energy's uranium enrichment facilities. We discuss these costs further in Note 5 on page 61.

### *Natural Gas*

We charge our gas customers for the natural gas they purchase from us using "gas cost adjustment clauses" set by the Maryland PSC. These clauses operate similarly to the electric fuel rate clause described earlier in this Note. However, the Maryland PSC approved a modification of the gas cost adjustment clauses to provide a market based rates incentive mechanism. Under market based rates our actual cost of gas is compared to a market index (a measure of the market price of gas in a given period). The difference between our actual cost and the market index is shared equally between shareholders and customers.

## Risk Management

We engage in risk management activities in our gas business and in our diversified businesses. We separately describe these activities for each business below.

### *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 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 activities represent trading activities under EITF 98-10, *Accounting for Contracts Involved in Energy Trading and Risk Management Activities*. Accordingly, we use mark-to-market accounting to record these transactions.

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.

### *Diversified Businesses*

Our subsidiary, Constellation Power Source, engages in power marketing activities, which include trading electricity, other energy commodities, and related derivatives (such as futures, forwards, options, and swaps). Constellation Power Source uses the mark-to-market method of accounting for its trading activities.

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

- commodity positions and derivatives at fair value as "Assets from energy trading activities" or "Liabilities from energy trading activities" in our Consolidated Balance Sheets, and
- changes in fair value as components of "Diversified business revenues" in our Consolidated Statements of Income.

## Taxes

We summarize our income taxes in our Consolidated Statements of Income Taxes on page 48. As you read this section, it may be helpful to refer to those statements.

### *Income Tax Expense*

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

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

Our deferred income tax expense is equal to the changes in the net deferred income tax liability, excluding amounts charged or credited to common shareholders' equity. Our deferred income tax expense is increased or reduced for changes to the "Income taxes recoverable through future rates (net)" regulatory asset (described later in this Note) during the year.

### *Investment Tax Credits*

We have deferred the investment tax credit associated with our regulated utility business 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 diversified businesses, other than leveraged leases.

*Deferred Income Tax Assets and Liabilities*
We must report some of our revenues and expenses differently for our financial statements than we do for income tax purposes. The tax effects of the differences in these items are reported as deferred income tax assets or liabilities in our Consolidated Balance Sheets. We measure the assets and liabilities using income tax rates that are currently in effect.

A portion of our total deferred income tax liability relates to our utility business, but has not been reflected in the rates we charge our customers. We refer to this portion of the liability as "Income taxes recoverable through future rates (net)." We have recorded that portion of the net liability as a regulatory asset in our Consolidated Balance Sheets. We discuss this further in Note 5 on page 60.

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

As discussed in Note 4 on page 58, the tax legislation made comprehensive changes to the state and local taxation of electric and gas utilities.

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

**Real Estate Projects and Investments**
In Note 3 on page 56, we summarize the real estate projects and investments that are in our Consolidated Balance Sheets. The projects and investments consist of:

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

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

**Financial Investments and Trading Securities**
In Note 3 on page 57, we summarize the financial investments that are in our Consolidated Balance Sheets.

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

*Trading Securities*
Our diversified 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 "Diversified business revenues" in our Consolidated Statements of Income.

*Available-for-Sale Securities*
We classify our investments in the nuclear decommissioning trust fund as available-for-sale securities. We include any unrealized gains or losses on the trust assets as a change in the decommissioning reserve. We describe the nuclear decommissioning trust and the reserve under the heading "Decommissioning Costs" later in this note on page 53.

In addition, our diversified businesses classify some of their investments in marketable equity securities as available-for-sale securities. We include any unrealized gains or losses on these securities in "Accumulated other comprehensive (loss) income" in our Consolidated Statements of Common Shareholders' Equity on page 45 and in the Consolidated Statements of Capitalization on page 47. We also include our diversified businesses' portion of unrealized gains or losses on securities of equity-method (described earlier in this note) investees in our Consolidated Statements of Common Shareholders' Equity.

**Evaluation of Assets for Impairment**
SFAS No. 121, *Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of*, applies particular requirements to some of our assets that have long lives (some examples are utility property and equipment and real estate). We determine if those assets are impaired by comparing their undiscounted expected future cash flows to their carrying amount in our accounting records. We recognize an impairment loss if the undiscounted expected future cash flows are less than the carrying amount of the asset. See Note 4 on page 59 for further discussion.

## Utility Plant, Depreciation, Amortization, and Decommissioning

*Utility Plant*

Utility plant is the term we use to describe our utility business property and equipment that is in use, being held for future use, or under construction. We summarize utility plant in our Consolidated Balance Sheets. We report our utility plant at its original cost, unless impaired under the provisions of SFAS No. 121. Our original cost includes:

- material and labor,
- contractor costs,
- construction overhead costs (where applicable), and
- an allowance for funds used during construction (described later in this note).

We charge retired or otherwise-disposed-of utility plant to accumulated depreciation.

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 $156 million at December 31, 1999 and $152 million at December 31, 1998. We report these properties in the same accounts we use for our other utility plant (described above).

*Depreciation Expense*

Generally, we compute depreciation by applying composite, straight-line rates (approved by the Maryland PSC) to the average investment in classes of depreciable property. We depreciate vehicles based on their estimated useful lives.

*Amortization Expense*

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

*Decommissioning Costs*

We must accumulate a reserve for the costs that we expect to incur in the future to decommission the radioactive portion of Calvert Cliffs. We do this based on a sinking fund methodology. The Maryland PSC authorized us to record decommissioning expense based on a facility-specific cost estimate so we can accumulate a decommissioning reserve of $521 million in 1993 dollars by the end of Calvert Cliffs' service life in 2016, adjusted to reflect expected inflation. We have reported the decommissioning reserve in "Accumulated depreciation" in our Consolidated Balance Sheets. The total reserve was $287.5 million at December 31, 1999 and $244.0 million at December 31, 1998.

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

## Allowance for Funds Used During Construction and Capitalized Interest

*Allowance for Funds Used During Construction (AFC)*

We finance 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 plant is placed in service.

The AFC rates are 9.04% for gas plant, 9.35% for common plant, and 9.40% for electric plant. We compound AFC annually.

*Capitalized Interest*

With the issuance of the Restructuring Order, we ceased accruing AFC for electric generation-related construction projects and began using SFAS No. 34, *Capitalizing Interest Costs*, to calculate the cost during construction of debt funds used to finance our electric generation-related construction projects.

Our diversified businesses capitalize interest costs incurred to finance real estate developed for internal use and certain power projects.

### Long-Term Debt

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

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

### Cash Flows

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

### Use of Accounting Estimates

Management makes estimates and assumptions when preparing financial statements under generally accepted accounting principles. These estimates and assumptions affect various matters, including:

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

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

### Reclassifications

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

### Accounting Standards Issued

In July 1999, the FASB issued SFAS No. 137 that delays the effective date for SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, by one year. Therefore, we must adopt the provisions of SFAS No. 133 in our financial statements for the quarter ended March 31, 2001. We have not determined the effects of SFAS No. 133 on our financial results.

## Note 2.

## Information by Operating Segment

We have three reportable operating segments—Electric, Gas, and Energy Services:

- Our Electric business generates, purchases, and sells electricity,
- Our Gas business purchases, transports, and sells natural gas, and
- Our Energy Services businesses consist of certain diversified businesses that:
  - develop, own, and operate power projects,
  - provide power marketing and risk management services,
  - provide nuclear consulting services,
  - sell natural gas through mass marketing efforts,
  - sell and service electric and gas appliances, heating and air conditioning systems, and engage in home improvements, and
  - provide cooling services to commercial customers in Baltimore.

Our remaining diversified businesses:

- engage in financial investments, and
- develop, own, and manage real estate and senior-living facilities.

These reportable segments are strategic businesses based principally upon regulations, products, and services that require different technology and marketing strategies. The segments have the same accounting policies as those described in the summary of significant accounting policies in Note 1. The Company evaluates 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 page 55.

We are realigning our organization combining all of our domestic merchant energy businesses. We have not determined the impact of this reorganization on our operating segments, but such changes will impact our operating segments in the future.

| | Electric Business | Gas Business | Energy Services Businesses | Other Diversified Businesses | Unallocated Corporate Items (a) | Eliminations | Consolidated |
|---|---|---|---|---|---|---|---|
| | | | | *(In millions)* | | | |
| **1999** | | | | | | | |
| Unaffiliated revenues | **$2,258.8** | **$476.5** | **$ 937.0** | **$113.9** | **$ –** | **$ –** | **$3,786.2** |
| Intersegment revenues | **1.2** | **11.6** | **30.4** | **(0.4)** | **–** | **(42.8)** | **–** |
| Total revenues | **2,260.0** | **488.1** | **967.4** | **113.5** | **–** | **(42.8)** | **3,786.2** |
| Depreciation and amortization | **376.4** | **44.9** | **23.1** | **5.2** | **0.2** | **–** | **449.8** |
| Equity in income of equity-method investees (b) | **5.1** | **–** | **–** | **–** | **–** | **–** | **5.1** |
| Net interest expense | **162.4** | **24.4** | **24.6** | **31.1** | **0.4** | **(1.4)** | **241.5** |
| Income tax expense (benefit) | **149.2** | **18.1** | **34.8** | **(12.1)** | **(0.9)** | **(2.7)** | **186.4** |
| Extraordinary loss | **66.3** | **–** | **–** | **–** | **–** | **–** | **66.3** |
| Net income (loss) (c) | **198.8** | **33.0** | **50.6** | **(19.3)** | **(1.7)** | **(1.3)** | **260.1** |
| Segment assets | **6,312.6** | **915.3** | **1,681.2** | **743.2** | **129.2** | **(97.7)** | **9,683.8** |
| Utility construction expenditures | **322.1** | **63.8** | **–** | **–** | **–** | **–** | **385.9** |
| **1998** | | | | | | | |
| Unaffiliated revenues | $2,219.2 | $449.4 | $ 524.1 | $165.4 | $ – | $ – | $3,358.1 |
| Intersegment revenues | 1.6 | 1.7 | 12.0 | 0.5 | – | (15.8) | – |
| Total revenues | 2,220.8 | 451.1 | 536.1 | 165.9 | – | (15.8) | 3,358.1 |
| Depreciation and amortization | 313.0 | 45.4 | 9.2 | 9.3 | 0.2 | – | 377.1 |
| Equity in income of equity-method investees (b) | 5.0 | – | – | – | – | – | 5.0 |
| Net interest expense | 164.9 | 23.6 | 16.0 | 38.6 | (1.9) | (0.3) | 240.9 |
| Income tax expense (benefit) | 146.6 | 13.4 | 34.1 | (15.8) | (0.1) | – | 178.2 |
| Net income (loss) (d) | 259.6 | 26.1 | 43.4 | (24.2) | (0.1) | 1.1 | 305.9 |
| Segment assets | 6,342.8 | 934.6 | 1,315.0 | 811.6 | (14.0) | (115.0) | 9,275.0 |
| Utility construction expenditures | 279.0 | 60.4 | – | – | – | – | 339.4 |
| **1997** | | | | | | | |
| Unaffiliated revenues | $2,191.7 | $521.6 | $ 399.4 | $194.9 | $ – | $ – | $3,307.6 |
| Intersegment revenues | 0.3 | – | 0.6 | 9.7 | – | (10.6) | – |
| Total revenues | 2,192.0 | 521.6 | 400.0 | 204.6 | – | (10.6) | 3,307.6 |
| Depreciation and amortization | 286.5 | 39.3 | 6.9 | 9.9 | 0.3 | – | 342.9 |
| Equity in income of equity-method investees (b) | 5.0 | – | – | – | – | – | 5.0 |
| Net interest expense | 160.7 | 20.3 | 10.1 | 32.5 | 6.4 | – | 230.0 |
| Income tax expense (benefit) | 135.7 | 13.9 | 23.8 | (13.5) | (1.9) | – | 158.0 |
| Net income (loss) (e) | 224.0 | 25.6 | 27.5 | (21.1) | (3.6) | 1.7 | 254.1 |
| Segment assets | 6,404.4 | 907.7 | 700.9 | 885.4 | 10.7 | (9.1) | 8,900.0 |
| Utility construction expenditures | 278.7 | 94.5 | – | – | – | – | 373.2 |

(a) We do not allocate certain items presented in the table for Constellation Energy Group and a holding company for our diversified businesses.

