George Vanderheyden
Vice President
Calvert Cliffs Nuclear Power Plant
Constellation Generation Group, LLC

1650 Calvert Cliffs Parkway
Lusby, Maryland 20657
410.495.4455
410.495.3500 Fax

Constellation Energy

July 30, 2004

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 our Calvert Cliffs Nuclear Power Plant reactors.

Exhibit I A copy of the 2003 Annual Report to Shareholders of Constellation Energy containing certified financial statements.

Exhibit II A copy of quarterly financial statements as of March 31, 2004.

Exhibit III The 2004 internal cashflow projection for Constellation Energy, which has been prepared in the format suggested in NRC Regulatory Guide 9.4.

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,

GV/CAN/bjd

Exhibits: As stated

cc: Document Control Desk, NRC

(Without Exhibits)
J. Petro, Esquire
J. E. Silberg, Esquire
Director, Project Directorate I-1, NRC
R. V. Guzman, NRC
H. J. Miller, NRC
Resident Inspector, NRC
R. I. McLean, DNR

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EXHIBIT I

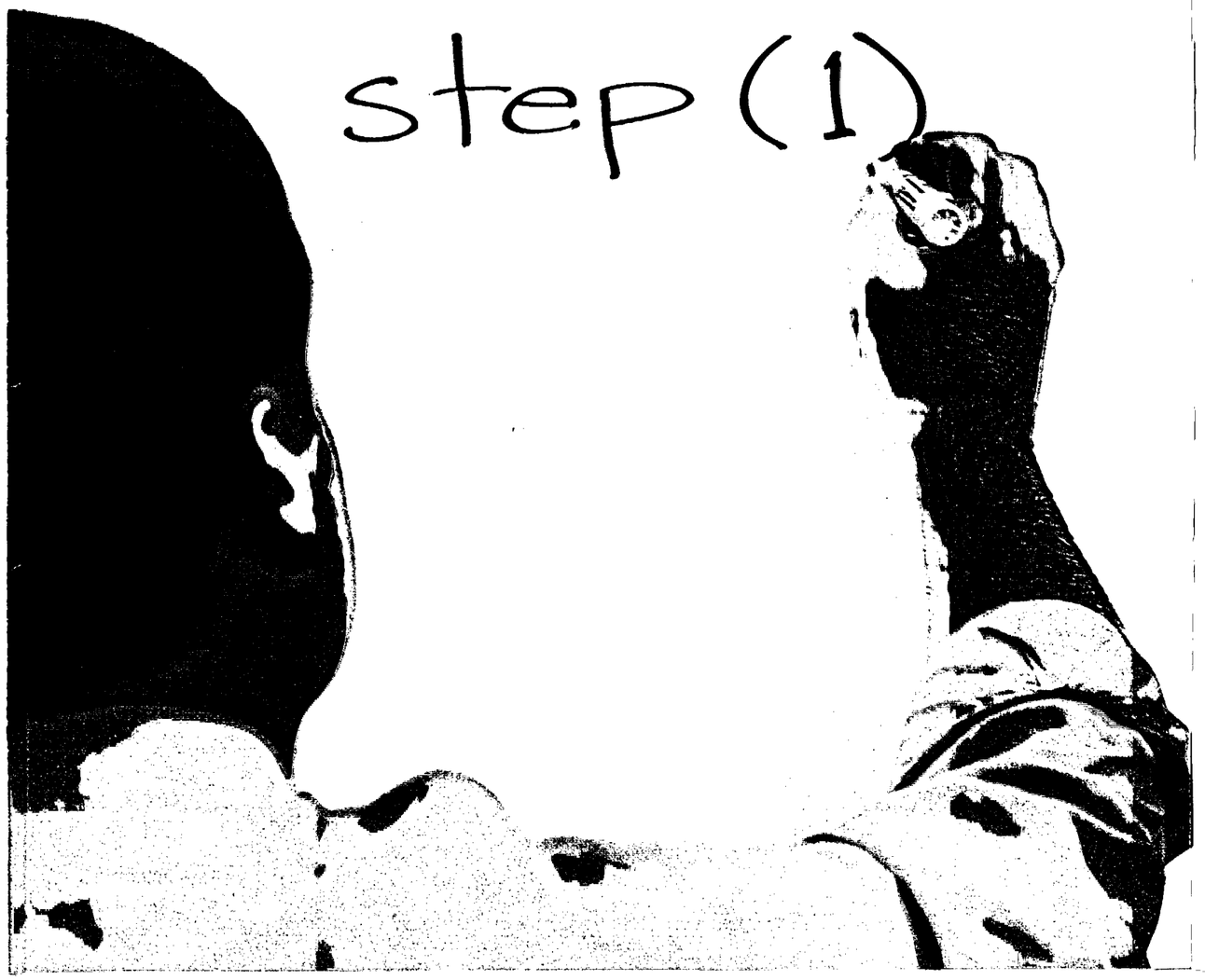
2003 ANNUAL REPORT TO SHAREHOLDERS

Calvert Cliffs Nuclear Power Plant, Inc.
July 30, 2004

Constellation Energy

2003 Annual Report

The Way Energy Works



Financial Highlights

In millions except per share amounts	2003	2002	% Change
Common Stock Data			
Reported (GAAP) earnings per share	$ 1.66	$ 3.20	
Cumulative effects of changes in accounting principles	$ (1.19)	–	
Special items*	$ 0.09	$ 0.68	
Earnings per share excluding cumulative effects of changes in accounting principles and special items**	$ 2.76	$ 2.52	9.5%
Dividends declared per share	$ 1.04	$ 0.96	8.3%
Average shares outstanding – assuming dilution	166.7	164.2	
Market price per share – year end	$ 39.16	$ 27.82	40.8%
Financial Data			
Total revenues	$ 9,703	$ 4,727	
GAAP net income	$ 277	$ 526	
Cumulative effects of changes in accounting principles	$ (198)	–	
Special items (after-tax)*	$ 14	$ 112	
Net income excluding cumulative effects of changes in accounting principles and special items**	$ 461	$ 414	
Total assets	$15,801	$14,943	
Total debt	$ 5,392	$ 5,051	
Total common equity	$ 4,141	$ 3,862	
Capital expenditures	$ 761	$ 923	

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

** Includes workforce reduction costs, impairment losses and other costs, and net gain on sale of investments and other assets.*

*** Represents a measure that is not determined in accordance with generally accepted accounting principles (GAAP) and should not be considered as an alternative to the comparable amount under GAAP. However, we believe that the impact of special items obscures trends in our results and that it is useful to consider our results excluding such items.*

2001 Earnings: For 2001, our GAAP earnings per share were $0.57. Excluding cumulative effect of change in accounting principle of $0.05 and special items of $(1.89), our earnings per share were $2.41.*

We're Constellation Energy (constellation.com), a Fortune 500 company based in Baltimore and the nation's leading competitive supplier of electricity to large commercial and industrial customers. We are one of the largest wholesale power sellers in the country. We also manage fuels and energy services on behalf of energy-intensive industries and utilities. We own and operate a diversified fleet of power plants throughout the United States. We deliver electricity and natural gas through Baltimore Gas and Electric Company (BGE), our regulated utility in Central Maryland. In 2003, the combined revenues of our integrated energy company totaled $9.7 billion.

The Way Energy Works ... at Constellation Energy

Our vision is to be the first-choice provider for customers seeking energy solutions in the complex and changing energy marketplace.

We're ...

- A Fortune 500 competitive energy company based in Baltimore.
- The nation's leading supplier of competitive electricity to large commercial and industrial customers.
- One of the nation's largest wholesale power sellers.
- A major generator of electricity with a diversified fleet of power plants strategically located throughout the United States.
- A regulated distributor – our Baltimore Gas and Electric utility – of electricity and natural gas in Central Maryland.

Our foundational values – integrity, teamwork, social and environmental responsibility, and customer focus – guide our actions.

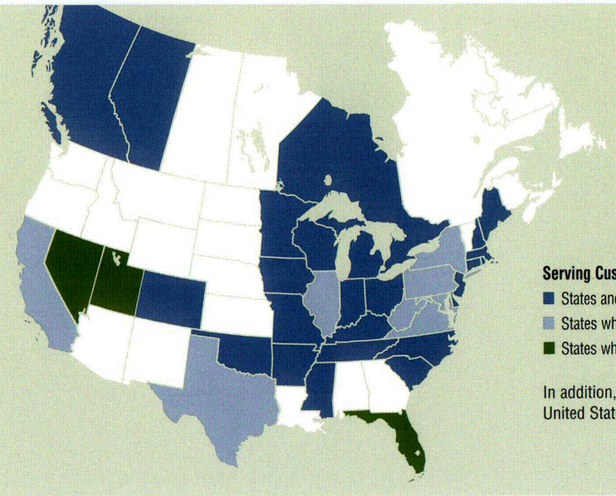
Our performance values – speed, accountability, passion for excellence, and creation of value – measure our results.

In 2003, we ...

- Provided a 45 percent total return to shareholders, assuming reinvestment of dividends.
- Earned $2.76 per share excluding the cumulative effect of changes in accounting principles and special items, a 9.5 percent increase from 2002.
- Had revenues of $9.7 billion.

In 2004, we're working to ...

- Continue creating shareholder value that will produce superior total returns.
- Continue achieving 10 percent growth in earnings per share.
- Implement productivity initiatives to help improve our earnings in 2005 and beyond.