(b) Our Energy Services and our Other Diversified businesses record their equity in the income of equity method investees in their unaffiliated revenues.

(c) Our Electric business recorded costs of $4.9 million after-tax related to Hurricane Floyd as discussed in the "Electric Operations and Maintenance Expenses" section of Management's Discussion and Analysis on page 28. Our Other Diversified businesses recorded a $16.0 million write-down of its investment in Capital Re stock to reflect the market value of this investment as discussed in Note 3 and a $5.8 million write-down of certain senior-living facilities as discussed in the "Other Diversified Businesses" section of Management's Discussion and Analysis on page 33. In addition, our Energy Services businesses recorded $18.7 million in write-downs of certain power projects as discussed in Note 3.

(d) Our Energy Services businesses recorded $10.4 million for its share of earnings in a partnership as discussed in Note 3 and a $5.5 million write-off of an energy services investment as discussed in the "Other Energy Services" section of Management's Discussion and Analysis on page 33. In addition, our Other Diversified businesses recorded a $15.4 million write-down of a real estate project as discussed in Note 3.

(e) Our Electric business recorded a $37.5 million write-off related to the terminated merger with Potomac Electric Power Company as discussed in the "Other Income and Expenses" section of Management's Discussion and Analysis on page 34. In addition, our Other Diversified businesses recorded a $46.0 million write-down of two real estate projects as discussed in Note 3.

## Note 3.

### Investments

**Real Estate Projects and Investments**

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

| *At December 31,* | **1999** | 1998 |
|---|---|---|
| | *(In millions)* | |
| Properties under development | **$197.8** | $210.6 |
| Rental and operating properties (net of accumulated depreciation) | **9.2** | 38.9 |
| Equity interest in real estate investment trust | **103.1** | 104.0 |
| Other real estate ventures | **–** | 0.4 |
| Total real estate projects and investments | **$310.1** | $353.9 |

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

In 1998, CREG recorded a $15.4 million after-tax write-down of the investment in Church Street Station that occurred because the fair value of the project declined based upon competitive bids.

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

In exchange, COPT received 14 operating properties and two properties under development from CREG as well as certain other assets, options, and first refusal rights. These options and first refusal rights are related to approximately 91 acres of identified properties which are adjacent to operating properties acquired by COPT. At December 31, 1999, 48 acres remain under these options and first refusal rights and have terms that range from 1 to 4 years.

In 1997, CREG recorded the following write-downs of real estate projects:

- a $14.1 million after-tax write-down of the investment in Church Street Station that occurred because CREG decided to sell rather than keep the project, and
- a $31.9 million after-tax write-down of the investment in Piney Orchard—a mixed-use, planned-unit development—that occurred because the expected future cash flow from the project was less than CREG's investment in the project.

**Power Projects**

Power projects held by our diversified businesses consist of the following:

| *At December 31,* | **1999** | 1998 |
|---|---|---|
| | *(In millions)* | |
| Domestic | | |
| East | **$ 55.7** | $ 46.0 |
| West | **475.6** | 427.4 |
| International | | |
| South America | **12.3** | 21.6 |
| Central America | **241.8** | 248.1 |
| Total power projects | **$785.4** | $743.1 |

Our Domestic-West power projects include investments of $301.8 million in 1999 and $310.6 in 1998 that sell electricity in California under power purchase agreements called "Interim Standard Offer No. 4" agreements. We discuss these projects further in Note 10 on page 71.

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

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

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

## Financial Investments

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

| *At December 31,* | **1999** | 1998 |
|---|---|---|
| | *(In millions)* | |
| Insurance company | $ – | $102.5 |
| Marketable equity securities | **84.2** | 25.3 |
| Financial limited partnerships | **35.8** | 41.9 |
| Leveraged leases | **25.4** | 28.3 |
| Total financial investments | **$145.4** | $198.0 |

In 1999, our financial investments business announced that it would exchange its shares of common stock in Capital Re, an insurance company, for common stock of ACE Limited (ACE), another insurance company, as part of a business combination whereby ACE would acquire all of the outstanding capital stock of Capital Re. Through September 30, 1999, our financial investments business wrote-down its $94.2 million investment in Capital Re stock by $20.9 million after-tax to reflect the market value of this investment. The agreement between ACE and Capital Re was subsequently revised on a more favorable basis for Capital Re to include both cash and ACE stock. In December 1999, the transaction was finalized and our financial investments business recorded a $4.9 million after-tax gain on this investment to reflect the closing price of the business combination. As a result of this business combination, this investment no longer qualifies as an equity-method investment. Accordingly, in 1999, we have included this investment in the marketable equity securities amount above.

### *Investments Classified as Available-for-Sale*

We classify our investments in the nuclear decommissioning trust fund as available-for-sale. In addition, we classify some of our diversified businesses' marketable equity securities (shown above) as available-for-sale. This means we do not expect to hold them to maturity and we do not consider them trading securities.

We show the fair values, gross unrealized gains and losses, and amortized cost bases for all of our available-for-sale securities, exclusive of $6.2 million in 1998 of unrealized net gains on securities held by Capital Re as an equity method investee, in the following tables.

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

| *At December 31, 1998* | Amortized Cost Basis | Unrealized Gains | Unrealized Losses | Fair Value |
|---|---|---|---|---|
| | | *(In millions)* | | |
| Marketable equity securities | $ 82.9 | $24.2 | $(0.4) | $106.7 |
| Corporate debt and U.S. Government agency | 12.7 | 0.4 | – | 13.1 |
| State municipal bonds | 64.8 | 2.7 | – | 67.5 |
| Totals | $160.4 | $27.3 | $(0.4) | $187.3 |

The above tables include $40.5 million in 1999 and $23.9 million in 1998 of unrealized net gains associated with the nuclear decommissioning trust fund which are reflected as a change in the nuclear decommissioning trust fund on the Consolidated Balance Sheets.

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

| *Year Ended December 31,* | **1999** | 1998 | 1997 |
|---|---|---|---|
| | | *(In millions)* | |
| Gross realized gains | **$11.7** | $4.2 | $9.3 |
| Gross realized losses | **(38.8)** | (0.7) | (0.6) |
| Net realized (losses) gains | **$(27.1)** | $3.5 | $8.7 |

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

| *At December 31, 1999* | Amount |
|---|---|
| | *(In millions)* |
| Less than 1 year | $ 1.0 |
| 1–5 years | 46.4 |
| 5–10 years | 21.8 |
| More than 10 years | 18.6 |
| Total maturities of debt securities | $87.8 |

## Note 4.

### Rate Matters and Accounting Impacts of Deregulation

On April 8, 1999, Maryland enacted the Electric Customer Choice and Competition Act of 1999 (the "Act") and accompanying tax legislation that will significantly restructure Maryland's electric utility industry and modify 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 will be 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 will continue to apply to transmission and distribution revenue. Additionally, all electric and natural gas utility results will become subject to the Maryland corporate income tax.

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

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

- All customers, except a few commercial and industrial companies that have signed contracts with BGE, will be able to choose their electric energy supplier beginning July 1, 2000. BGE will provide a standard offer service for customers that do not select an alternative supplier. In either case, BGE will continue to deliver electricity to all customers in areas traditionally served by BGE.
- BGE's current electric base rates are frozen at their current levels until July 1, 2000.
- BGE will reduce 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 will have up to four service options that will fix electric energy rates and transition charges for a period that generally ranges from four to six years.
- Electric delivery service rates will be frozen for a four year period for commercial and industrial customers. The generation and transmission components of rates will be frozen for different time periods depending on the service options selected by those customers.
- BGE will be allowed to recover $528 million after-tax of its potentially stranded investments and utility restructuring costs through a competitive transition charge on customers' bills. Residential customers will pay this charge for six years. Commercial and industrial customers will pay in a lump sum or over the four to six-year period, depending on the service option selected by each customer.
- Generation-related regulatory assets and nuclear decommissioning costs will be included in delivery service rates effective July 1, 2000 and will be recovered on a basis approximating their existing amortization schedules.
- Starting July 1, 2000, BGE will unbundle rates to show separate components for delivery service, transition charges, standard offer services (generation), transmission, universal service, and taxes.
- On July 1, 2000, BGE will transfer, 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 will reduce its generation assets, as described later in this section, by $150 million pre-tax during the period July 1, 1999 – June 30, 2000 to mitigate a portion of its potentially stranded investments.
- Universal service will be 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 49, 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 provides for the creation of a single, new generation-related regulatory asset to be recovered through BGE's regulated transmission and distribution business. We discuss this further in Note 5 on page 60.

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 of evaluating and measuring impairment under the provisions of SFAS No. 121 involves two steps. First, we must compare the net book value of each generating plant to the estimated undiscounted future net operating cash flows from that plant. An electric generating plant is considered impaired when its undiscounted future net operating cash flows are less than its net book value. Second, we compute 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 exceeds its fair value, we must record a write-down.

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

BGE has contracts to purchase electric capacity and energy that are expected to be uneconomic upon the deregulation of electric generation. Therefore, we recorded a $34.2 million after-tax charge based on the net present value of the excess of estimated contract costs over the market-based revenues to recover these costs over the remaining terms of the contracts. In addition, BGE has deferred certain energy conservation expenditures that will not be recovered through its transmission and distribution business under the Restructuring Order. Accordingly, we recorded a $10.3 million after-tax charge to eliminate the regulatory asset previously established for these deferred expenditures.

At December 31, 1999, the total charge for BGE's electric generating plants that are 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 will be amortized as it is recovered from ratepayers through June 30, 2000. This will accomplish the $150 million reduction of its generation plants required by the Restructuring Order.

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

## Note 5.

### Regulatory Assets (net)

As discussed in Note 1 on page 49, 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 generally accepted accounting principles. 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,* | **1999** | 1998 |
|---|---|---|
| | *(In millions)* | |
| Generation plant reduction recoverable in current rates | **$ 75.0** | $ – |
| Electric generation-related regulatory asset | **286.6** | – |
| Income taxes recoverable through future rates (net) | **110.4** | 252.6 |
| Deferred postretirement and postemployment benefit costs | **41.9** | 90.0 |
| Deferred nuclear expenditures | **–** | 73.3 |
| Deferred conservation expenditures | **12.9** | 53.4 |
| Deferred costs of decommissioning federal uranium enrichment facilities | **–** | 38.5 |
| Deferred environmental costs | **31.3** | 33.4 |
| Deferred fuel costs (net) | **73.8** | 12.7 |
| Other (net) | **5.5** | 11.8 |
| Total regulatory assets (net) | **$637.4** | $565.7 |

#### Generation Plant Reduction Recoverable in Current Rates

As a condition of the Maryland PSC's consolidation of the September 3, 1998 Office of People's Counsel petition to lower electric base rates with BGE's electric restructuring transition proposal, we agreed to make our rates subject to refund effective July 1, 1999. Under the Restructuring Order, BGE's rates are frozen through June 30, 2000. However, BGE was required to record a reduction to its generation plant of $150 million which it will recover through its current rates between July 1, 1999 and June 30, 2000. BGE recorded a $150 million regulatory asset for the required generation plant reduction that will be amortized as it is recovered from ratepayers through June 30, 2000.

#### Electric Generation-Related Regulatory Asset

With the issuance of the Restructuring Order, BGE no longer met the requirements for the application of SFAS No. 71 for the electric generation portion of its business. In accordance with SFAS No. 101 and EITF 97-4, all individual generation-related regulatory assets and liabilities must be eliminated from our balance sheet unless these regulatory assets and liabilities will be recovered in the regulated portion of the business. Pursuant to the Restructuring Order, BGE wrote-off all of its individual, generation-related regulatory assets and liabilities. A single, new generation-related regulatory asset was established for amounts to be collected through BGE's regulated transmission and distribution business. The new regulatory asset will be 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 51, income taxes recoverable through future rates is the portion of our net deferred income tax liability that is applicable to our utility business, but has not been reflected in the rates we charge our customers. These income taxes represent the tax effect of temporary differences in depreciation and the allowance for equity funds used during construction, offset by differences in deferred tax rates and deferred taxes on deferred investment tax credits. We amortize these amounts as the temporary differences reverse.

In 1999, the electric generation-related portion of this regulatory asset is included in the electric generation-related regulatory asset discussed earlier in this note.

### Deferred Postretirement and Postemployment Benefit Costs

Deferred postretirement and postemployment benefit costs are the costs we recorded under SFAS No. 106 (for postretirement benefits) and No. 112 (for postemployment benefits) in excess of the costs we included in the rates we charge our customers. We began amortizing these costs over a 15-year period in 1998. We discuss these costs further in Note 6 on page 62.

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

### Deferred Nuclear Expenditures

Deferred nuclear expenditures are the net unamortized balance of certain operations and maintenance costs at Calvert Cliffs. These expenditures consist of:

- costs incurred from 1979 through 1982 for inspecting and repairing seismic pipe supports,
- expenditures incurred from 1989 through 1994 associated with nonrecurring phases of certain nuclear operations projects, and
- expenditures incurred during 1990 for investigating leaks in the pressurizer heater sleeves.

In 1999, these expenditures were reclassified to the electric generation-related regulatory asset discussed earlier in this note.

### Deferred Conservation Expenditures

Deferred conservation expenditures include two components:

- operations costs (labor, materials, and indirect costs) associated with conservation programs approved by the Maryland PSC, which we are amortizing over periods of four to five years in accordance with the Maryland PSC's orders, and
- revenues we collected from customers in 1996 in excess of our profit limit under the conservation surcharge.

In 1999, we wrote-off a portion of the unamortized electric conservation expenditures that will not be recovered under the Restructuring Order as discussed in Note 4 on page 59.

### Deferred Costs of Decommissioning Federal Uranium Enrichment Facilities

Deferred costs of decommissioning federal uranium enrichment facilities are the unamortized portion of our required contributions to a fund for decommissioning and decontaminating the Department of Energy's uranium enrichment facilities. We are required, along with other domestic utilities, by the Energy Policy Act of 1992 to make contributions to the fund. 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 are amortizing these costs over the contribution period as a cost of fuel. We also discuss this in Note 1 on page 50.

In 1999, these expenditures were reclassified to the electric generation-related regulatory asset discussed earlier in this note.

### Deferred Environmental Costs

Deferred environmental costs are the estimated costs of investigating and cleaning up contaminated sites we own. We discuss this further in Note 10 on page 69. We are amortizing $21.6 million of these costs (the amount we had incurred through October 1995) over a 10-year period in accordance with the Maryland PSC's November 1995 order.

### Deferred Fuel Costs

As described in Note 1 on page 50, 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,* | **1999** | 1998 |
|---|---|---|
| | *(In millions)* | |
| Electric | **$60.0** | $(11.5) |
| Gas | **13.8** | 24.2 |
| Deferred fuel costs (net) | **$73.8** | $ 12.7 |

Under the Restructuring Order, BGE's electric fuel rate clause will be discontinued effective July 1, 2000. After that date, earnings will be affected by the changes in the cost of fuel and energy. In addition, any accumulated difference between our actual costs of fuel and energy and the amounts collected from customers under the electric fuel rate clause will be collected from our customers over a period to be determined by the Maryland PSC.

## Note 6.

### Pension, Postretirement, Other Postemployment, and Employee Savings Plan Benefits

We offer pension, postretirement, other postemployment, and employee savings plan benefits. We describe each of these separately below.

**Pension Benefits**

We sponsor several defined benefit pension plans for our employees. A defined benefit plan specifies the amount of benefits a plan participant is to receive using information about the participant. Our employees do not contribute to these plans. Generally, we calculate the benefits under these plans based on age, years of service, and pay.

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

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

- eligible participants will be 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 will be 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 on page 63.

Also during 1999, our Board of Directors approved a Targeted Voluntary Special Early Retirement Program (TVSERP) to provide enhanced early retirement benefits to certain eligible participants in targeted jobs that elect to retire on June 1, 2000. The financial impacts of the TVSERP will be reflected in the second quarter of 2000.

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, 1999 were mostly marketable equity and fixed income securities, and group annuity contracts.

**Postretirement Benefits**

We sponsor defined benefit postretirement health care and life insurance plans which cover nearly all Constellation Energy and BGE employees, and certain employees of our subsidiaries. Generally, we calculate the benefits under these plans based on age, years of service, and pension benefit levels. We do not fund these plans.

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

Effective January 1, 1993, we adopted SFAS No. 106, *Employers' Accounting for Postretirement Benefits Other Than Pensions*. The adoption of that statement caused:

- a transition obligation, which we are amortizing over 20 years, and
- an increase in annual postretirement benefit costs.

For our diversified businesses, we expense all postretirement benefit costs. For our utility business, we accounted for the increase in annual postretirement benefit costs under two Maryland PSC rate orders:

- in an April 1993 rate order, the Maryland PSC allowed us to expense one-half and defer, as a regulatory asset (see Note 5), the other half of the increase in annual postretirement benefit costs related to our 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 gas business.

Beginning in 1998, the Maryland PSC authorized us to:

- expense all of the increase in annual postretirement benefit costs related to our electric business, and
- amortize the regulatory asset for postretirement benefit costs related to our electric and gas businesses over 15 years.

## Obligations, Assets, and Funded Status

We show the change in the benefit obligations, plan assets, and funded status of the pension and postretirement benefit plans in the following table:

| | Pension Benefits | | Postretirement Benefits | |
|---|---|---|---|---|
| | **1999** | 1998 | **1999** | 1998 |
| | *(In millions)* | | | |
| **Change in benefit obligation** | | | | |
| Benefit obligation at January 1 | **$1,031.3** | $ 902.0 | **$383.1** | $320.3 |
| Service cost | **26.1** | 21.6 | **8.6** | 6.6 |
| Interest cost | **65.3** | 63.0 | **24.4** | 23.4 |
| Plan participants' contributions | **–** | – | **2.0** | 2.0 |
| Actuarial (gain) loss | **(93.0)** | 102.9 | **(34.2)** | 48.9 |
| Plan amendments | **44.6** | – | **(5.0)** | – |
| Benefits paid | **(57.6)** | (58.2) | **(20.2)** | (18.1) |
| Benefit obligation at December 31 | **$1,016.7** | $1,031.3 | **$358.7** | $383.1 |

| | Pension Benefits | | Postretirement Benefits | |
|---|---|---|---|---|
| | **1999** | 1998 | **1999** | 1998 |
| | *(In millions)* | | | |
| **Change in plan assets** | | | | |
| Fair value of plan assets at January 1 | **$ 985.5** | $912.3 | **$ –** | $ – |
| Actual return on plan assets | **139.4** | 116.9 | **–** | – |
| Employer contribution | **17.6** | 14.5 | **18.2** | 16.1 |
| Plan participants' contributions | **–** | – | **2.0** | 2.0 |
| Benefits paid | **(57.6)** | (58.2) | **(20.2)** | (18.1) |
| Fair value of plan assets at December 31 | **$1,084.9** | $985.5 | **$ –** | $ – |

| | Pension Benefits | | Postretirement Benefits | |
|---|---|---|---|---|
| | **1999** | 1998 | **1999** | 1998 |
| | *(In millions)* | | | |
| **Funded Status** | | | | |
| Funded status at December 31 | **$ 68.2** | $(45.8) | **$(358.7)** | $(383.1) |
| Unrecognized net actuarial (gain) loss | **(27.2)** | 137.6 | **23.6** | 59.7 |
| Unrecognized prior service cost | **59.0** | 16.9 | **(0.1)** | – |
| Unrecognized transition obligation | **–** | – | **143.4** | 159.3 |
| Unamortized net asset from adoption of SFAS No. 87 | **(0.5)** | (0.7) | **–** | – |
| Prepaid (accrued) benefit cost | **$ 99.5** | $108.0 | **$(191.8)** | $(164.1) |

## Net Periodic Benefit Cost

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

| *Year Ended December 31,* | **1999** | 1998 | 1997 |
|---|---|---|---|
| | *(In millions)* | | |
| **Components of net periodic pension benefit cost** | | | |
| Service cost | **$26.1** | $21.6 | $16.8 |
| Interest cost | **65.3** | 63.0 | 61.3 |
| Expected return on plan assets | **(76.6)** | (72.1) | (66.9) |
| Amortization of transition obligation | **(0.2)** | (0.2) | (0.2) |
| Amortization of prior service cost | **2.5** | 2.5 | 2.5 |
| Recognized net actuarial loss | **10.1** | 5.6 | 4.6 |
| Amount capitalized as construction cost | **(4.2)** | (3.8) | (2.5) |
| Net periodic pension benefit cost | **$23.0** | $16.6 | $15.6 |

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

| *Year Ended December 31,* | **1999** | 1998 | 1997 |
|---|---|---|---|
| | | *(In millions)* | |
| **Components of net periodic postretirement benefit cost** | | | |
| Service cost | **$ 8.6** | $ 6.6 | $ 5.4 |
| Interest cost | **24.4** | 23.4 | 21.8 |
| Amortization of transition obligation | **11.0** | 11.4 | 11.4 |
| Recognized net actuarial loss | **1.9** | 0.2 | 0.1 |
| Amount capitalized as construction cost | **(9.4)** | (8.1) | (7.6) |
| Amount deferred | **–** | – | (7.2) |
| Net periodic postretirement benefit cost | **$36.5** | $33.5 | $23.9 |

### Assumptions

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

| | Pension Benefits | | Postretirement Benefits | |
|---|---|---|---|---|
| *At December 31,* | **1999** | 1998 | **1999** | 1998 |
| Discount rate | **7.25%** | 6.50% | **7.25%** | 6.50% |
| 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 1999, 6.0% for both Medicare-eligible retirees and retirees not covered by Medicare, and
- in 2000, 7.0% for Medicare-eligible retirees and 8.5% for retirees not covered by Medicare.

After 2000, we assumed both inflation rates will decrease by 0.5% annually to a rate of 5.5% in the years 2003 and 2006, respectively. After these dates, the inflation rate will remain at 5.5%.

A one-percent increase in the health care inflation rate from the assumed rates would increase the accumulated postretirement benefit obligation by approximately $46.7 million as of December 31, 1999 and would increase the combined service and interest costs of the postretirement benefit cost by approximately $5.4 million annually.

A one-percent decrease in the health care inflation rate from the assumed rates would decrease the accumulated postretirement benefit obligation by approximately $37.4 million as of December 31, 1999 and would decrease the combined service and interest costs of the postretirement benefit cost by approximately $4.2 million annually.

### Other Postemployment Benefits

We provide the following postemployment benefits:

- health and life insurance benefits to our employees and certain employees of our subsidiaries who are found to be disabled under our Disability Insurance Plan, and
- income replacement payments for employees found to be disabled before November 1995 (payments for employees found to be disabled after that date are paid by an insurance company, and the cost is paid by employees).

The liability for these benefits totaled $46.5 million as of December 31, 1999 and $52.9 million as of December 31, 1998.

Effective December 31, 1993, we adopted SFAS No. 112, *Employers' Accounting for Postemployment Benefits.* We deferred, as a regulatory asset (see Note 5 on page 61), the postemployment benefit liability attributable to our 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 current electric and gas base rates to recover the higher costs in 1998.

We assumed the discount rate for other postemployment benefits to be 5.5% in 1999 and 4.5% in 1998.

### Employee Savings Plan Benefits

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

- $10.4 million in 1999,
- $10.1 million in 1998, and
- $8.5 million in 1997.

## Note 7.

### Short-Term Borrowings

Our short-term borrowings may include bank loans, commercial paper notes, 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**

At December 31, 1999, Constellation Energy had $242.5 million outstanding consisting entirely of commercial paper notes. At December 31, 1998, no short-term borrowings were outstanding since Constellation Energy was not established until April 30, 1999 as discussed in Note 1 on page 49.