Serving Customers Throughout North America

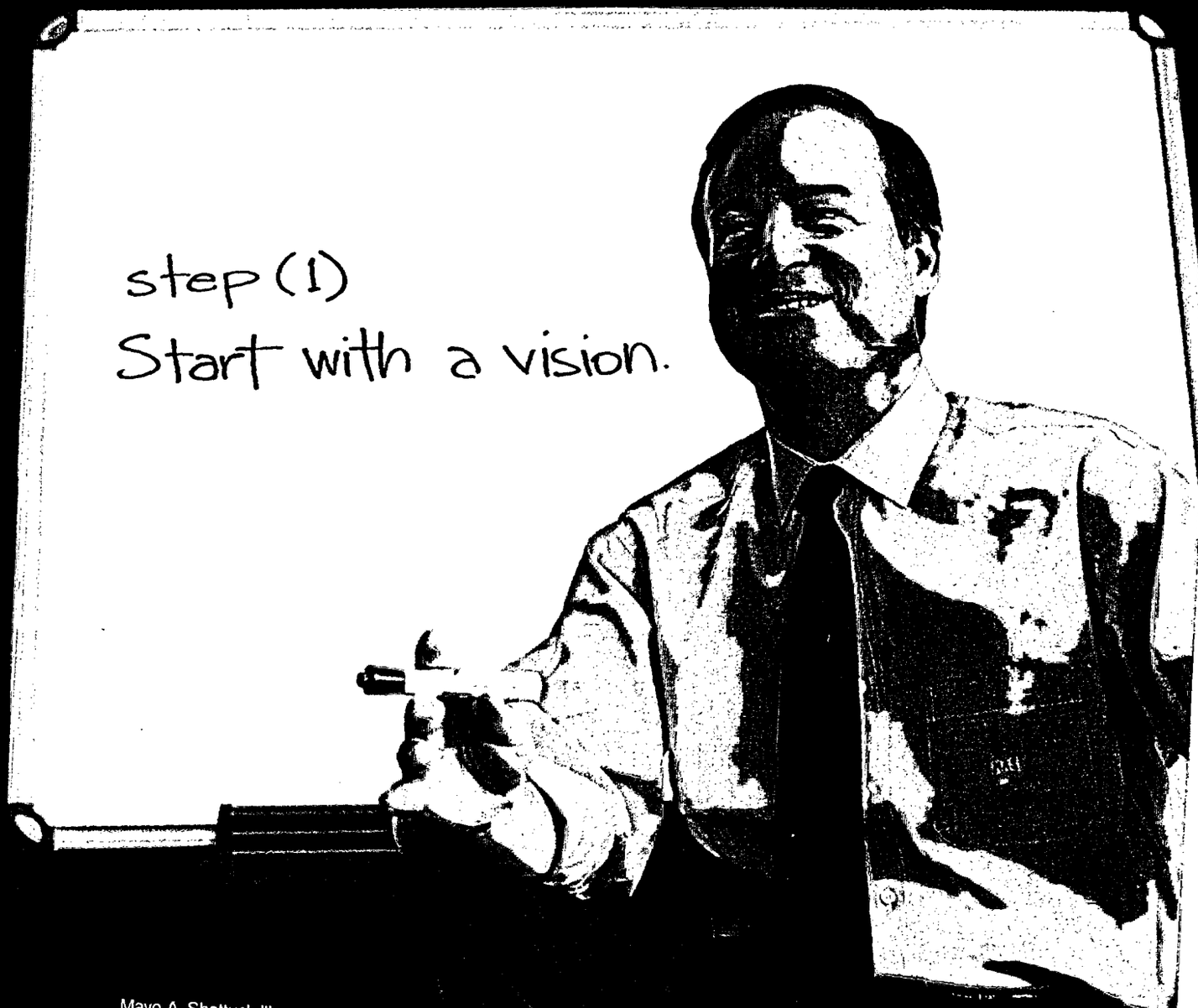
- States and provinces where we serve retail customers.
- States where we serve retail customers and have generation plants.
- States where we have generation plants.

In addition, we serve wholesale customers throughout the United States and Canada.

	Constellation Energy	Our Customers	How We Help Them	Our Markets	2003 Highlights	
Competitive Supply	**Constellation Power Source**	Premier wholesale customers who are intensive energy users – primarily distribution utilities, electric co-operatives, municipalities, and power marketers.	Provides reliable wholesale energy at predictable prices. Sells energy, capacity, risk management, and related products under short- and long-term contracts. Manages fuel and power logistics, and other energy services.	Competitive wholesale markets throughout North America – we handle a significant volume of the wholesale electric load for the Mid-Atlantic states, the Northeast, and Texas.	– Served 16,000 megawatts of peak load in the U.S. wholesale energy market. – Contracted to sell energy products and services that generated $186 million in current gross margin.	– Created $171 million worth of future gross margin – $132 million to be realized in 2004-2006. – Broadened our coal specifications and enhanced our coal supply chain to include more suppliers from more locations – saving between $10 million and $20 million in fuel costs annually through 2007.
Competitive Supply	**Constellation NewEnergy** **Constellation NewEnergy – Gas Division**	More than 8,000 large commercial and industrial customers – many with multiple locations – in nearly three dozen states and three Canadian provinces. 53 of the Fortune 100 companies – including Ford Motor Company, Hyatt Hotels, Kimberly-Clark, and Staples.	Provides specialized energy products and services that help customers effectively manage and control energy costs and usage based on their unique business requirements. Meets energy needs with: – Electricity and natural gas supply. – Risk management. – Load and usage management. – Procurement and cost management services.	Strategic, competitive markets across North America.	– Continued to grow market share to 16 percent of the competitive switched electricity market. – Acquired nearly 1,000 megawatts of customer contracts from other companies. – Added over 3,000 megawatts of new electric business, bringing total peak load served to over 8,000 megawatts. – Achieved a customer renewal rate of more than 80 percent. – Opened new offices in Dallas, Detroit, Calgary and Toronto.	– Significantly increased our natural gas capabilities with the acquisitions of Blackhawk Energy Services and Kaztex Energy Management, as well as with the acquisitions of retail gas contracts from other energy companies. – Expanded our natural gas operations in California, Illinois, Indiana, Michigan and Wisconsin. – Increased natural gas sales by nearly 30 percent, bringing total load to more than 195 billion cubic feet of natural gas.
Generation	**Constellation Generation**	Constellation Power Source sells all of the output from our generating plants to premier wholesale customers – primarily distribution utilities, electric co-operatives, municipalities, power marketers, and major independent system operators.	Generates reliable electricity under long-term contracts and spot market opportunities. Dispatches power to independent system operators as required to ensure reliability of the grid. Owns and operates more than 12,000 megawatts of generating capacity diversified by fuel, technology, and strategic geographic location.	Competitive wholesale markets across North America.	– Generated more than 50 million megawatt hours of electricity from our 107 generating units, a 15 percent increase over 2002. – Set a new world record for a two-piece steam generator replacement outage by completing the replacement at our Calvert Cliffs Nuclear Power Plant in 66 days.	– Reached an agreement to acquire the 495-megawatt Ginna Nuclear Power Plant in New York. – Started operations 60 days ahead of schedule at our new High Desert generating facility in California – which was also named *POWER* magazine Plant of the Year. – Received the National Safety Council Award at our Calvert Cliffs Nuclear Power Plant.
Energy Delivery	**Baltimore Gas and Electric**	1.2 million electric and 600,000 natural gas residential, commercial, and industrial customers.	Delivers electricity and natural gas to homes and businesses. Maintains and operates 250 substations, nearly 23,000 miles of distribution lines and 1,300 miles of transmission lines. Maintains and operates two peak-shaving plants, nine gate stations, and more than 6,000 miles of gas main. Enables customers to choose energy suppliers, and arranges supply for customers who have not chosen an alternate supplier.	Central Maryland – a 2,300-square-mile electric service territory, and an 800-square-mile natural gas service territory.	– Continued strong, stable earnings contribution to Constellation Energy's overall results. – Received the Emergency Response Award from the Edison Electric Institute recognizing our effective and efficient restoration of power to customers whose service had been knocked out by the devastation of Hurricane Isabel.	– Received Maryland Public Service Commission approval of Standard Offer Service bidding procedures for 2004. – Added 20,000 new customers. – Increased delivered electricity and natural gas volumes by 1.3 percent.
Energy Consulting/Services	**Fellon-McCord & Associates**	Large commercial and industrial customers – including Toyota, Hanson PLC, Wabash Alloys, and Church & Dwight Co., Inc.	Provides energy consulting and management services. Meets all natural gas and electricity supply, transmission, and distribution needs.	Energy markets across North America.	– Grew our customer portfolios in natural gas supply and transportation and electricity to $2 billion each – up from $1.5 billion each in 2002.	– Increased the number of customer facilities we serve by nearly 40 percent over 2002.
Energy Consulting/Services	**Constellation Energy Source**	Government and large commercial and industrial customers.	Provides customized solutions – utility infrastructure outsourcing (electricity, chilled water, heating), mechanical-electrical upgrades, utility data mining, and performance contracting – to increase energy efficiency, reliability, and cost effectiveness.	Energy markets across North America.	– Completed construction – seven months ahead of schedule – of the $48.2 million Nashville District Energy System facility.	– Began a long-term operations agreement with the city of Nashville to operate the District Energy System facility.
Energy Consulting/Services	**BGE HOME**	Residential and small commercial customers.	Provides energy-focused, essential products and services – heating and cooling systems, plumbing and electrical systems, home improvements, and appliance service.	Maryland.	– Successfully executed its repositioning strategy – moving the face of the company from the storefront to the service force.	– Built a state-of-the-art training center in Baltimore County to support technical trades personnel.

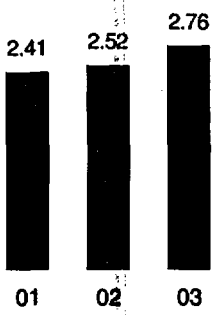
C01

At Constellation Energy, we know the way energy works. We have a plan, and we follow it – step by step.



Mayo A. Shattuck III
Chairman, President and
Chief Executive Officer

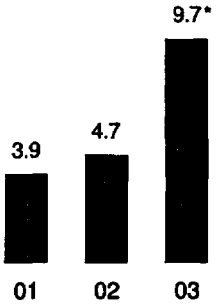
EARNINGS PER SHARE *(In dollars)*



Our earnings – excluding cumulative effects of changes in accounting principles and special items – increased 9.5% in 2003.