In 1999, Constellation Energy arranged a $135 million revolving credit agreement for short-term financial needs, including letters of credit. This agreement also supports Constellation Energy's commercial paper notes. This facility replaced a similar facility at one of Constellation Energy's diversified businesses. At December 31, 1999, letters of credit totaling $23.1 million were issued under this facility.

In addition, Constellation Energy had unused committed bank lines of credit totaling $35 million and interim lines totaling $125 million supporting its commercial paper notes at December 31, 1999.

The weighted average effective interest rate for Constellation Energy's commercial paper notes was 5.68% for the year ended December 31, 1999.

**BGE**

At December 31, 1999, BGE had $129.0 million outstanding consisting entirely of commercial paper notes. At December 31, 1998, BGE had no short-term borrowings outstanding.

At December 31, 1999, BGE had unused committed bank lines of credit totaling $123 million supporting the commercial paper notes compared to $113 million at December 31, 1998. These amounts do not include unused revolving credit agreements of $60 million at December 31, 1999 and $100 million at December 31, 1998 that are discussed in Note 8 on page 66.

The weighted average effective interest rates for BGE's commercial paper notes were 5.25% for the year ended December 31, 1999 and 5.65% for 1998.

## Note 8.

### Long-Term Debt

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

**BGE**

*BGE's First Refunding Mortgage Bonds*

BGE's first refunding mortgage bonds are secured by a mortgage lien on nearly all of its assets, including all utility properties and franchises and its subsidiary capital stock. Capital stock pledged under the mortgage is that of Safe Harbor Water Power Corporation and Constellation Enterprises, Inc. When BGE transfers its generating assets to subsidiaries of Constellation Energy, these assets will remain subject to the lien of BGE's mortgage. However, BGE will remain liable for this debt after the assets are transferred.

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:

- 5½% Installment Series, due 2002
- 5½% Series, due 2000
- 8⅜% Series, due 2001
- 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*
We show the weighted-average interest rates and maturity dates for BGE's fixed-rate medium-term notes outstanding at December 31, 1999 in the following table.

| Series | Weighted-Average Interest Rate | Maturity Dates |
|---|---|---|
| B | 8.10% | 2000-2006 |
| C | 7.33 | 2000-2003 |
| D | 6.66 | 2001-2006 |
| E | 6.66 | 2006-2012 |
| G | 6.08 | 2001-2008 |

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

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

BGE has $60 million of revolving credit agreements with several banks that are available through 2000. At December 31, 1999, BGE had no outstanding borrowings under these agreements. These banks charge us commitment fees based on the daily average of the unborrowed amount, and we pay market interest rates on any borrowings. These agreements also support BGE's commercial paper notes, as described in Note 7 on page 65.

*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 the Consolidated Statements of Income and is deductible for income tax purposes.

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

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

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

**Diversified Businesses**

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

*Mortgage and Construction Loans*
Our diversified businesses' mortgage and construction loans have varying terms. The following mortgage notes require monthly principal and interest payments:

- 7.90%, due in 2000
- 8.00%, due in 2001
- 4.25%, due in 2009
- 9.65%, due in 2028
- 8.00%, due in 2033

The 8.00% mortgage note due in 2003 requires interest payments until maturity. The variable rate mortgage notes and construction loans require periodic payment of principal and interest.

*Unsecured Notes*
The unsecured notes mature on the following schedule:

| | Amount |
|---|---|
| | *(In millions)* |
| 7.125%, due March 13, 2000 | $ 15.0 |
| 7.55%, due April 22, 2000 | 35.0 |
| 7.50%, due May 5, 2000 | 139.0 |
| 7.43%, due September 9, 2000 | 30.0 |
| 5.43% due October 15, 2000 | 5.0 |
| 7.66%, due May 5, 2001 | 135.0 |
| 5.67%, due May 5, 2001 | 152.0 |
| Total unsecured notes at December 31, 1999 | $511.0 |

**Maturities of Long-Term Debt**

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

| Year | BGE | Diversified Businesses |
|---|---|---|
| | *(In millions)* | |
| 2000 | $ 401.9 | $284.4 |
| 2001 | 282.2 | 366.6 |
| 2002 | 154.0 | 1.5 |
| 2003 | 286.8 | 10.4 |
| 2004 | 154.0 | 6.0 |
| Thereafter | 1,428.6 | 17.9 |
| Total long-term debt at December 31, 1999 | $2,707.5 | $686.8 |

At December 31, 1999, BGE had long-term loans totaling $255.0 million that mature after 2002 (including $110.0 million of medium-term notes discussed in this Note under "BGE's Other Long-Term Debt") that lenders could potentially require us to repay early. Of this amount, $145.0 million could be repaid in 2000, $60.0 million in 2002, and $50.0 million thereafter. At December 31, 1999, $122.0 million is classified as current portion of long-term debt as a result of these provisions.

**Weighted Average Interest Rates for Variable Rate Debt**

Our weighted average interest rates for variable rate debt were:

| *Year Ended December 31,* | **1999** | 1998 |
|---|---|---|
| *BGE* | | |
| Floating rate series mortgage bonds | **5.41%** | 5.90% |
| Remarketed floating rate series mortgage bonds | **5.19** | 5.70 |
| Medium-term notes, Series D | **5.29** | 5.74 |
| Medium-term notes, Series G | **5.38** | – |
| Medium-term notes, Series H | **5.64** | – |
| Pollution control loan | **3.22** | 3.48 |
| Port facilities loan | **3.24** | 3.61 |
| Adjustable rate pollution control loan | **3.59** | 3.75 |
| Economic development loan | **3.26** | 3.59 |
| Variable rate pollution control loan | **3.30** | 3.45 |
| *Diversified Businesses* | | |
| Loans under credit agreement | **5.68** | 6.02 |
| Mortgage and construction loans | **6.65** | 8.17 |

## Note 9.

### Leases

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

**Outgoing Lease Payments**

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

Lease expense was:

- $12.2 million in 1999,
- $10.5 million in 1998, and
- $9.5 million in 1997.

At December 31, 1999, we owed future minimum payments for long-term, noncancelable, operating leases as follows:

| Year | *(In millions)* |
|---|---|
| 2000 | $ 8.2 |
| 2001 | 6.1 |
| 2002 | 4.5 |
| 2003 | 3.2 |
| 2004 | 2.4 |
| Thereafter | 9.7 |
| Total future minimum lease payments | $34.1 |

## Note 10.

### Commitments, Guarantees, and Contingencies

#### Commitments

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

- $67.8 million in 1999,
- $70.7 million in 1998, and
- $65.6 million in 1997.

At December 31, 1999, we estimate our future payments for capacity and energy that we are obligated to buy under these contracts to be:

| Year | *(In millions)* |
|---|---|
| 2000 | $ 69.7 |
| 2001 | 37.1 |
| 2002 | 13.9 |
| 2003 | 13.8 |
| 2004 | 13.6 |
| Thereafter | 113.4 |
| Total estimated future payments for capacity and energy under long-term contracts | $261.5 |

Portions of these contracts are expected to be uneconomic upon the deregulation of electric generation. Therefore, we recorded a charge and accrued a corresponding liability based on the net present value of the excess of estimated contract costs over the market based revenues to recover these costs over the remaining terms of the contracts as discussed in Note 4 on page 59. At December 31, 1999, the accrued portion of these contracts was $47.5 million.

Some of our diversified businesses have committed to contribute additional capital and to make additional loans to some affiliates, joint ventures, and partnerships in which they have an interest. At December 31, 1999, the total amount of investment requirements committed to by our diversified businesses was $174.2 million. This amount includes $121 million for our energy services businesses commitment to Orion Power Holdings, Inc.

BGE and BGE Home Products & Services have agreements to sell on an ongoing basis an undivided interest in a designated pool of customer receivables. Under the agreements, BGE can sell up to a total of $40 million, and BGE Home Products & Services can sell up to a total of $50 million. Under the terms of the agreements, the buyer of the receivables has limited recourse against BGE and has no recourse against BGE Home Products & Services. BGE and BGE Home Products & Services have recorded reserves for credit losses. At December 31, 1999, BGE had sold $28.2 million and BGE Home Products & Services had sold $43.3 million of receivables under these agreements.

#### Guarantees

Constellation Energy has issued guarantees in an amount up to $69.2 million related to credit facilities and contractual performance of certain of its diversified subsidiaries. However, the actual subsidiary liabilities related to these guarantees totaled $21.7 million at December 31, 1999.

BGE guarantees two-thirds of certain debt of Safe Harbor Water Power Corporation. The maximum amount of our guarantee is $23 million. At December 31, 1999, Safe Harbor Water Power Corporation had outstanding debt of $20.4 million, of which $13.6 million is guaranteed by BGE.

At December 31, 1999, our remaining diversified businesses had guaranteed outstanding loans and letters of credit of certain power projects and real estate projects totaling $48.8 million. Our diversified businesses also guarantee certain other borrowings of various power projects and real estate projects.

We assess the risk of loss from these guarantees to be minimal.

**Environmental Matters**

*Clean Air*

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

Title IV primarily addresses emissions of sulfur dioxides. Compliance is required in two phases:

- Phase I became effective January 1, 1995. We met the requirements of this phase by installing flue gas desulfurization systems, switching fuels, and retiring some units.
- Phase II became effective January 1, 2000. We met the compliance requirements through a combination of switching fuels and allowance trading.

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

The Environmental Protection Agency (EPA) issued a final rule in September 1998 that requires up to 85% NOx emissions reduction by 22 states including Maryland and Pennsylvania. While the rule was appealed by several groups including utilities and states, Maryland will meet the requirements of the rule by 2003.

Based on the MDE and EPA regulations, we currently estimate that the additional controls needed at our generating plants to meet the MDE's 65% NOx emission reduction requirements will cost approximately $135 million. Through December 31, 1999, we have spent approximately $51 million to meet the MDE's 65% reduction requirements. We estimate the additional cost for EPA's 85% reduction requirements to be approximately $35 million by 2003.

In July 1997, the EPA published new National Ambient Air Quality Standards for very fine particulates and revised standards for ozone attainment. In 1999, these new standards were successfully challenged in court. The EPA is expected to appeal the 1999 court rulings to the Supreme Court. While these standards may require increased controls at our fossil generating plants in the future, implementation will be delayed for several years. We cannot estimate the cost of these increased controls at this time because the states, including Maryland and Pennsylvania, still need to determine what reductions in pollutants will be necessary to meet the new federal standards.

*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 15.43% 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 $4.9 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.

On July 12, 1999, the EPA notified us, along with nineteen other entities, that we may be a potentially responsible party at the 68th Street Dump/Industrial Enterprises Site, also known as the Robb Tyler Dump located in Baltimore, Maryland. The EPA indicated that it is proceeding with plans to conduct a remedial investigation and feasibility study. This site was proposed for listing as a federal Superfund site in January 1999, but the listing has not been finalized. Although our potential liability cannot be estimated, we do not expect such liability to be material based on our records showing that we did not send waste to the site.

Also, we are coordinating investigation of several sites where gas was manufactured in the past. The investigation of these sites includes reviewing possible actions to remove coal tar. In late December 1996, we signed a consent order with the MDE that requires us to implement remedial action plans for contamination at and around the Spring Gardens site, located in Baltimore, Maryland. We submitted the required remedial action plans and they have been approved by the MDE. Based on the remedial action plans, the costs we consider to be probable to remedy the contamination are estimated to total $47 million in nominal dollars (including inflation). We have recorded these costs as a liability on our Consolidated Balance Sheets and have deferred these costs, net of accumulated amortization and amounts we recovered from insurance companies, as a regulatory asset. We discuss this further in Note 5 on page 61. Through December 31, 1999, we have spent approximately $34 million for remediation at this site.

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

We do not expect the cleanup costs of the remaining sites to have a material effect on our financial results.

**Nuclear Insurance**

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

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

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

***Insurance for Calvert Cliffs and Third Party Claims***

For physical damage to Calvert Cliffs, we have $2.75 billion of property insurance from an industry mutual insurance company. If an outage at either of the two units at Calvert Cliffs is caused by an insured physical damage loss and lasts more than 12 weeks, we have insurance coverage for replacement power costs up to $490.0 million per unit, provided by an industry mutual insurance company. This amount can be reduced by up to $98.0 million per unit if an outage at both units of the plant is caused by a single insured physical damage loss. If accidents at any insured plants cause a shortfall of funds at the industry mutual insurance company, all policyholders could be assessed, with our share being up to $21.7 million.

In addition we, as well as others, could be charged for a portion of any third party claims associated with a nuclear incident at any commercial nuclear power plant in the country. At December 31, 1999, the limit for third party claims from a nuclear incident is $9.34 billion under the provisions of the Price Anderson Act. If third party claims exceed $200 million (the amount of primary insurance), our share of the total liability for third party claims could be up to $176.2 million per incident. That amount would be payable at a rate of $20 million per year.

***Insurance for Worker Radiation Claims***

As an operator of a commercial nuclear power plant in the United States, we are required to purchase insurance to cover radiation injury claims of certain nuclear workers. On January 1, 1998, a new insurance policy became effective for all operators requiring coverage for current operations. Waiving the right to make additional claims under the old policy was a condition for acceptance under the new policy. We describe both the old and new policies below.

- Nuclear worker claims reported on or after January 1, 1998 are covered by a new insurance policy with an annual industry aggregate limit of $200 million for radiation injury claims against all those insured by this policy.
- All nuclear worker claims reported prior to January 1, 1998 are still covered by the old insurance policies. Insureds under the old policies, with no current operations, are not required to purchase the new policy described above, and may still make claims against the old policies for the next eight years. If radiation injury claims under these old policies exceed the policy reserves, all policyholders could be assessed, with our share being up to $6.3 million.

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

**Recoverability of Electric Fuel Costs**

Until July 1, 2000, we will continue to recover our cost of electric fuel as long as the Maryland PSC finds that, among other things, we have kept the productive capacity of our generating plants at a reasonable level. To do this, the Maryland PSC will evaluate the performance of our generating plants, and will determine if we used all reasonable and cost-effective maintenance and operating control procedures.

The Maryland PSC, under the Generating Unit Performance Program, measures annually whether we have maintained the productive capacity of our generating plants at reasonable levels. To do this, the program uses a system-wide generating performance target and an individual performance target for each base load generating unit. In fuel rate hearings, actual generating performance adjusted for planned outages will be compared first to the system-wide target.

If that target is met, it should mean that the requirements of Maryland law have been met. If the system-wide target is not met, each unit's adjusted actual generating performance will be compared to its individual performance target to determine if the requirements of Maryland law have been met and, if not, to determine the basis for possibly imposing a penalty on BGE. Even if we meet these targets, parties to fuel rate hearings may still question whether we used all reasonable and cost-effective procedures to try to prevent an outage. If the Maryland PSC decides we were deficient in some way, the Maryland PSC may not allow us to recover the cost of replacement energy.

The two units at Calvert Cliffs use the cheapest fuel. As a result, the costs of replacement energy associated with outages at these units can be significant. We cannot estimate the amount of replacement energy costs that could be challenged or disallowed in future fuel rate proceedings, but such amounts could be material.

Under the terms of the Restructuring Order, BGE's electric fuel rate clause will be discontinued effective July 1, 2000.

We discuss competition and its impact on BGE's generation business further in Note 4 on page 58. The discontinuance of BGE's electric fuel rate clause is discussed further in Note 1 on page 50.

**California Power Purchase Agreements**

Constellation Power, Inc. and subsidiaries and Constellation Investments, Inc. (whose power projects are managed by Constellation Power) have $301.8 million invested in 14 projects that sell electricity in California under power purchase agreements called "Interim Standard Offer No. 4" agreements. Under these agreements, the projects supply electricity to utility companies at:

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

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

We use the term "transitioned" to describe when the 10-year periods for fixed energy rates have expired for these power generation projects and they began supplying electricity at variable rates. The four remaining projects that have not transitioned will do so by December 2000.

The projects that have already transitioned to variable rates have had lower revenues under variable rates than they did under fixed rates. Once the remaining projects have transitioned to variable rates, we expect the revenues from those projects also to be lower than they are under fixed rates.

We discuss the earnings for these projects in the "Diversified Businesses" section of Management's Discussion and Analysis on page 32.

## Note 11.

### Fair Market 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 used the following methods and assumptions in estimating fair value disclosures for financial instruments:

- Cash and cash equivalents, net accounts receivable, other current assets, certain current liabilities, short-term borrowings, current portions of long-term debt and preference stock, and certain deferred credits and other liabilities: The amounts reported in the Consolidated Balance Sheets approximate fair value.
- Investments and other assets where it was practicable to estimate fair value: The fair value is based on quoted market prices where available.
- Fixed-rate long-term debt, and redeemable preference stock: The fair value is based on quoted market prices where available or by discounting remaining cash flows at current market rates. The carrying amount of variable-rate long-term debt approximates fair value.

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 below:

| *At December 31,* | **1999** | | 1998 | |
|---|---|---|---|---|
| | Carrying Amount | Fair Value | Carrying Amount | Fair Value |
| | *(In millions)* | | | |
| Investments and other assets for which it is: | | | | |
| Practicable to estimate fair value | **$ 313.3** | **$ 313.3** | $ 213.0 | $ 213.0 |
| Not practicable to estimate fair value | **46.7** | **N/A** | 56.5 | N/A |
| Fixed-rate long-term debt | **2,728.9** | **2,637.3** | 2,954.7 | 3,076.6 |
| Redeemable preference stock | – | – | 7.0 | 7.2 |

It was not practicable to estimate the fair value of investments held by our diversified businesses in:

- several financial partnerships that invest in nonpublic debt and equity securities, and
- several partnerships that own solar powered energy production facilities.

This is because the timing and amount of cash flows from these investments are difficult to predict. We report these investments at their original cost in our Consolidated Balance Sheets.

The investments in financial partnerships totaled $35.8 million at December 31, 1999 and $41.9 million at December 31, 1998, representing ownership interests up to 10%. The total assets of all of these partnerships totaled $5.9 billion at December 31, 1998 (which is the latest information available).

The investments in solar powered energy production facility partnerships totaled $10.9 million at December 31, 1999 and 1998, representing ownership interests up to 13%. The total assets of all of these partnerships totaled $31.3 million at December 31, 1998 (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 $16.5 million at December 31, 1999. BGE guaranteed outstanding debt of $13.6 million at December 31, 1999 and $18.0 million at December 31, 1998. Our diversified businesses guaranteed outstanding debt totaling $48.8 million at December 31, 1999 and $59.7 million at December 31, 1998. We do not anticipate that we will need to fund these guarantees.

## Note 12.

### Quarterly Financial Data (Unaudited)

Our quarterly financial information has not been audited but, in management's opinion, includes all adjustments necessary for a fair presentation. Our utility business is seasonal in nature with the peak sales periods generally occurring during the summer and winter months. Accordingly, comparisons among quarters of a year may not represent overall trends and changes in operations.

**1999 Quarterly Data**

| | Revenues | Income From Operations | Earnings Applicable to Common Stock | Earnings Per Share of Common Stock |
|---|---|---|---|---|
| | *(In millions, except per-share amounts)* | | | |
| Quarter Ended | | | | |
| March 31 | **$ 932.3** | **$198.1** | **$ 82.8** | **$0.55** |
| June 30 | **820.0** | **163.9** | **68.0** | **0.45** |
| September 30 | **970.4** | **277.7** | **136.1** | **0.91** |
| December 31 | **1,063.5** | **120.2** | **(26.8)** | **(0.18)** |
| Year Ended | | | | |
| December 31 | **$3,786.2** | **$759.9** | **$260.1** | **$1.74** |

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

Our third quarter results include:

- $7.5 million associated with Hurricane Floyd (see the "Electric Operations and Maintenance Expenses" section of Management's Discussion and Analysis),
- a $37.5 million deferral of revenues collected associated with the deregulation of our electric generation business (see Note 5),
- a $17.3 million after-tax write-down of a financial investment (see Note 3),
- a $6.7 million after-tax write-off of a power project (see Note 3), and
- a $3.4 million after-tax write-down of certain senior-living facilities (see Note 2).

Our fourth quarter results include:

- a $66.3 million extraordinary charge associated with the Restructuring Order (see Note 4),
- the recognition of the $37.5 million of revenues that were deferred in the third quarter (see above),
- $75 million in amortization expense for the reduction of our generation plants associated with the Restructuring Order (see the "Electric Depreciation and Amortization Expense" section of Management's Discussion and Analysis),
- a $4.9 million after-tax gain on a financial investment (see Note 3),
- $12.0 million after-tax write-downs of certain power projects (see Note 3), and
- a $2.4 million after-tax write-down of certain senior-living facilities (see Note 2).

**1998 Quarterly Data**

| | Revenues | Income From Operations | Earnings Applicable to Common Stock | Earnings Per Share of Common Stock |
|---|---|---|---|---|
| | *(In millions, except per-share amounts)* | | | |
| Quarter Ended | | | | |
| March 31 | $ 866.1 | $ 183.4 | $ 74.4 | $0.50 |
| June 30 | 767.6 | 156.2 | 57.4 | 0.39 |
| September 30 | 934.0 | 320.4 | 160.9 | 1.08 |
| December 31 | 790.4 | 81.1 | 13.2 | 0.09 |
| Year Ended | | | | |
| December 31 | $3,358.1 | $741.1 | $305.9 | $2.06 |

Our third quarter results include a $10.4 million after-tax gain for earnings in a partnership (see Note 3).

Our fourth quarter results include:

- a $15.4 million after-tax write-off of a real estate investment (see Note 3), and
- a $5.5 million after-tax write-off of an energy services investment (see the "Other Energy Services" section of Management's Discussion and Analysis).

*The sum of the quarterly earnings per share amounts may not equal the total for the year due to the effects of rounding.*

# Constellation Energy Group Board of Directors*

**Christian H. Poindexter**
*Chairman, President and Chief Executive Officer, Constellation Energy Group*
Age 61
BGE Director since 1988
Elected April 1999

**H. Furlong Baldwin**
*Chairman, President and Chief Executive Officer, Mercantile Bankshares Corporation*
Age 68
BGE Director from 1988–1999
Elected April 1999

**Douglas L. Becker**
*President and Co-Chief Executive Officer, Sylvan Learning Systems, Inc.*
Age 34
BGE Director from 1998–1999
Elected April 1999

**James T. Brady**
*Former Secretary, Maryland Department of Business and Economic Development*
Age 59
Constellation Enterprises Director from 1998–1999
Elected May 1999

**Beverly B. Byron**
*Former Congresswoman, U.S. House of Representatives*
Age 67
BGE Director from 1993–1999
Elected April 1999

**J. Owen Cole**
*Director, AllFirst Financial, Inc. and AllFirst Bank*
Age 70
BGE Director from 1977–1999
Elected April 1999

**Dan A. Colussy**
*Former Chairman, President and Chief Executive Officer, UNC Incorporated*
Age 68
BGE Director from 1992–1999
Elected April 1999

**Edward A. Crooke**
*Former Vice Chairman, Constellation Energy Group; Former Chairman, President, and Chief Executive Officer, Constellation Enterprises, Inc.*
Age 61
BGE Director from 1988–1999
Elected April 1999

**James R. Curtiss, Esq.**
*Partner, Winston & Strawn*
Age 46
BGE Director from 1994–1999
Elected April 1999

**Roger W. Gale**
*President and Chief Executive Officer, PHB Hagler Bailly*
Age 53
Constellation Enterprises Director from 1998–1999
Elected May 1999

**Jerome W. Geckle**
*Retired Chairman, PHH Corporation*
Age 70
BGE Director from 1980–1999
Elected April 1999

**Dr. Freeman A. Hrabowski, III**
*President, University of Maryland Baltimore County*
Age 49
BGE Director from 1994–1999
Elected April 1999

**Nancy Lampton**
*Chairman and Chief Executive Officer, American Life and Accident Insurance Company of Kentucky*
Age 57
BGE Director from 1994–1999
Elected April 1999

**Charles R. Larson**
*Admiral, United States Navy (Retired)*
Age 63
BGE Director from 1998–1999
Elected April 1999

**George V. McGowan †**
*Former Chairman and Chief Executive Officer, BGE*
Age 72
BGE Director from 1980–1999
Elected April 1999

**George L. Russell, Jr., Esq.**
*Attorney at Law, Law Offices of Peter G. Angelos*
Age 70
BGE Director from 1988–1999
Elected April 1999

**Mayo A. Shattuck, III**
*Co-Chairman and Co-Chief Executive Officer, DB Alex. Brown, LLC and Deutsche Banc Securities, Inc.*
Age 45
Constellation Enterprises Director from 1998–1999
Elected May 1999

**Michael D. Sullivan**
*Chairman, Golf America Stores, Inc.*
Age 60
BGE Director from 1992–1999
Elected April 1999

## Committees of the Board

**Audit Committee**
J. Owen Cole, Chairman
Douglas L. Becker
James T. Brady
George L. Russell, Jr.

**Committee on Management**
Jerome W. Geckle, Chairman
J. Owen Cole
Dan A. Colussy
Mayo A. Shattuck, III
Michael D. Sullivan

**Committee on Nuclear Power**
James R. Curtiss, Chairman
Beverly B. Byron
Charles R. Larson
George V. McGowan

**Executive Committee**
George V. McGowan, Chairman
H. Furlong Baldwin
James T. Brady
Edward A. Crooke
Dr. Freeman A. Hrabowski, III
Christian H. Poindexter
George L. Russell, Jr.