Note: Earnings as reported – our GAAP earnings – were: $0.57 in 2001, $3.20 in 2002, $1.66 in 2003. See the Financial Highlights table on the inside front cover for more details.

TOTAL REVENUES *(In billions of dollars)*



We've grown to a company with revenues of almost $10 billion in 2003.

** Includes approximately $1.4 billion effect of a change in accounting principle.*

We have a sustainable business model that allows us to be successful in competitive energy markets. We're one of the very few companies in our industry that has a strong growth story – growing 10 percent in a 3 percent industry. We are a stable, flexible, competitive company delivering results and creating value for our customers and shareholders.

step (1) Start with a vision.

Our vision is clear. We're working to be the first-choice provider for customers seeking energy solutions in the complex and changing energy marketplace. Our strategy starts and ends with our customers. Meeting their needs guides all that we do.

We're prospering and growing

We've transformed our company, building a business with almost $10 billion in revenues. We serve customers in nearly three dozen states and three Canadian provinces. Our large commercial and industrial customers include 53 of the Fortune 100 companies.

The markets rewarded our growth and performance during 2003. Our stock price appreciated nearly 41 percent. Including our $1.04 per share dividend, our total return to shareholders – assuming the dividend was reinvested – was 45 percent. In January 2004, we increased our dividend 10 percent to an annual rate of $1.14 per share.

In 2003, our earnings – excluding cumulative effects of changes in accounting principles and special items – increased 9.5 percent to $2.76 per share, up from $2.52 earnings per share in 2002.

We're doing it right

Our performance in 2003 is a strong affirmation that we have the right business model. We have the right pieces – a leading competitive supply business, a low-cost generation fleet, and a reliable customer-focused regulated utility.

To those pieces, we add intellectual capital, technology, market understanding, and disciplined risk management.

In advance of other companies, we saw the importance of transparency and built an infrastructure to provide the right metrics and accurately project our results. We have met or exceeded our earnings guidance in every quarter since then. That's nine consecutive quarters as of year end 2003.

We also expanded our risk and financial controls to ensure we are taking and managing risk in a manner in line with the interests of our shareholders. In disciplined fashion, over the last three years, we've found opportunities from among the fallen and restructuring energy companies. We held out for the right assets at the right prices – NewEnergy, Fellon-McCord/Alliance Energy Services, Blackhawk Energy Services, Kaztex Energy Management, the Nine Mile Point Nuclear Station, the Ginna Nuclear Power Plant, and several portfolios of customer contracts.

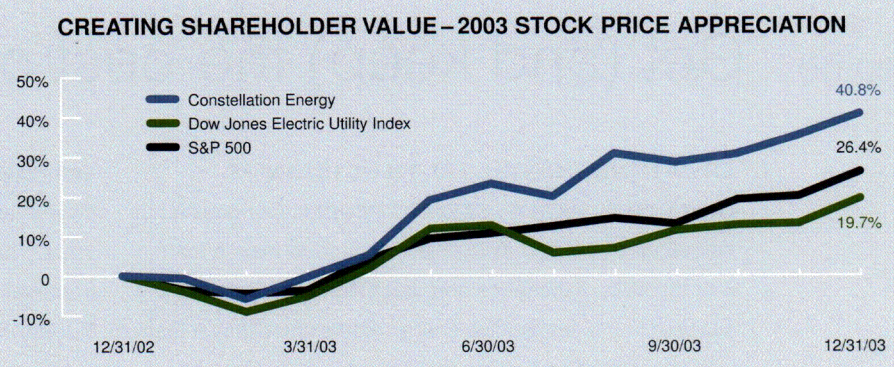
Our strong financial and operating results tell the story. Our growing sales force, increasing brand recognition, product excellence, credit strength, and leading management have us well positioned to continue prospering and growing.

We're reaching for the future

Reliable energy is critical to our economy and our quality of life. Two events during 2003 provided an unwelcome experience of life without energy.

In August, the largest blackout in history hit eight Midwest and Northeast states and Canada. Major cities – including New York, Toronto, Cleveland and Detroit – were left without power. More than 50 million people were affected, some for days. While this cascading blackout did not affect our transmission system or utility operations,

Beating the averages. Our stock price appreciated 40.8% in 2003, significantly better than the Dow Jones Electric Utility Index and the S&P 500. An investment of $100 in Constellation Energy common stock on December 31, 2002 was worth – with dividends reinvested – $145.21 on December 31, 2003.



it did impact our Nine Mile Point Nuclear Station in New York. We brought the plant safely off line and then back on line as soon as conditions allowed.

In September, Hurricane Isabel hit the Mid-Atlantic states, causing $200 million in damage. It disrupted service to 3.1 million customers – including 790,000 customers of BGE, our regulated utility in Central Maryland.

Our planning and preparation paid off, and we were able to restore service to all of our BGE customers in eight days. For our efforts, we received the Edison Electric Institute Emergency Response Award.

While hurricanes cannot be avoided, this blackout could have been. Its causes and effects are symptomatic of the challenges within our fragmented industry.

Imagine the inefficiencies and complexities if every major city or state had its own particular airline and air traffic control system ... its own unique computer technology and operating system ... its own independently operated postal service. All with little or no common standards, or incentive to work together. That describes the fragmentation of today's energy industry.

It's clear that well-functioning competitive energy markets need standards. They must have a solid structure, clear rules, a number of competing suppliers, and an open and reliable transmission system. Customers do not benefit fully from markets in which individual companies discriminately control when and how much energy they can receive ... and at what price they can receive it.

At a time when customers would benefit from well-functioning competitive markets, some companies in our industry are grabbing for the past. They've retreated from competitive markets, attempting to restructure back into the old regulated utility model.

We – on the other hand – are reaching for the future. Our progressive strategy is distinct from many companies in our industry. It creates a business designed to succeed in the reality of today's competitive markets.

The future is competitive markets

We believe competitive markets will continue to evolve and grow, eventually dominating the energy landscape and leading to innovations, efficiencies and growth. Competition is in the best interests of energy customers, and it's good for our economy. Customers need and want convenience, reliability and efficiency – all at the best value.

In regulated markets where customers have only one supplier with no ability to choose, the level of convenience, reliability, efficiency and value is limited by the capability, willingness and motivation of their one supplier.

In competitive markets where customers can choose suppliers, the level of convenience, reliability, efficiency and value continuously improves with the technologies and skills of companies competing to be the best at meeting customers' energy needs.

By letting fair competitive markets work, our industry will create the potential for developing new ways to deal with environmental challenges and reliability issues, while also sending appropriate market signals that will ensure we have the right amount of generating capacity.

Regulated markets provide no incentives to be innovative. Competitive markets do.

The way energy works

We're redefining America's energy industry, and we're excited about it. Customers, investors, financial analysts and even other energy companies have taken note.

I am energized, my team is committed, and our employees are focused on the opportunity at hand.

We know the way energy works. We also know the opportunity competitive markets present to create value for our customers, our economy, our quality of life, and for our shareholders. And we'll work tirelessly to realize that value.

Sincerely,

Mayo A. Shattuck III

Mayo A. Shattuck III
Chairman, President and Chief Executive Officer
March 15, 2004

C02

step (2) Get (and keep) the best of the best.

IT'S A FUNDAMENTAL TRUTH OF BUSINESS – GROWTH ATTRACTS STRONG PEOPLE. Our growth has helped us attract and assemble a high-performance team with the skills, experience and determination needed to succeed in the competitive energy marketplace. It is a team with a wealth of energy expertise, competitive business experience, and know-how in developing and implementing best practices. We have been putting the right people in the right places to successfully run and grow our business.

By adding key senior leaders and managers with the best talent outside our industry to the unsurpassed energy expertise already within our company, we've become a diverse and strong team focused on creating shareholder value. The fruits of our teamwork can be seen everywhere – from Wall Street's positive response to our proposed Ginna Nuclear Power Plant acquisition ... to the remarkable growth of our competitive supply business ... to the phenomenal effort to restore power to BGE customers following Hurricane Isabel.

Our people – the entire Constellation Energy workforce – drive our future. Our employees win when our company wins. And our shareholders win with the value we create.

Our 8,650 employees collectively form a high-performance team that has the skills, experience and competitiveness to make us a leading North American energy company and create value for our shareholders. Meet just a few of our team members ...

Beth Perlman
Transforms the way we work by building a new information technology platform that reduces our 35 desktop configurations to five, consolidates our financial systems, and implements a new human resources system.

Phil O'Connor
Spearheaded an effort that helped define and make competitive market rules in Illinois effective through the end of 2006, eliminating uncertainties customers had in switching energy suppliers.

Jeannette Mills
Leads her team in streamlining BGE's new-service request and installation process, providing a positive first experience to the 20,000 new customers our distribution utility gains annually.

Roger Cockroft
Guides our Six Sigma program using his unique expertise gained from consulting with and helping some of the world's largest companies get better at what they do.

Kurt Duerod
Started and leads a real-time operations team that monitors our North American energy contracts and fills our customers' power needs 24/7.

Dale Linaweaver
Drives an effort to maximize the value of our generating plants by creating a franchise of best practices that can be used by our entire generating fleet and applied to any acquisitions we may make.

Tom Restuccio
Brought our Nine Mile Point Nuclear Station safely off line and then safely back on line during the uncertainty and disruption caused by the black-out in the Northeast last summer.

WE'RE NEVER DONE. Success in competitive markets requires constant improvement.

Ours is a culture of ongoing improvement, and our efforts to increase productivity are deep and widespread. Over the last two years, we've significantly improved our cost structure. This year, we're investing in initiatives that will make us even more efficient – including rebuilding our information technology infrastructure and revising and streamlining our policies, practices and processes.

At our generating plants, our initiatives work toward reducing the duration of outages and increasing the reliability, availability, and capacity of our plants.