**Long-Range Strategy Committee**
H. Furlong Baldwin, Chairman
Douglas L. Becker
Dan A. Colussy
Edward A. Crooke
James R. Curtiss
Roger W. Gale
Jerome W. Geckle
Nancy Lampton
Charles R. Larson
Mayo A. Shattuck, III
Michael D. Sullivan

**Committee on Workplace Diversity**
Beverly B. Byron, Chairman
Roger W. Gale
Dr. Freeman A. Hrabowski, III
Nancy Lampton

## Constellation Energy Group Officers

**Christian H. Poindexter**
*Chairman, President and Chief Executive Officer*
Age 61

**Thomas F. Brady**
*Vice President, Corporate Strategy & Development*
Age 50

**David A. Brune**
*Vice President, Finance & Accounting, Chief Financial Officer and Secretary*
Age 59

**Robert S. Fleishman**
*Vice President, Corporate Affairs and General Counsel*
Age 46

**Linda D. Miller**
*Vice President, Human Resources*
Age 49

**Richard M. Bange, Jr.**
*Controller and Assistant Secretary*
Age 55

**Thomas E. Ruszin, Jr.**
*Treasurer and Assistant Secretary*
Age 45

## Business Unit Leaders

**Frank O. Heintz**
*President-Elect*
*Baltimore Gas and Electric Co.*
Age 55

**Charles W. Shivery**
*President*
*Constellation Power Source, Inc.*
Age 54

**Robert E. Denton**
*President*
*Constellation Nuclear Group, LLC*
Age 57

**John F. Walter**
*President*
*Constellation Power, Inc.*
Age 65

**William H. Munn**
*President*
*BGE Home Products & Services, Inc.*
Age 52

**Steven D. Kesler**
*President*
*Constellation Real Estate Group, Inc.*
*Constellation Investments, Inc.*
Age 48

**Gregory S. Jarosinski**
*President*
*Constellation Energy Source, Inc.*
Age 47

* The Board is divided into three classes with one class of directors elected at each annual shareholder meeting for a three-year term.

† George V. McGowan will retire from the Board in April 2000.

## Five-Year Statistical Summary

| | **1999** | 1998 | 1997 | 1996 | 1995 |
|---|---|---|---|---|---|
| **Common Stock Data** | | | | | |
| ***Quarterly Earnings Per Share*** | | | | | |
| First Quarter | **$0.55** | $0.50 | $0.43 | $0.62 | $0.41 |
| Second Quarter | **0.45** | 0.39 | 0.05 | 0.36 | 0.28 |
| Third Quarter | **0.91** | 1.08 | 1.11 | 0.93 | 1.04 |
| Fourth Quarter | **(0.18)** | 0.09 | 0.12 | (0.06) | 0.29 |
| Total | **$1.74** | $2.06 | $1.72 | $1.85 | $2.02 |
| ***Earnings Per Share Before Nonrecurring Charges Included in Operations*** | **$2.48** | $2.20 | $2.28 | $2.27 | $2.02 |
| ***Dividends*** | | | | | |
| Dividends Declared Per Share | **$1.68** | $1.67 | $1.63 | $1.59 | $1.55 |
| Dividends Paid Per Share | **1.68** | 1.66 | 1.62 | 1.58 | 1.54 |
| Dividend Payout Ratio | | | | | |
| Reported | **96.6%** | 81.1% | 94.8% | 85.9% | 76.7% |
| Excluding nonrecurring charges to earnings | **67.7%** | 75.9% | 71.5% | 70.0% | 76.7% |
| ***Market Prices*** | | | | | |
| High | **$ 31 1/2** | $ 35 1/4 | $ 34 5/16 | $ 29 1/2 | $ 29 |
| Low | **24 11/16** | 29 1/4 | 24 3/4 | 25 | 22 |
| Close | **29** | 30 7/8 | 34 1/8 | 26 3/4 | 28 1/2 |
| **Capital Structure** | | | | | |
| ***Consolidated*** | | | | | |
| Long-Term Debt | **48.8%** | 53.5% | 48.0% | 45.0% | 42.8% |
| Short-Term Borrowings | **5.4** | — | 4.7 | 5.1 | 4.4 |
| BGE Preferred and Preference Stock | **2.7** | 2.9 | 4.8 | 6.5 | 8.5 |
| Common Shareholders' Equity | **43.1** | 43.6 | 42.5 | 43.4 | 44.3 |
| ***Utility Only*** | | | | | |
| Long-Term Debt | **50.9%** | 51.5% | 45.4% | 42.5% | 40.4% |
| Short-Term Borrowings | **2.4** | — | 5.8 | 6.1 | 5.2 |
| BGE Preferred and Preference Stock | **3.5** | 3.6 | 5.9 | 7.8 | 10.0 |
| Common Shareholders' Equity | **43.2** | 44.9 | 42.9 | 43.6 | 44.4 |

*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 12 to the Consolidated Financial Statements.*

**Common Stock Dividends* and Price Ranges**

| | 1999 | | | 1998 | | |
|---|---|---|---|---|---|---|
| | Dividend Declared | Price | | Dividend Declared | Price | |
| | | High | Low | | High | Low |
| First Quarter | $ .42 | $31 1/8 | $24 11/16 | $ .41 | $34 1/8 | $29 3/4 |
| Second Quarter | .42 | 31 3/8 | 25 1/8 | .42 | 32 15/16 | 29 1/4 |
| Third Quarter | .42 | 30 7/8 | 27 3/16 | .42 | 33 5/8 | 29 5/16 |
| Fourth Quarter | .42 | 31 1/2 | 27 1/2 | .42 | 35 1/4 | 30 1/8 |
| Total | $1.68 | | | $1.67 | | |

**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.

**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, 1999, there were 66,093 common shareholders of record.

**Annual Meeting**

The annual meeting of shareholders will be held at 10 a.m. on Friday, April 28, 2000, in the 2nd floor Conference Room of the Gas and Electric Building, located at 39 W. Lexington St., 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 David A. Brune, Chief Financial Officer and Secretary, Vice President, Finance & Accounting, 20th Floor, 250 W. Pratt St., Baltimore, Maryland 21201.

**Auditors**

PricewaterhouseCoopers LLP

* *Dividends paid prior to April 30, 1999 were on BGE common stock. As a result of the common stock share exchange, Constellation Energy is the successor to BGE.*

**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:
Harris Trust and Savings Bank
Chicago, Illinois

**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 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 820
39 W. Lexington Street
Baltimore, MD 21201

250 W. Pratt Street
Baltimore, Maryland 21201

www.constellationenergy.com

# EXHIBIT II

# QUARTERLY FINANCIAL STATEMENTS

# AS OF JUNE 30, 2000

**Baltimore Gas and Electric Company**
**Calvert Cliffs Nuclear Power Plant**
**August 15, 2000**

**Constellation Energy Group**

# Quarterly Financial Summary

## June 2000

*Baltimore Gas and Electric Company*
*BGE Home Products and Services*
*Constellation Energy Source*
*Constellation Investments*
*Constellation Nuclear*
*Constellation Power*
*Constellation Power Source*
*Constellation Real Estate Group*

## Consolidated Statements of Income (Unaudited)

| | Three Months Ended June 30, 2000 | Three Months Ended June 30, 1999 | Six Months Ended June 30, 2000 | Six Months Ended June 30, 1999 | Twelve Months Ended June 30, 2000 | Twelve Months Ended June 30, 1999 |
|---|---|---|---|---|---|---|
| | *(In Millions, Except Per Share Amounts)* | | | | | |
| **Revenues** | | | | | | |
| Electric | $ 565.3 | $ 533.0 | $1,089.7 | $1,046.0 | $2,302.5 | $2,240.9 |
| Gas | 91.6 | 79.9 | 286.1 | 272.7 | 489.9 | 459.5 |
| Nonregulated | 211.5 | 245.6 | 484.8 | 523.2 | 1,102.0 | 865.9 |
| Total revenues | 868.4 | 858.5 | 1,860.6 | 1,841.9 | 3,894.4 | 3,566.3 |
| **Operating Expenses** | | | | | | |
| Electric fuel and purchased energy | 119.5 | 120.0 | 238.1 | 241.2 | 464.7 | 504.8 |
| Gas purchased for resale | 40.8 | 33.0 | 143.7 | 135.1 | 239.2 | 213.3 |
| Operations | 138.9 | 135.2 | 273.2 | 270.5 | 548.6 | 558.8 |
| Maintenance | 54.4 | 53.6 | 99.5 | 102.4 | 183.3 | 187.8 |
| Nonregulated—selling, general, and administrative | 199.2 | 210.2 | 414.1 | 437.6 | 984.8 | 741.2 |
| Depreciation and amortization | 130.6 | 90.8 | 263.1 | 181.1 | 531.8 | 372.1 |
| Taxes other than income taxes | 51.1 | 51.8 | 112.3 | 112.1 | 227.4 | 224.9 |
| Total operating expenses | 734.5 | 694.6 | 1,544.0 | 1,480.0 | 3,179.8 | 2,802.9 |
| **Income from operations** | 133.9 | 163.9 | 316.6 | 361.9 | 714.6 | 763.4 |
| **Other Income** | 1.0 | 5.2 | 6.0 | 4.5 | 9.5 | 7.4 |
| **Income Before Fixed Charges and Income Taxes** | 134.9 | 169.1 | 322.6 | 366.4 | 724.1 | 770.8 |
| **Fixed Charges** | | | | | | |
| Interest expense (net) | 65.1 | 58.2 | 125.4 | 119.3 | 247.6 | 241.8 |
| BGE preference stock dividends | 3.3 | 3.4 | 6.6 | 6.9 | 13.3 | 17.1 |
| Total fixed charges | 68.4 | 61.6 | 132.0 | 126.2 | 260.9 | 258.9 |
| **Income Before Income Taxes** | 66.5 | 107.5 | 190.6 | 240.2 | 463.2 | 511.9 |
| **Income Taxes** | | | | | | |
| Current | 45.6 | 26.4 | 106.8 | 75.9 | 212.9 | 157.4 |
| Deferred | (16.6) | 15.3 | (23.7) | 17.8 | (28.5) | 39.1 |
| Investment tax credit adjustments | (2.1) | (2.2) | (4.2) | (4.3) | (8.5) | (9.5) |
| Total income taxes | 26.9 | 39.5 | 78.9 | 89.4 | 175.9 | 187.0 |
| **Income Before Extraordinary Item** | 39.6 | 68.0 | 111.7 | 150.8 | 287.3 | 324.9 |
| **Extraordinary Loss, Net of Taxes of $30.4** | — | — | — | — | (66.3) | — |
| **Net Income** | $ 39.6 | $ 68.0 | $ 111.7 | $ 150.8 | $ 221.0 | $ 324.9 |
| **Earnings Applicable to Common Stock** | $ 39.6 | $ 68.0 | $ 111.7 | $ 150.8 | $ 221.0 | $ 324.9 |
| Average Shares of Common Stock Outstanding | 149.7 | 149.6 | 149.6 | 149.6 | 149.6 | 149.2 |
| **EARNINGS PER COMMON SHARE** | | | | | | |
| Regulated electric business | $0.32 | $0.37 | $0.55 | $0.67 | $1.67 | $1.79 |
| Regulated gas business | 0.02 | — | 0.15 | 0.15 | 0.22 | 0.21 |
| Total utility business | 0.34 | 0.37 | 0.70 | 0.82 | 1.89 | 2.00 |
| Domestic wholesale energy business: | | | | | | |
| Wholesale power marketing | 0.05 | 0.08 | 0.14 | 0.13 | 0.24 | 0.17 |
| Domestic power projects | 0.05 | 0.03 | 0.09 | 0.08 | 0.25 | 0.27 |
| Total domestic wholesale energy business | 0.10 | 0.11 | 0.23 | 0.21 | 0.49 | 0.44 |
| Other | (0.07) | (0.01) | (0.05) | — | (0.05) | (0.10) |
| Total earnings per share before nonrecurring items | 0.37 | 0.47 | 0.88 | 1.03 | 2.33 | 2.34 |
| Deregulation transition cost* | (0.10) | — | (0.10) | — | (0.10) | — |
| Hurricane Floyd expense* | — | — | — | — | (0.03) | — |
| Net write-downs of financial investment* | — | (0.02) | — | (0.02) | (0.09) | (0.02) |
| Voluntary early retirement program* | (0.01) | — | (0.03) | — | (0.03) | — |
| Write-downs of power projects* | — | — | — | — | (0.12) | — |
| Write-downs of real estate investments* | — | — | — | — | (0.04) | (0.10) |
| Write-off of energy services investment* | — | — | — | — | — | (0.04) |
| Earnings Per Share of Common Stock and Earnings Per Share of Common Stock—Assuming Dilution Before Extraordinary Item | 0.26 | 0.45 | 0.75 | 1.01 | 1.92 | 2.18 |
| Extraordinary item, net of income taxes | — | — | — | — | (0.44) | — |
| Earnings Per Share of Common Stock and Earnings Per Share of Common Stock—Assuming Dilution | $0.26 | $0.45 | $0.75 | $1.01 | $1.48 | $2.18 |
| Investment in utility business at end of period | $2,324.1 | $2,371.4 | $2,324.1 | $2,371.4 | $2,324.1 | $2,371.4 |
| Investment in nonregulated businesses at end of period | $ 679.7 | $ 631.8 | $ 679.7 | $ 631.8 | $ 679.7 | $ 631.8 |

*Certain prior-period amounts have been reclassified to conform with the current period's presentation.*
**Nonrecurring items included in earnings from operations.*

## Consolidated Statements Of Cash Flows (Unaudited)

| | Six Months Ended June 30, 2000 | Six Months Ended June 30, 1999 | Twelve Months Ended June 30, 2000 | Twelve Months Ended June 30, 1999 |
|---|---|---|---|---|
| | (In Millions) | | | |
| **Cash Flows From Operating Activities** | | | | |
| Net income | $ 111.7 | $ 150.8 | $ 221.0 | $ 324.9 |
| Adjustments to reconcile to net cash provided by operating activities | | | | |
| Extraordinary loss | — | — | 66.3 | — |
| Depreciation and amortization | 288.2 | 208.4 | 585.7 | 428.7 |
| Deferred income taxes | (23.7) | 17.8 | (28.5) | 39.1 |
| Investment tax credit adjustments | (4.2) | (4.3) | (8.5) | (9.5) |
| Deferred fuel costs | 9.8 | 7.1 | (58.5) | (21.6) |
| Accrued pension and postemployment benefits | 12.1 | 28.7 | 19.1 | 59.7 |
| Gain on sale of subsidiaries | (13.3) | — | (13.3) | — |
| Write-downs of real estate investments | — | — | 8.3 | 26.2 |
| Write-down of financial investment | — | 5.5 | 20.7 | 5.5 |
| Write-downs of power projects | — | — | 28.5 | — |
| Equity in earnings of affiliates and joint ventures (net) | 5.3 | 26.2 | (11.0) | (16.5) |
| Changes in assets from energy trading activities | (767.2) | (141.2) | (805.1) | 77.1 |
| Changes in liabilities from energy trading activities | 671.0 | 37.4 | 698.4 | (196.7) |
| Changes in other current assets | 59.8 | (45.3) | (123.8) | (121.3) |
| Changes in other current liabilities | (1.3) | 89.3 | 44.6 | 170.7 |
| Other | (5.9) | (10.2) | 27.3 | — |
| Net cash provided by operating activities | 342.3 | 370.2 | 671.2 | 766.3 |
| **Cash Flows From Investing Activities** | | | | |
| Utility construction and other capital expenditures | (218.1) | (186.0) | (468.2) | (412.1) |
| Contributions to nuclear decommissioning trust fund | (8.8) | (8.8) | (17.6) | (17.6) |
| Purchases of marketable equity securities | (2.4) | (12.4) | (15.0) | (29.2) |
| Sales of marketable equity securities | 14.4 | 9.8 | 39.5 | 24.0 |
| Other financial investments | 8.7 | 8.5 | 11.5 | 4.9 |
| Real estate projects and investments | 9.0 | 40.7 | 17.6 | 35.3 |
| Power projects | (147.0) | (31.8) | (194.0) | (115.9) |
| Investment in Orion Power Holdings, Inc. | (101.5) | — | (198.3) | — |
| Other | (12.4) | (15.5) | (52.9) | (64.9) |
| Net cash used in investing activities | (458.1) | (195.5) | (877.4) | (575.5) |
| **Cash Flow From Financing Activities** | | | | |
| Proceeds from issuance of | | | | |
| Short-term borrowings | 4,852.6 | 1,029.3 | 8,671.5 | 1,515.4 |
| Long-term debt | 800.1 | 127.5 | 975.5 | 567.4 |
| Common stock | 6.0 | 9.6 | 6.0 | 39.1 |
| Repayments of short-term borrowings | (5,009.3) | (920.0) | (8,566.0) | (1,478.6) |
| Reacquisitions of long-term debt | (347.7) | (360.5) | (571.7) | (656.6) |
| Redemptions of BGE preference stock | — | — | (7.0) | (124.9) |
| Common stock dividends paid | (125.6) | (125.5) | (251.3) | (250.4) |
| Other | (6.6) | (5.4) | (7.8) | (1.3) |
| Net cash provided by (used in) financing activities | 169.5 | (245.0) | 249.2 | (389.9) |
| Net Increase (Decrease) in Cash and Cash Equivalents | 53.7 | (70.3) | 43.0 | (199.1) |
| Cash and Cash Equivalents at Beginning of Period | 92.7 | 173.7 | 103.4 | 302.5 |
| Cash and Cash Equivalents at End of Period | $ 146.4 | $ 103.4 | $ 146.4 | $ 103.4 |
| **Other Cash Flow Information** | | | | |
| Interest paid (net of amounts capitalized) | $ 131.5 | $ 120.4 | $ 256.4 | $ 242.4 |
| Income taxes paid | $ 110.9 | $ 101.0 | $ 175.5 | $ 175.4 |

*Certain prior period amounts have been reclassified to conform with the current period's presentation.*

## Utility Operating Statistics

| ELECTRIC | Three Months Ended June 30, 2000 | 1999 | Six Months Ended June 30, 2000 | 1999 | Twelve Months Ended June 30, 2000 | 1999 |
|---|---|---|---|---|---|---|
| **Revenues** *(In Millions)* | | | | | | |
| Residential—with househeating | $ 84.8 | $ 84.1 | $ 203.8 | $ 203.6 | $ 400.1 | $ 402.5 |
| —other | 147.1 | 131.0 | 274.1 | 250.7 | 598.8 | 560.3 |
| —total | 231.9 | 215.1 | 477.9 | 454.3 | 998.9 | 962.8 |
| Commercial | 243.4 | 225.0 | 448.9 | 423.5 | 964.7 | 922.2 |
| Industrial | 50.3 | 51.6 | 93.1 | 96.5 | 200.9 | 207.5 |
| System Sales | 525.6 | 491.7 | 1,019.9 | 974.3 | 2,164.5 | 2,092.5 |
| Interchange and Other Sales | 30.9 | 34.9 | 53.8 | 59.3 | 106.5 | 122.3 |
| Other | 8.9 | 6.5 | 16.3 | 12.9 | 32.5 | 28.1 |
| Total | $ 565.4 | $ 533.1 | $1,090.0 | $1,046.5 | $2,303.5 | $2,242.9 |
| **Sales** *(In Thousands)* —MWH | | | | | | |
| Residential—with househeating | 997 | 989 | 2,668 | 2,663 | 5,008 | 5,034 |
| —other | 1,582 | 1,388 | 3,112 | 2,820 | 6,637 | 6,180 |
| —total | 2,579 | 2,377 | 5,780 | 5,483 | 11,645 | 11,214 |
| Commercial | 3,468 | 3,198 | 6,856 | 6,468 | 13,953 | 13,357 |
| Industrial | 1,106 | 1,091 | 2,188 | 2,194 | 4,344 | 4,468 |
| System Sales | 7,153 | 6,666 | 14,824 | 14,145 | 29,942 | 29,039 |
| Interchange and Other Sales | 1,189 | 1,441 | 2,064 | 2,659 | 4,191 | 5,315 |
| Total | 8,342 | 8,107 | 16,888 | 16,804 | 34,133 | 34,354 |
| **GAS** | | | | | | |
| **Revenues** *(In Millions)* | | | | | | |
| Residential —excluding delivery service | $ 51.3 | $ 51.1 | $ 161.3 | $ 175.9 | $ 283.4 | $ 291.1 |
| —delivery service | 3.3 | 1.8 | 12.6 | 6.7 | 17.4 | 9.7 |
| —total | 54.6 | 52.9 | 173.9 | 182.6 | 300.8 | 300.8 |
| Commercial—excluding delivery service | 13.2 | 12.9 | 48.3 | 49.4 | 78.2 | 80.2 |
| —delivery service | 5.3 | 4.3 | 14.3 | 13.5 | 25.2 | 22.2 |
| Industrial —excluding delivery service | 0.9 | 1.1 | 4.4 | 4.7 | 7.9 | 9.1 |
| —delivery service | 3.8 | 3.5 | 8.0 | 8.1 | 16.0 | 15.9 |
| System Sales | 77.8 | 74.7 | 248.9 | 258.3 | 428.1 | 428.2 |
| Off-System Sales | 12.7 | 5.5 | 34.7 | 15.1 | 62.6 | 30.3 |
| Other | 2.2 | 2.1 | 4.1 | 3.8 | 8.0 | 7.3 |
| Total | $ 92.7 | $ 82.3 | $ 287.7 | $ 277.2 | $ 498.7 | $ 465.8 |
| **Sales** *(In Thousands)* —DTH | | | | | | |
| Residential —excluding delivery service | 4,597 | 5,148 | 19,052 | 21,460 | 31,864 | 34,143 |
| —delivery service | 1,258 | 554 | 5,125 | 2,403 | 7,189 | 3,575 |
| —total | 5,855 | 5,702 | 24,177 | 23,863 | 39,053 | 37,718 |
| Commercial—excluding delivery service | 1,689 | 1,657 | 7,299 | 7,455 | 11,578 | 12,065 |
| —delivery service | 4,366 | 3,977 | 12,400 | 11,278 | 21,409 | 18,596 |
| Industrial —excluding delivery service | (20) | 101 | 515 | 782 | 1,100 | 1,676 |
| —delivery service | 8,473 | 7,369 | 17,226 | 16,192 | 34,152 | 33,810 |
| System Sales | 20,363 | 18,806 | 61,617 | 59,570 | 107,292 | 103,865 |
| Off-System Sales | 3,475 | 2,263 | 10,235 | 6,382 | 19,396 | 12,502 |
| Total | 23,838 | 21,069 | 71,852 | 65,952 | 126,688 | 116,367 |