In 2003, our high-performance teamwork and meticulous planning enabled us to replace a steam generator at our Calvert Cliffs plant in 66 days. That set a new world record for steam generator replacements, while minimizing the plant's down time.

Incorporating lessons learned and striving to implement best practices has long been a part of the way we do business. And programs like Six Sigma – a rigorous, managed process that puts the power to make changes in our employees' hands – is helping us do even more. Our goal is best in class, top quartile in all measures. And that means always improving what we do.

step (3) Get better. Period.

Burt Jackson
Enhanced BGE's reliability and customer satisfaction by implementing significant productivity improvements in our gas main maintenance work.

Dave Sikora
Applies more than 20 years' experience at BGE to help this subsidiary become an industry leader in Six Sigma productivity improvements.

Jeanne Blondia
Uses her experience in large, competitive corporations to help further strengthen our balance sheet and its position as one of the strongest in our industry.

Deirdre Lord
Heads a team whose energy, sales, operations, marketing and regulatory expertise makes it a leader for electricity supply to commercial and industrial customers in New York and New Jersey.

Dave Boward
Manages High Desert, our new environmentally friendly power plant in California that began operations nearly 60 days ahead of schedule and was named *POWER* magazine's 2003 Power Plant of the Year.

Randall Hartman
Championed – along with a national group of professionals – an accounting standards change that provides a clearer picture of energy delivery contracts.

Shameek Konar
Puts nearly 10 years of U.S. energy markets experience to work in pricing and acquiring natural gas for our power plants, and expanding our hydrocarbons business.

A wholesale knowledge of energy
Fluctuations in weather, power plant production, transmission congestion and other factors create a dynamic, always-changing wholesale energy market. Stuart Johnson and our competitive wholesale energy team stay on top of the market 24/7, making sure customers' energy needs are met. That helps make us one of the leading suppliers of competitive wholesale energy in North America.

step (4) Sweat the small stuff.

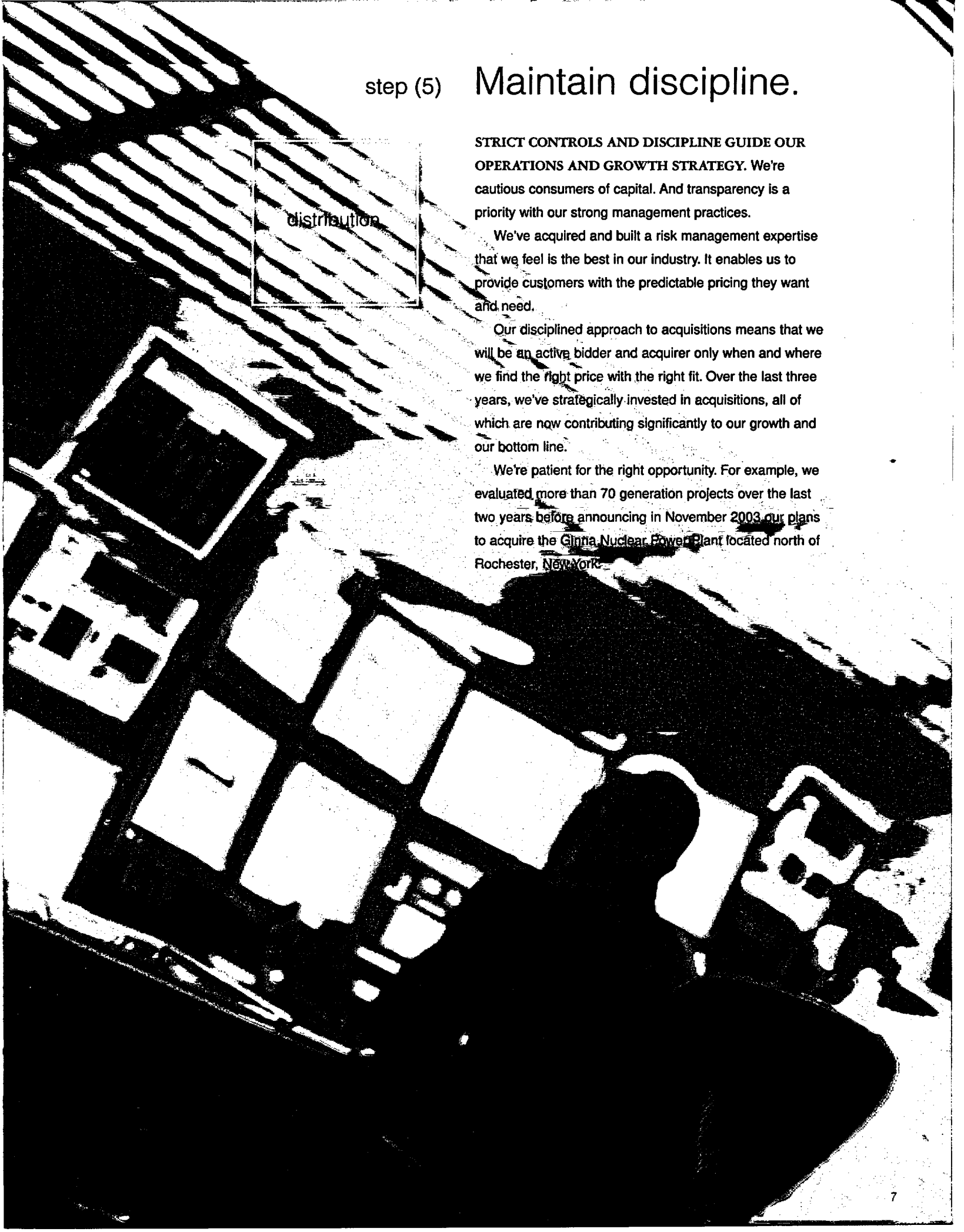
OURS IS A PHYSICAL BUSINESS. We generate and buy energy. We handle the logistics of supplying and delivering it to customers. And we manage the risk associated with the pricing and reliability.

We deliver energy products and services to real customers, and we employ real assets – including the more than 12,000 megawatts of our national fleet of generating plants – on a recurring and repeatable basis.

In short, we sweat the details to get energy to our customers. We get it to them when they need it and where they need it, and at prices that help them manage their energy costs.

In complex deregulated markets, serving customers reliably and adding value requires deep understanding of the variability, consumption and nuances of thousands of nodes in delivery and generation networks.

That is the physical nitty gritty of energy. And that is what makes us an important partner with our customers – utilities, integrated utilities, municipalities, cooperatives, and large commercial and industrial businesses.



step (5) Maintain discipline.

STRICT CONTROLS AND DISCIPLINE GUIDE OUR OPERATIONS AND GROWTH STRATEGY. We're cautious consumers of capital. And transparency is a priority with our strong management practices.

We've acquired and built a risk management expertise that we feel is the best in our industry. It enables us to provide customers with the predictable pricing they want and need.

Our disciplined approach to acquisitions means that we will be an active bidder and acquirer only when and where we find the right price with the right fit. Over the last three years, we've strategically invested in acquisitions, all of which are now contributing significantly to our growth and our bottom line.

We're patient for the right opportunity. For example, we evaluated more than 70 generation projects over the last two years before announcing in November 2003 our plans to acquire the Ginna Nuclear Power Plant located north of Rochester, New York.

step (6)

Keep it simple.

OUR CUSTOMERS' ENERGY NEEDS ARE COMPLEX. Our job is to make it simple for them.

We're relentless and rigorous in our approach to meeting our customers' total energy needs. We analyze their requirements, supply their energy, help them manage consumption, and offer various options to control price volatility.

Customers in deregulated areas throughout North America view us as their one-stop, national energy shop. With electricity and natural gas capabilities, we serve customers in nearly three dozen states and three Canadian provinces. In these areas, we provide competitive energy and value-added services to more than 8,000 large commercial and industrial customers.

We bring regional expertise to all deregulated energy markets. Plus we have a physical presence that allows us to assist with changing local and regulatory conditions, as well as to provide customized products and pricing, and superior customer service.

Our mission is to have customers in competitive energy markets choose us first and always. And they have been.

One-stop shopping
We're making complex energy markets simple for Gregg Bowler, vice president and chief financial officer at Wabash Alloys, the world's largest producer of recycled aluminum casting alloys. We provide Wabash with a one-stop shop for natural gas supply, and energy consulting and management expertise.

Knowing the market
In Chicago and Cincinnati, we're helping nearly a dozen major Hyatt hotels meet their energy needs efficiently. Brian Burke, director of energy for Hyatt Hotels Corporation, chose us because of our regional expertise in newly deregulated markets.

Customizing solutions
Ryan Lowery, senior purchasing agent for Church & Dwight Co., Inc., producer of Arm & Hammer® baking soda, turns to us for customized solutions to meet the energy needs of each of the company's nine plants.

Taking the hassle out
We've taken the hassle out of buying energy for Bob Valair, Staples' director of energy and environmental management. We provide power for Staples locations in Massachusetts and Michigan – all under one contract.

Doing it all
By supplying the town's full energy requirements, we help Dick Joyce, director of the Wellesley Municipal Light Plant, provide Wellesley's 27,000 residents with reliable and efficient electric power at fair and competitive rates.

step (7) Be accountable.

WE ANSWER TO OUR CUSTOMERS. We provide them with tailored energy products – electricity, natural gas, energy services, and pricing options that limit volatility – to meet their specific needs. All at the best value.

Our customers count on our financial strength. Backed by a strong balance sheet, cash flow, and credit ratings, we have the dependability and reliability that they want and need.

We also answer to our shareholders. Our leadership in financial disclosure and integrity – our strong internal financial controls and corporate compliance program, along with the independence of our Board of Directors and auditors – provides a clear look at what we do and how we're doing at it.

We're a model business within America's energy industry. We're also a leading advocate for competitive markets and a national energy policy that supports good market design – a level playing field for all participants, effective and sensible environmental outcomes, and disciplined business practices.