*Utility operating statistics do not reflect the elimination of intercompany transactions.*

### Heating/Cooling Degree Days (Calendar—Month Basis)

| | | | | | | |
|---|---|---|---|---|---|---|
| Heating degree days—Actual | 512 | 517 | 2,817 | 2,907 | 4,495 | 4,541 |
| —Normal | 534 | 531 | 3,008 | 2,987 | 4,775 | 4,759 |
| Cooling degree days—Actual | 263 | 203 | 268 | 204 | 910 | 839 |
| —Normal | 227 | 230 | 231 | 233 | 840 | 840 |

### Utility Electric Generation Statistics

*Twelve Months Ended June 30,*

| | Nuclear | Coal | Oil | Hydro & Gas | Purchased Power Net of Energy Sales | Total |
|---|---|---|---|---|---|---|
| Generation by Fuel Type (%) | | | | | | |
| 2000 | 42.5 | 56.5 | 1.9 | 3.5 | (4.4) | 100.0 |
| 1999 | 43.3 | 57.3 | 4.3 | 3.0 | (7.9) | 100.0 |
| Thousands of MWH | | | | | | |
| 2000 | 13,516 | 17,957 | 613 | 1,124 | (1,401) | 31,809 |
| 1999 | 13,312 | 17,642 | 1,330 | 922 | (2,431) | 30,775 |
| Average Cost of Fuel (Cents per Million Btu) | | | | | | *All Fuels* |
| 2000 | 43.46 | 138.19 | 307.05 | — | — | 101.02 |
| 1999 | 45.52 | 137.53 | 214.42 | — | — | 101.65 |

## Consolidated Balance Sheets (Unaudited)

| | June 30, 2000 | June 30, 1999 |
|---|---|---|
| | (In Millions) | |
| **ASSETS** | | |
| **Current Assets** | | |
| Cash and cash equivalents | $ 146.4 | $ 103.4 |
| Accounts receivable (net of allowance for uncollectibles of $27.9 and $36.6, respectively) | 559.7 | 503.0 |
| Trading securities | 156.8 | 109.4 |
| Assets from energy trading activities | 1,079.3 | 274.2 |
| Fuel stocks | 84.7 | 69.1 |
| Materials and supplies | 138.2 | 149.5 |
| Prepaid taxes other than income taxes | 8.8 | 3.5 |
| Other | 62.3 | 57.0 |
| Total current assets | 2,236.2 | 1,269.1 |
| **Investments And Other Assets** | | |
| Real estate projects and investments | 298.9 | 319.2 |
| Power projects | 926.2 | 755.8 |
| Financial investments | 167.8 | 172.6 |
| Nuclear decommissioning trust fund | 230.3 | 199.2 |
| Net pension asset | 99.3 | 96.6 |
| Other | 533.4 | 262.1 |
| Total investments and other assets | 2,255.9 | 1,805.5 |
| **Utility Plant** | | |
| Utility plant | 9,131.7 | 8,838.6 |
| Accumulated depreciation | (3,572.2) | (3,193.5) |
| Net utility plant | 5,559.5 | 5,645.1 |
| **Deferred Charges** | | |
| Regulatory assets (net) | 522.9 | 519.8 |
| Other | 61.9 | 58.2 |
| Total deferred charges | 584.8 | 578.0 |
| **Total Assets** | $10,636.4 | $9,297.7 |
| **LIABILITIES AND CAPITALIZATION** | | |
| **Current Liabilities** | | |
| Short-term borrowings | $ 214.8 | $ 109.3 |
| Current portions of long-term debt and preference stock | 883.5 | 474.3 |
| Accounts payable | 301.7 | 338.3 |
| Customer deposits | 43.0 | 38.3 |
| Liabilities from energy trading activities | 834.8 | 136.4 |
| Dividends declared | 66.2 | 66.3 |
| Accrued taxes | 37.3 | 3.0 |
| Accrued interest | 59.6 | 55.9 |
| Accrued vacation costs | 36.6 | 36.3 |
| Other | 50.6 | 35.1 |
| Total current liabilities | 2,528.1 | 1,293.2 |
| **Deferred Credits And Other Liabilities** | | |
| Deferred income taxes | 1,275.5 | 1,314.3 |
| Postretirement and postemployment benefits | 254.9 | 231.9 |
| Deferred investment tax credits | 105.4 | 113.7 |
| Decommissioning of federal uranium enrichment facilities | 27.2 | 30.8 |
| Other | 291.0 | 155.7 |
| Total deferred credits and other liabilities | 1,954.0 | 1,846.4 |
| **Long-Term Debt** | | |
| First refunding mortgage bonds of BGE | 1,321.7 | 1,429.2 |
| Other long-term debt of BGE | 1,028.4 | 1,000.8 |
| Company obligated mandatorily redeemable trust preferred securities of subsidiary trust holding solely 7.16% debentures of BGE | 250.0 | 250.0 |
| Long-term debt of nonregulated businesses | 1,246.6 | 762.6 |
| Unamortized discount and premium | (9.8) | (11.6) |
| Current portion of long-term debt | (883.5) | (467.3) |
| Total long-term debt | 2,953.4 | 2,963.7 |
| **BGE Redeemable Preference Stock** | — | 7.0 |
| Current portion of redeemable preference stock | — | (7.0) |
| Total BGE redeemable preference stock | — | — |
| **BGE Preference Stock Not Subject To Mandatory Redemption** | 190.0 | 190.0 |
| **Common Shareholders' Equity** | | |
| Common stock | 1,501.8 | 1,494.3 |
| Retained earnings | 1,485.1 | 1,515.5 |
| Accumulated other comprehensive income (loss) | 24.0 | (5.4) |
| Total common shareholders' equity | 3,010.9 | 3,004.4 |
| Total capitalization | 6,154.3 | 6,158.1 |
| **Total Liabilities And Capitalization** | $10,636.4 | $9,297.7 |

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

## Supplemental Financial Statistics

| | Twelve Months Ended June 30, | | | |
|---|---|---|---|---|
| | Utility | | Consolidated | |
| | 2000 | 1999 | 2000 | 1999 |
| **Capitalization*** | | | | |
| Long-term debt | 44.4% | 45.5% | 49.5% | 47.2% |
| Company obligated manditorily redeemable trust preferred securities of BGE | 4.7% | 4.7% | 3.4% | 3.7% |
| Short-term borrowings | 3.8% | 2.1% | 3.0% | 1.6% |
| BGE Preference stock | 3.6% | 3.7% | 2.6% | 2.9% |
| Common equity | 43.5% | 44.0% | 41.5% | 44.6% |
| **Return on Average Common Equity** | | | | |
| Reported | 8.8% | 12.5% | 7.3% | 10.9% |
| Excluding nonrecurring items included in earnings from operations** | 11.9% | 12.5% | 11.7% | 11.6% |
| **Ratio of Earnings (SEC Method)** | | | | |
| To fixed charges | 3.40 | 3.32 | 2.61 | 2.75 |
| To fixed charges and preference dividends combined | 3.06 | 2.94 | 2.61 | 2.75 |
| **AFC as a % of Earnings Applicable to Common Stock** | 3.1% | 3.7% | 2.9% | 3.2% |
| **Effective Tax Rate** | 36.4% | 34.7% | 36.9% | 35.4% |

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

**Capitalization includes current portions of long-term debt and BGE preference stock.*

***Nonrecurring items included in earnings from operations are shown on the Consolidated Statements of Income.*

## Common Stock Data

| | Three Months Ended June 30, | | Twelve Months Ended June 30, | |
|---|---|---|---|---|
| | 2000 | 1999 | 2000 | 1999 |
| **Common Stock Dividends—Per Share** | | | | |
| —Declared | $0.42 | $0.42 | $1.68 | $1.68 |
| —Paid | $0.42 | $0.42 | $1.68 | $1.68 |
| **Market Value—Per Share** | | | | |
| —High | $35 11/16 | $31 3/8 | $35 11/16 | $35 1/4 |
| —Low | $31 1/4 | $25 1/8 | $27 1/16 | $24 11/16 |
| —Close | $32 9/16 | $29 5/8 | $32 9/16 | $29 5/8 |
| Shares Outstanding—End of Period *(In Millions)* | 149.7 | 149.6 | 149.7 | 149.6 |
| Book Value per Share—End of Period | $20.11 | $20.09 | $20.11 | $20.09 |

*Inquiries concerning this summary should be directed to:*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*Vice President,*
*Chief Financial Officer,*
*and Secretary*
*410-234-5000*

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*Constellation Energy Group*
*P.O. Box 1475*
*Baltimore, Maryland 21203*





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## EXHIBIT III

# PROJECTED CASH FLOW FOR 12 MONTHS

# ENDED JULY 31, 2001

# Internal Cash Flow Projection
## For Calvert Cliffs Nuclear Power Plant

| | | |
|---|---|---|
| Percentage Ownership in all Operating Nuclear Units | Calvert Cliffs Unit No. 1 | 100.00% |
| | Calvert Cliffs Unit No. 2 | 100.00% |

| | |
|---|---|
| Maximum Total Contingent Liability (000) per Nuclear Incident | $176,200 |
| Payable at Per Year (000) | $20,000 |

| | Actual Twelve Months Ended 6/30/00 | Projected Twelve Months Ended 7/31/01 |
|---|---|---|
| Non - Cash Expenses ($000) | | |
| Depreciation and Amortization | $548,385 | $437,538 |
| Deferred Income Taxes and Investment Tax Credits | (44,619) | 3,822 |
| Total | $503,766 | $441,360 |
| Percentage of Total to Maximum Total Contingent Liability Payable Per Year | 2,518.8% | 2,206.8% |
| Retained Earnings ($000) | | |
| Net Income After Taxes | $221,202 | |
| Less Allowance for Funds Used During Construction | 8,386 | |
| Less Dividends paid | 264,618 | |
| Total | $(51,802) | |
| Total Internal Cash Flow | $451,964 | |
| Percentage of Total Internal Cash Flow Maximum Total Contingent Liability Payable Per Year | 2,259.8% | |

Baltimore Gas and Electric Company

Underlying Assumptions for Projected Cash Flows

(1) Projected cash flow does not include an estimate of retained earnings. However, internally generated funds without retained earnings are well in excess of the maximum possible retrospective premiums.

(2) Depreciation is generally computed using composite straight-line rates applied to the average investment in classes of depreciable property. Vehicles are depreciated based on their estimated useful lives.

(3) Estimates of Federal income taxes and other tax expense are based upon existing tax laws and any known changes thereto.

(4) Accounting policies are consistent with those in effect June 30, 2000.

(5) Both the actual and projected data provided in this filing are for Baltimore Gas and Electric Company, which included the Nuclear Generation business through June 30, 2000. On June 30, 2000 the Nuclear Regulatory Commission approved the transfer of the Calvert Cliffs Nuclear Power Plant operating license from Baltimore Gas and Electric Company to Calvert Cliffs Nuclear Power Plant, Inc. (CCNPP). Effective July 1, 2000, in accordance with state legislation passed in November 1999, CCNPP became a separate unregulated company. In light of this change, all subsequent financial assurance filings will be provided by CCNPP.

# EXHIBIT IV

## NARRATIVE STATEMENT

## CURTAILMENT OF CAPITAL EXPENDITURES

**Baltimore Gas and Electric Company**
**Calvert Cliffs Nuclear Power Plant**
**August 15, 2000**

Exhibit IV

Baltimore Gas and Electric Company

Curtailment of Capital Expenditures

Estimated construction expenditures including nuclear fuel and Allowance for Funds Used During Construction for the twelve months ended July 31, 2001 are $450 million. To insure that retrospective premiums under the Price Anderson Act would be available during the aforementioned twelve month period without additional funds from external sources, construction curtailments would affect all construction expenditures rather than impacting a specific project.

# PACKAGE DIVIDER