CREATING VALUE FOR OUR SHAREHOLDERS DRIVES ALL THAT WE DO. We have an unflinching commitment to winning in competitive markets and an absolute obsession with executing our strategy successfully. We're a dynamic, growing energy company that's doing things right. In 2003, our stock price appreciated nearly 41 percent. Combined with our $1.04 dividend per share – assuming it was reinvested – our total return to shareholders was 45 percent.

While we can't expect those levels of return every year, our goal is to provide a superior long-term return. We are a financially strong company. Our balance sheet is one of the best in our industry.

We're a solid investment. We're aiming to achieve 10 percent annual earnings growth and pay dividends in line with our earnings.

step (8) Make a difference.

C03

IT'S THE WAY WE LIVE OUR LIVES THAT SHAPES OUR CULTURE AND DEFINES OUR REPUTATION.

For generations we have carried out a commitment to community partnership – working to build and support the communities we serve.

Through thoughtful social investments, we strive to enhance the quality of life for the communities surrounding our operations. We also work to earn their trust by putting our environmental policy into practice every day.

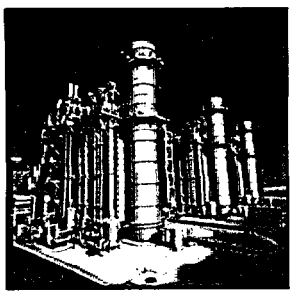
For example, over the last three years, we've reduced our power plant emission rates by an average of 30 percent while generating nearly 30 percent more electricity.

In 2003, our total contributions to community and environmental groups were $4.3 million. We were the largest philanthropic corporate giver in Central Maryland, and the largest contributor to the United Way in Maryland and Oswego, New York.

In addition to these contributions, we sponsored the Constellation Energy Classic – a professional golf tournament on the Champions Tour – which contributed $300,000 to the Kennedy Krieger Institute, Living Classrooms Foundation, and The Chesapeake Bay Foundation.

We rest only when the lights are on
Before Hurricane Isabel knocked out power for 790,000 BGE customers, we were ready. Then, working around-the-clock, and averaging 15,000 hours per day of restoration work, we replaced more than 400 poles, 300 transformers, 33,000 fuses, and 100 miles of wire. We restored service to all our customers in eight days. Our efforts earned us the Edison Electric Institute Emergency Response Award, and letters of thanks from people like eight-year-old Rebecca Oh. She wrote: *Dear BGE... I hope you have a lot of rest when you are done. Thank you for working overtime to get my power back on.* You're welcome, Rebecca. That's our job.

An environmental friend
Our new, state-of-the-art High Desert plant in Southern California received *POWER* magazine's Power Plant of the Year award for being 2003's most innovative, efficient and environmentally sound power project.



Building community
We contributed $1 million to the restoration of Baltimore's majestic Hippodrome theater. The reopening of this 90-year-old, 2,300-seat theater has been a catalyst for rejuvenating the city's west side.

step (9) Be responsible

Our business model is designed for today's energy marketplace. We believe competitive markets will grow and eventually dominate the landscape. We have found that our customers want the advantages that come from being able to purchase a tailored energy product. They also want a one-stop provider that will supply the energy they need, when they need it, and with pricing certainty. Our business model makes us that one-stop provider. And we believe there are none better than we are.

Mayo A. Shattuck III
Chairman, President and Chief Executive Officer

step (10) Answer the important questions.

Why was 2003 such a great year for Constellation Energy?
It was a transforming year for us. While some companies in our industry continued to retreat to the old utility model of the past, we continued to operate and build a company for the future. We aligned our physical assets with wholesale and commercial and industrial customers in competitive markets. We continued to grow, both organically and through acquisitions. Most important, we did an excellent job executing our customer-centric strategy.

No one is better than we are at meeting the complex physical energy needs of customers in competitive markets. Our results – and our continuing growth – make that clear. We're succeeding because we're doing it right – combining physical assets and financial strength with strong risk management controls and market expertise.

What does it mean to be the leading energy company we talk about in our vision?
It means being a leading supplier of competitive energy in North America, providing the best products and service to customers. The performance of our generating facilities must rank among the top 10 percent in our industry. The reliability of our transmission and distribution operations must be a given. Our unsurpassed risk management skills must keep their leading edge. We must focus on meeting our customers' needs all along the energy value chain, from our efficient management of energy logistics to the intermediary role that we play between generators and distributors of power.

What will our company look like in five years?
We expect that we will be the leading energy provider in competitive markets – serving load to wholesale customers, selling and supplying energy to commercial and industrial customers throughout North America, and managing hydrocarbons, including coal, gas, and other fuels. In addition, through BGE we will maintain a growing, customer-service oriented regulated utility business.

In what markets will we be a competitor?
We plan to be an active participant in all deregulated energy markets. We expect to enter regions as they deregulate and open up to competition. Our strategy has been to gain a footprint – a generating plant, or energy services capabilities, or a portfolio of energy contracts or customers. We then take advantage of our regional and competitive expertise to grow our business.

Why is continuing deregulation throughout the United States important to our business model?
We are building our company to be a leading North American competitive energy company.

Over the short term, we are not relying on either federal deregulation or an ever-increasing number of state-level deregulations to achieve our growth objectives. There is plenty of growth available in markets that have deregulated and are open to competition.

Over the long term, we believe deregulation will continue and increase. As that happens, there will be winners and losers among energy companies. We intend to be a winner.

Why are we making an effort to build the Constellation Energy brand?
We are a customer-centric business operating in competitive markets. Our branding efforts will help articulate why we are different and how we create value for customers. Although energy itself is a commodity, the service we provide is not. There are various options for pricing, risk tolerance, physical delivery, billing, and management. Customers want confidence in their energy supplier's skill set, product depth, creditworthiness, and dependability.

What's your view on industry consolidation?
The regional structure of our industry is inefficient. Consolidation generally improves service levels and reduces costs. That's what happened with consolidation in the telecommunications, retail, pharmaceutical distribution, air travel, and other industries.

While our industry has its own specific issues – a myriad of federal and regional issues and concerns – I believe consolidation would lead to improved service, lower costs, increased innovation, and other benefits to our customers.

What is our acquisition policy?
We only make an acquisition when it is a strategic and financial fit – the right asset in the right location at the right price. We're cautious consumers of capital and disciplined in our deployment of funds. That approach has paid off with the acquisitions we've made over the last three years – NewEnergy, Fellon-McCord/Alliance Energy Services, Nine Mile Point Nuclear Station, and various portfolios of customer contracts. We've been very successful at integrating them into our business and achieving exceptional returns.

We applied the same approach to our 2003 acquisitions – Blackhawk Energy Services and Kaztex Energy – and to our agreement to purchase the Ginna Nuclear Power Plant. And we expect good results from those investments.

How do you grow 10 percent in a 3 percent industry?
We grow 10 percent by increasing our share in competitive energy markets, continuously making productivity improvements, and being disciplined in our deployment of capital.

Our leading market share in competitive retail electricity markets where we participate has grown to 16 percent, and we have plans in place to drive it to 21 percent by 2007. Over the last two years, we have made significant progress in improving our cost profile, and our efforts over the next few years should produce significant additional results.

How do we build value for our shareholders?
We build value for our shareholders by growing our business and meeting our earnings targets. We believe that strong earnings growth should drive long-term stock appreciation and a premium stock price-to-earnings ratio.

In 2003, our stock price appreciated almost 41 percent. Adding the dividend – assuming it was reinvested – total return to shareholders was 45 percent. While that's an exceptional year, we have a long-term focus. I believe that if we continue to execute our strategy and meet our goals, we'll also continue to produce superior long-term total returns and create greater value for our shareholders.

What is our dividend policy?
We strive to make the most effective use of our earnings by paying dividends, reinvesting in our business, and reducing debt. Our focus is on maximizing shareholder value and total shareholder return.

We plan to raise our dividend in line with our earnings growth as long as it continues to make good business sense. In January 2004, we increased the dividend by 10 percent to an annual rate of $1.14 per share. This is the third consecutive year we've increased the dividend.

How will you spend most of your time during 2004?
In 2003, we created a chief administrative officer position to oversee more of the day-to-day operations of our business. That frees my time to focus more on future strategic issues. We are one of the nation's leading competitive energy companies, and we have experience and perspectives that can be helpful in various discussions about our industry. I'm going to be working to ensure that we have an appropriate presence among thought-leaders and other participants in any efforts concerning the future of our energy industry and markets.

Board of Directors

Our Board of Directors has the responsibility to oversee and direct management activities to enhance the long-term value of our company for our shareholders and other constituents. We have 12 independent directors, one director who is an employee, and one director who is a retired employee. Our Audit, Compensation, and Nominating and Corporate Governance committees are made up entirely of our independent directors.

Yves C. de Balmann
Co-Chairman
Bregal Investments
Age 57
Director since 2003

James T. Brady
Managing Director, Mid-Atlantic
Ballantrae International, Ltd.
Age 63
Director since 1999

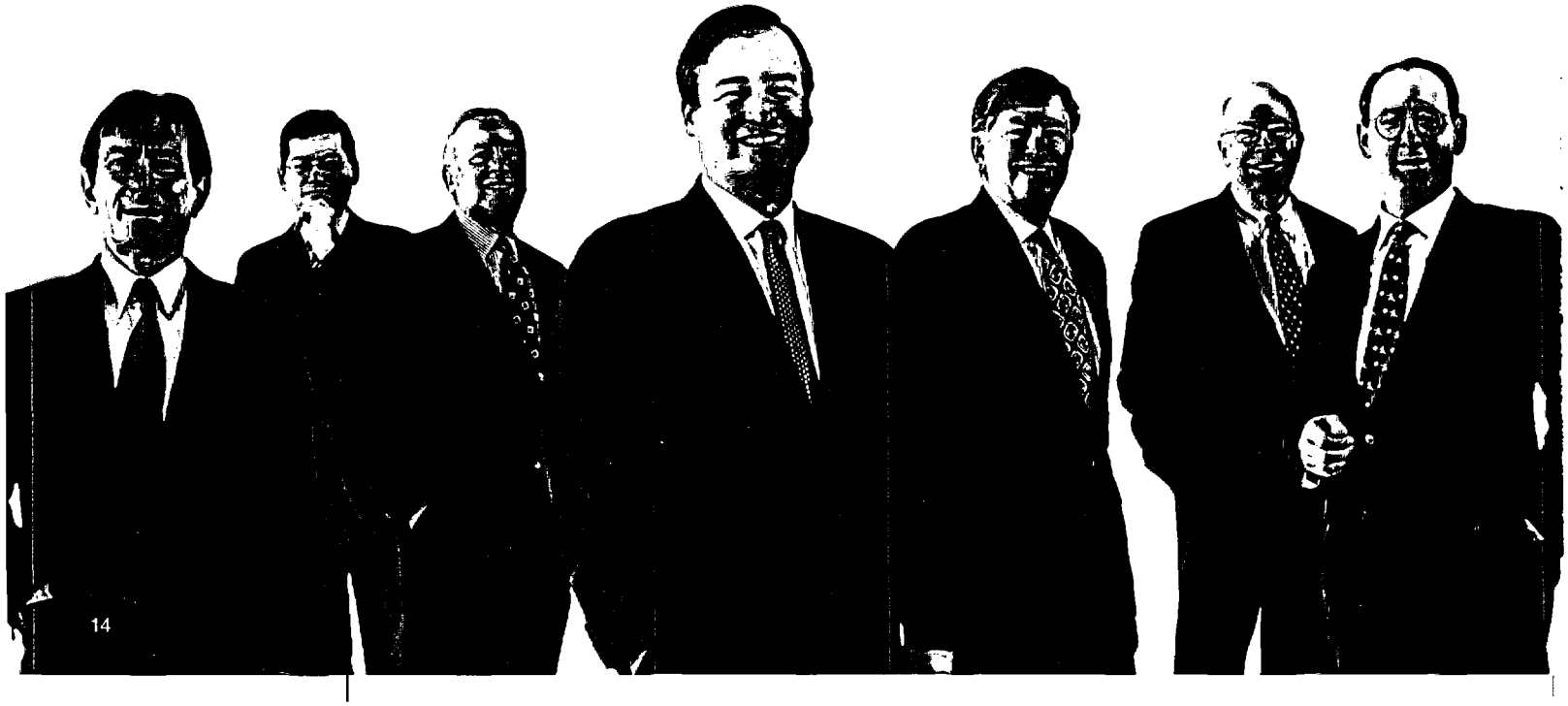
Frank P. Bramble, Sr.
Vice Chairman
MBNA Corporation
Age 55
Director since 2002

James R. Curtiss, Esq.
Partner
Winston & Strawn
Age 50
Director since 1994*

Douglas L. Becker
Chairman and Chief
Executive Officer
Sylvan Learning Systems, Inc.
Age 38
Director since 1998*

Mayo A. Shattuck III
Chairman, President and
Chief Executive Officer
Constellation Energy
Age 49
Director since 1999

Edward A. Crooke
Retired Vice Chairman
Constellation Energy
Age 65
Director since 1988*



Corporate Governance

During 2003, we focused on implementing industry-leading corporate governance principles, including the adoption of new Corporate Governance Guidelines, the creation of a Corporate Compliance Program, the updating of the charters of each of the committees of the Board of Directors, and the implementation of Principles of Business Integrity that apply throughout our entire organization. In addition, our Board has named Michael D. Sullivan, one of our independent directors, to serve as its Lead Director.

Committees of the Board

Executive Committee
Mayo A. Shattuck III, Chairman
Frank P. Bramble, Sr.
Edward A. Crooke
Edward J. Kelly III
Robert J. Lawless

Audit Committee
James T. Brady, Chairman
Yves C. de Balmann
Freeman A. Hrabowski III
Nancy Lampton

Compensation Committee
Robert J. Lawless, Chairman
Douglas L. Becker
Frank P. Bramble, Sr.
Edward J. Kelly III
Lynn M. Martin
Michael D. Sullivan

Committee on Nuclear Power
James R. Curtiss, Chairman
Edward A. Crooke
Roger W. Gale

Nominating and Corporate Governance Committee
Michael D. Sullivan, Chairman and Lead Director
Douglas L. Becker
Frank P. Bramble, Sr.
Edward J. Kelly III
Robert J. Lawless
Lynn M. Martin

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

Roger W. Gale
Partner
GF Energy, LLC
Age 57
Director since 1999

Edward J. Kelly III
Chairman, President and Chief Executive Officer
Mercantile Bankshares Corporation
Age 50
Director since 2002

Robert J. Lawless
Chairman, President and Chief Executive Officer
McCormick & Company, Inc.
Age 57
Director since 2002

Michael D. Sullivan
Chairman
Life Source, Inc.
Age 64
Director since 1992*

Dr. Freeman A. Hrabowski III
President
University of Maryland Baltimore County
Age 53
Director since 1994*

Nancy Lampton
Chairman and Chief Executive Officer
American Life and Accident Insurance Company of Kentucky
Age 61
Director since 1994*

Lynn M. Martin
Advisor
Deloitte & Touche LLP
Age 64
Director since 2003

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

Thomas F. Brady
Executive Vice President, Corporate Strategy & Retail Competitive Supply, Constellation Energy
54, joined BGE in 1969. In addition to corporate strategy (since 1999), serves as Board Chairman and managing executive for Constellation's recently acquired NewEnergy companies, BGE Home, Constellation Energy Source and Constellation's portfolio of nonregulated ventures. Prior to 1999 he held various positions at BGE, including Chief Accounting Officer and VP, Customer Service & Distribution.

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

Executive Team

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

Paul J. Allen
Senior Vice President, Corporate Affairs

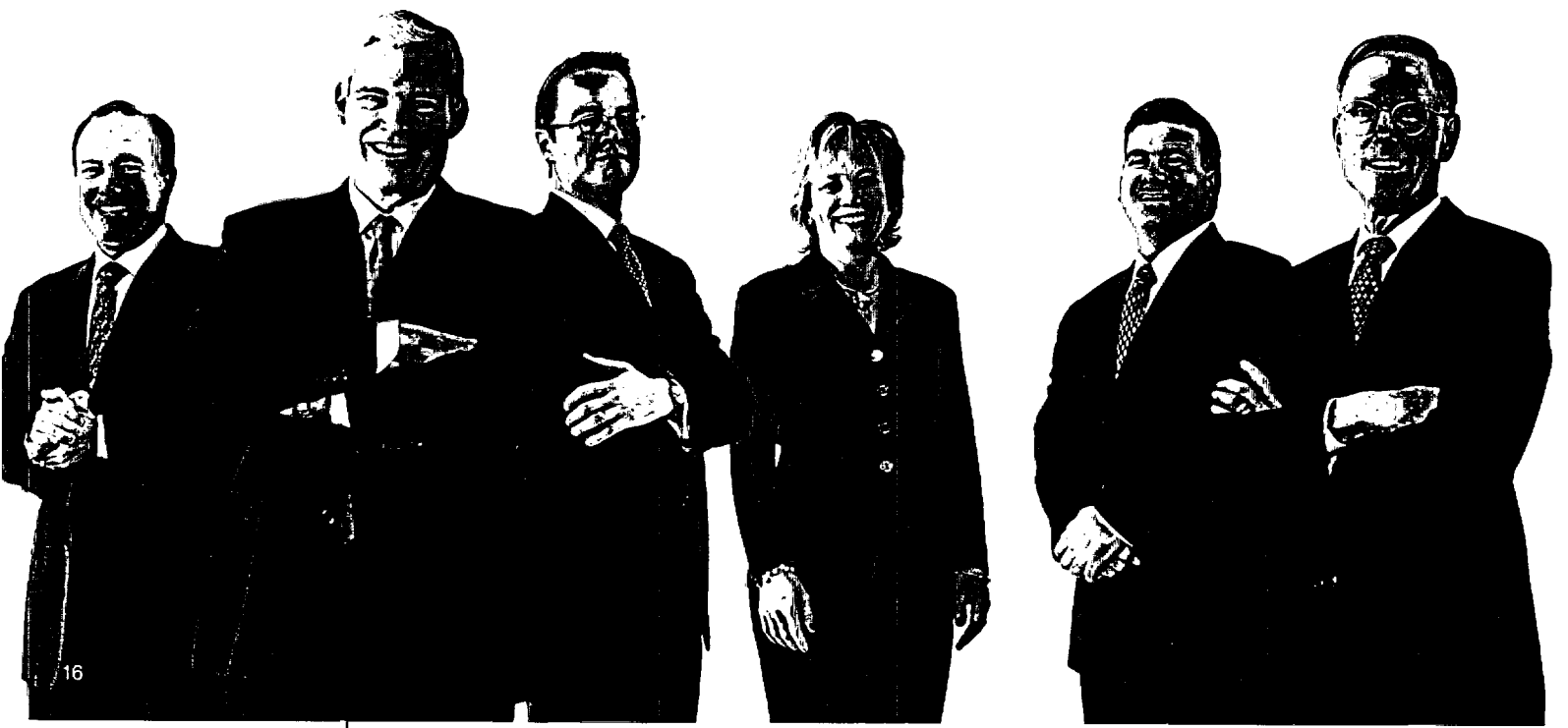
Thomas F. Brady
Executive Vice President, Corporate Strategy & Retail Competitive Supply

Thomas V. Brooks
Executive Vice President, Constellation Energy and President, Constellation Power Source

Kathleen A. Chagnon
Senior Vice President, General Counsel, Corporate Secretary & Chief Compliance Officer

John R. Collins
Senior Vice President & Chief Risk Officer

Frank O. Heintz
Executive Vice President, Constellation Energy and President & Chief Executive Officer, Baltimore Gas and Electric Company



Kathleen A. Chagnon
Senior Vice President, General Counsel, Corporate Secretary & Chief Compliance Officer, Constellation Energy
44, joined Constellation in 2002. Before this she was VP and Corporate Group General Counsel for The St. Paul Companies, Inc. She was also Assistant VP and Associate Group Counsel of USF&G Corporation until its acquisition by The St. Paul Companies in 1998. She held associate positions in two international law firms, Hogan & Hartson and O'Melveny & Myers.

Frank O. Heintz
Executive Vice President, Constellation Energy and President & Chief Executive Officer, Baltimore Gas and Electric Company
60, joined BGE in 1996 as VP, assuming leadership of its Gas Division in 1997; elected Executive VP, BGE Utility Operations in 1998, and became BGE President in 2000. Prior to this he served 13 years as Chairman, Maryland Public Service Commission. Previous jobs include Executive Director, Maryland Employment Security Administration; Special Assistant to Maryland Lieutenant Governor Blair Lee III, and state legislator.

Mayo A. Shattuck III
Chairman, President & Chief Executive Officer, Constellation Energy
49, appointed President and CEO of Constellation November 2001 and elected Chairman of the Board in July 2002. Prior to Constellation, he was with Deutsche Bank and served as Chairman of the Board of Deutsche Banc Alex. Brown and, during his tenure, served as Global Head of Investment Banking and Global Head of Private Banking. Previously, he was Vice Chairman of Bankers Trust and President of Alex. Brown & Sons.

Marc L. Ugol
Senior Vice President, Human Resources, Constellation Energy
45, joined Constellation in 2002. Prior to this he was SVP of Human Resources at Tellabs, Inc., a global telecom equipment manufacturer. Previously, he held human resource management positions at Platinum Technology, Inc., and System Software Associates, Inc., and spent 14 years with Amoco Corp. in a variety of HR leadership roles.

John R. Collins
Senior Vice President & Chief Risk Officer, Constellation Energy
46, joined BGE in 1988; named Assistant Treasurer and Director of Financial Management in 1995; joined Constellation Power Source at its formation in 1997, serving as its senior financial officer; became Managing Director-Finance and Treasurer, Constellation Power Source Holdings in 2000 and was elected to his current position in 2001.

Mark P. Huston
Vice President, Corporate Strategy & Development, Constellation Energy
41, joined BGE in 1986; in 1993 was General Supervisor in the Gas Construction Division, and in 1996 was promoted to Director of Gas Business Development. In 1997 he was named Project Manager-Corporate Restructuring Project; in 1999 was named Manager, Corporate Strategy & Development, and in 2002 was elected to his current position.

E. Follin Smith
Executive Vice President, Chief Financial Officer & Chief Administrative Officer, Constellation Energy
44, joined Constellation in 2001. Prior to this she was SVP and CFO of Armstrong Holdings, Inc. She spent 13 years with General Motors (GM), starting in the New York Treasurer's Office; other positions included Treasurer-GM of Canada Limited; VP of Finance for GMAC; Assistant Treasurer for GM; and CFO for GM's Delphi Chassis Systems division.

Michael J. Wallace
Executive Vice President, Constellation Energy and President, Constellation Generation Group
56, joined Constellation in 2002. Prior to this he was co-founder and Managing Director, Barrington Energy Partners, LLC, an energy industry strategic consulting firm. Previously he held several executive positions at Unicom/ComEd of Illinois. He was also ComEd's Chief Nuclear Officer, responsible for the operation of the company's 12 nuclear generating units at six power plant sites.

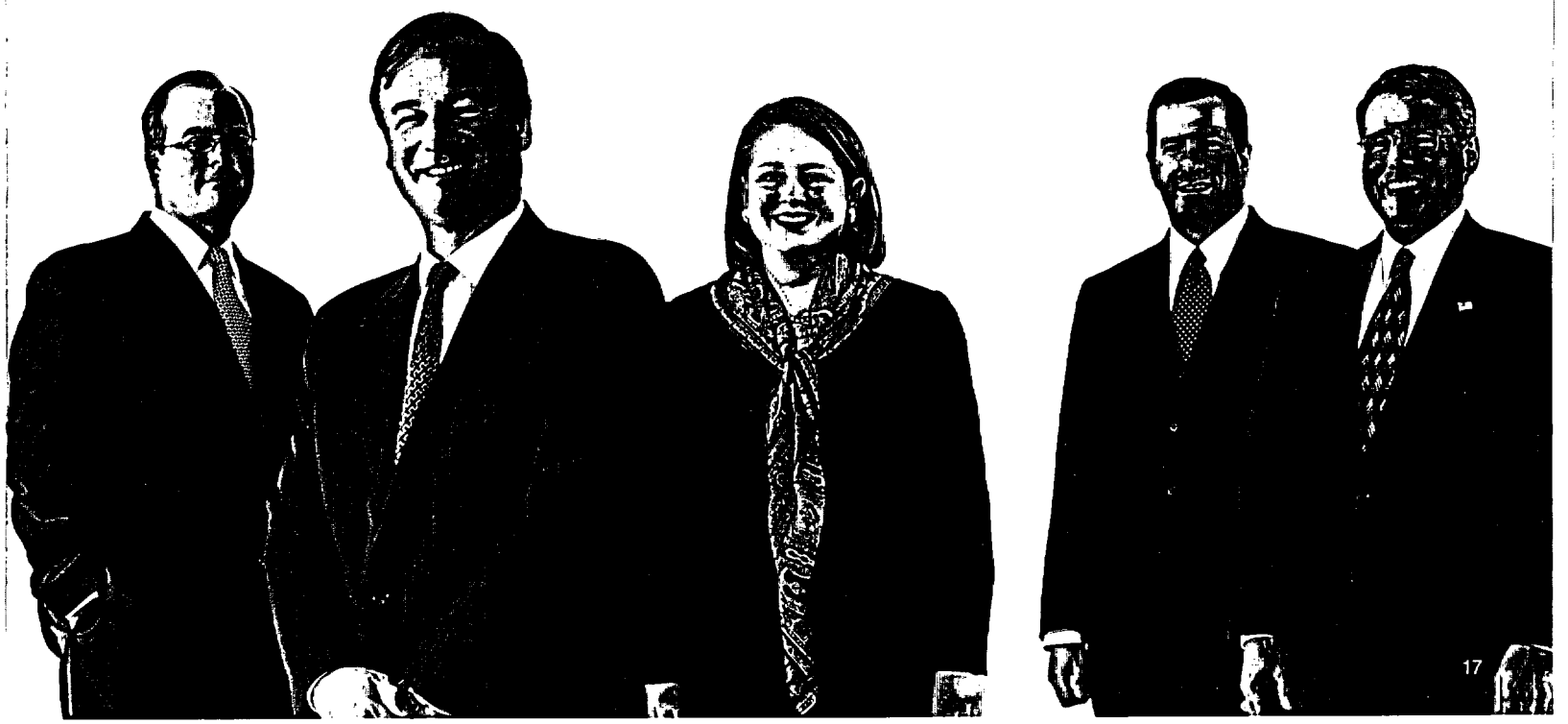
Mark P. Huston
Vice President, Corporate Strategy & Development

Mayo A. Shattuck III
Chairman, President & Chief Executive Officer

E. Follin Smith
Executive Vice President, Chief Financial Officer & Chief Administrative Officer

Marc L. Ugol
Senior Vice President, Human Resources

Michael J. Wallace
Executive Vice President, Constellation Energy and President, Constellation Generation Group



Understanding Our Form 10-K

One of our priorities at Constellation Energy is to provide you with clear, easy-to-read and easy-to-understand information about our company. We want you to know what we do, how we do it, and how we're doing at it.

So we're working to make our Form 10-K – our annual report required to be filed with the Securities and Exchange Commission – more welcoming and less complex.

This special section is intended to be a guide, describing some of what you can find in our Form 10-K, and where you can find it. Our complete Form 10-K follows this special section.

Breaking Down Our Form 10-K

The information contained in the Form 10-K is broken down into Parts, which are further broken down into Items. Our Form 10-K has four Parts:

Part I	In-depth descriptions of our businesses.
Part II	Our financial performance, the information in which investors are usually most interested.
Part III	Directs readers to our proxy statement for details on our Board of Directors and executive officers and their compensation, and information about our independent auditors and the fees we have paid them.
Part IV	A listing of exhibits, and certain executive and Board of Directors' signatures.

Over the next few pages, we provide summaries of some of the major topics included in Parts I and II, and where you can find them. We're doing that for Parts I and II because they contain the most detailed information about our business.

Part I: Our Businesses

Part I of our Form 10-K provides details about our businesses:

- **Our merchant energy business.**
- **Our regulated utility – Baltimore Gas and Electric Company.**
- **Our other nonregulated businesses.**

Also included is information about environmental matters, employees, properties, and executive officers.

Here's Where You Look in Part I			Highlights of What You'll Find
Page	Item	Section	
1-2	Business	Overview	– Company description and brief background. *We have a merchant energy business and a regulated utility.* – Operating segment details. *Our reportable operating segments are merchant energy, regulated electric, and regulated gas.*
3-9		Merchant Energy Business	– Business description. *We combine electric generating assets with the marketing and risk management of energy.* – Discussion of fuel sources we use to generate electricity. *We have a diversified portfolio of fuel sources that we use to generate electricity.* – Discussion of our competition. *Companies – of various sizes and levels of experience and financial and human resources.* – Merchant energy operating statistics for the last five years. *Our revenues and megawatt hours generated.*
9-13		Baltimore Gas and Electric Company	– Business description broken down between electric and gas. *Our electric service territory covers 2,300 square miles, and our gas service territory covers 800 square miles.* – Electric and gas operating statistics for the last five years. *Revenues by customer type, sales to our customers, and the number of our customers.*
13		Other Nonregulated Businesses	– Descriptions of our other nonregulated energy businesses. *Primarily heating and cooling system services we provide to residential, commercial, industrial and municipal customers.*
13-16		Environmental Matters	– Discussion of the environmental matters affecting the company. *We are subject to regulations concerning air quality, water quality, and disposal of hazardous substances.*
16		Employees	– Number of employees. *We had approximately 8,650 employees at year end 2003.*
17-19	Properties		– Generating plant location, ownership and size details. *We own more than 12,000 megawatts of generating capacity located strategically throughout the United States.* – Offices and facilities we own and lease. *Our corporate offices are in Baltimore, and we have plants and marketing offices throughout North America.*
19-20	Executive Officers of the Registrant		– Executive officers' names, ages, current positions and recent experience. *Our corporate officers have a diverse mix of energy, financial and other experience in competitive and regulated markets.*

Note: This special section is intended to be a guide, describing some of what you can find in our Form 10-K, and where you can find it. Our complete Form 10-K follows this special section.

Part II: Our Financial Performance

Part II contains management's discussion of our results of operations and financial condition. It compares 2003 results to 2002, and 2002 results to 2001. The sections in Part II include:

- **Introductory Items – the basics.**
- **Management's Discussion and Analysis – the context.**
- **Financial Statements – the numbers.**
- **Notes to the Financial Statements – the details.**

Introductory Items

The basics. Here's information about our common stock, prices and dividends, and historical financial data.

Here's Where You Look in Part II			Highlights of What You'll Find
Page	Item	Section	
21	Market for Registrant's Common Equity and Related Shareholder Matters		– Dividend information and quarterly dividend and stock prices for the last two years. *The price of our common stock – at the end of each of the four quarters in 2003 – ranged from $25.17 to $39.61. We declared a dividend of $1.04 per share in 2003, and increased our annual dividend rate to $1.14 per share in January 2004.*
22-23	Selected Financial Data		– Summary of operations and financial conditions of Constellation Energy and Baltimore Gas and Electric, and financial statistics for the last five years. *Our results show the success of the strategy we've implemented.*

Management's Discussion and Analysis

The context. Our management discusses in detail the financial results and condition of our company ... and the way we manage our business.

Here's Where You Look in Part II			Highlights of What You'll Find
Page	Item	Section	
24	Management's Discussion and Analysis of Financial Condition and Results of Operations	Introduction and Overview	– Overview of our company. *We're an energy company that conducts business mainly through our merchant energy business and our regulated utility.*
24-25		Strategy	– Discussion of our overall strategy. *We are pursuing a balanced strategy to distribute energy through our North American competitive supply activities and our regulated utility in Maryland.*
25-28		Business Environment	– Discussion of the business environment in which we operate – in general and in Maryland and other states – and how regulation, the weather, and other factors affect our business. *Energy markets continued to be volatile in 2003, and competition continues to evolve in Maryland and other states that have deregulated.*
29-31		Critical Accounting Policies	– Description of our accounting policies that are most complex and subjective in showing our financial condition and results. *These include revenue recognition/mark-to-market, evaluation of assets for impairment, and asset retirement obligations.*
32-33		Significant Events of 2003	– Discussion of the significant events in 2003 that affected our company. *These include workforce reduction costs, impairment losses, selling non-core assets, Hurricane Isabel, startup of our High Desert plant, our acquisitions, synthetic fuels tax credits, our standard-setting outage at Calvert Cliffs, and our dividend increase.*

Note: This special section is intended to be a guide, describing some of what you can find in our Form 10-K, and where you can find it. Our complete Form 10-K follows this special section.

Here's Where You Look in Part II			Highlights of What You'll Find
Page	Item	Section	
34-48		Results of Operations	The detailed discussion of our earnings: – Our overall net income. *Changes in accounting principles reduced our net income by $198.4 million in 2003, while gains from selling non-core assets increased our net income by $166.7 million in 2002–including the effect of these and other special items, our overall net income for 2003 was $277.3 million, a decrease of $248.3 million from 2002.* – Our net income for our merchant energy business. *Changes in accounting principles reduced our merchant energy business net income by $198.4 million in 2003, resulting in a $132.6 million decrease from 2002.* – Our net income for our regulated electric and gas businesses. *Our regulated electric business net income for 2003 was $107.5 million, an increase of $8.2 million from 2002; and our regulated gas business net income for 2003 was $43.0 million, an increase of $11.9 million from 2002.* – Our net income from our other nonregulated businesses. *Net income from our other nonregulated businesses during 2003 was $12.2 million, compared with $148.0 million in 2002–mainly the result of $169.1 million in gains on non-core assets we sold in 2002.*
49-51		Financial Condition	– Cash flow details. *Cash provided by our operations was $1.1 billion in 2003, a $60 million increase from 2002.* – Security ratings for Constellation Energy and Baltimore Gas and Electric. *All our security ratings are solid investment grade, with stable outlooks.*
51-54		Capital Resources	– Capital requirements for the last three years and an estimate for 2004 and 2005. *We're estimating that we'll need $760 million in capital for 2004 and $650 million to $750 million in 2005 to fund construction and improvements to our existing facilities and plants, and to comply with various environmental regulations.* – How we expect to fund our capital requirements. *Funding for the expansion of our merchant energy business is expected from internally generated funds and other available sources. We expect to fund acquisitions with a mixture of debt and equity, with our overall goal of maintaining a strong investment grade credit profile.* – Committed amounts over the next five years and beyond. *We describe our contractual and contingent obligations.*
54-58		Market Risk	– Discussion of our market risks and how we manage them. *Our risk factors include interest rates, commodity prices, competition, operational reliability of generating plants, creditworthiness of our counterparties, and equity prices.*

Our Financial Statements

The numbers. We provide separate financial statements for Constellation Energy and Baltimore Gas and Electric. This section also includes our management and auditors reports on our financial information.

Here's Where You Look in Part II			Highlights of What You'll Find
Page	Item	Section	
59	Financial Statements and Supplementary Data	Report of Management	– Management's report on how the financial statements are prepared–signed by Chairman of the Board, President and Chief Executive Officer Mayo A. Shattuck III and by Executive Vice President, Chief Financial Officer and Chief Administrative Officer E. Follin Smith. *Our management accepts responsibility for the information and representations in our financial statements.*
59		Report of Independent Auditors	– External audit report of PricewaterhouseCoopers LLP. *Our independent auditors state their opinion that our consolidated financial statements present fairly, in all material respects, the financial condition of our company.*

Note: This special section is intended to be a guide, describing some of what you can find in our Form 10-K, and where you can find it. Our complete Form 10-K follows this special section.

Our Financial Statements *(continued)*

Here's Where You Look in Part II			Highlights of What You'll Find
Page	Item	Section	
60		Consolidated Statements of Income	– Revenue, expenses, income and earnings for the last three years. *Taking out the effect of a $166.7 million net after-tax gain on sales of investments and other assets in 2002, and the $198.4 million after-tax charge for the cumulative effects of changes in accounting principles, our earnings – excluding these and other special items – grew nearly 10 percent in 2003.*
61-62		Consolidated Balance Sheets	– Assets, and total liabilities and equity for the last two years. *Our total assets were $15.8 billion at December 31, 2003.*
63		Consolidated Statements of Cash Flows	– Cash flows from operating, investing and financing activities for the last three years. *Our net cash provided by operating activities increased from $573.3 million in 2001 to $1.02 billion in 2002 to $1.08 billion in 2003.*
64		Consolidated Statements of Common Shareholders' Equity and Comprehensive Income	– Changes in common stock, retained earnings, and other comprehensive income for the last three years. *We declared $172.8 million in dividends during 2003, and our retained earnings were $2.1 billion at year end.*
65-66		Consolidated Statements of Capitalization	– Long-term debt, preference stock and common shareholders' equity details for the last two years. *At December 31, 2003, our total capitalization was $9.5 billion – $5.0 billion in long-term debt, $113.4 million in minority interests, $190.0 million in preference stock, and $4.1 billion in common shareholders' equity.*
67-70		Baltimore Gas and Electric Financial Statements	– Consolidated Statements of Income, Consolidated Statements of Comprehensive Income, Consolidated Balance Sheets, and Consolidated Statements of Cash Flows. *We include financial statements for BGE because it has publicly traded debt and is a separate registrant required to file with the SEC.*

Notes to Our Financial Statements

The details. We explain the processes, events, actions, projects, issues and specifics that produce the amounts reflected in our financial statements.

Here's Where You Look in Part II			Highlights of What You'll Find
Page	Item	Section	
71-82	Notes to Consolidated Financial Statements	Note 1 Significant Accounting Policies	– Accounting methods that we use, and how they're applied throughout our businesses. – Accounting standards issued.
83-87		Note 2 Workforce Reduction, Impairment Losses, Contract Termination, and Other Events	– Workforce reduction, impairment losses and other events – pre-tax and after-tax amounts for the last three years.
87-88		Note 3 Information by Operating Segment	– Revenue, expense, net income and other financial information for our reportable operating segments and other nonregulated businesses for the last three years.

Note: This special section is intended to be a guide, describing some of what you can find in our Form 10-K, and where you can find it. Our complete Form 10-K follows this special section.

Here's Where You Look in Part II			Highlights of What You'll Find
Page	Item	Section	
89-90		Note 4 Investments	– Real estate, power project, and financial investments for the last two years.
91		Note 5 Intangible Assets	– Goodwill and intangible assets subject to amortization.
92-93		Note 6 Regulatory Assets (net)	– Regulatory assets for the last two years.
93-97		Note 7 Pension, Postretirement, Other Postemployment, and Employee Savings Plan Benefits	– Pension and postretirement benefits–obligation, asset, funded status, and assumption details about our employee benefit plans for the last two years. – Employee savings plan information and company-matching contributions.
98		Note 8 Short-Term Borrowings	– Short-term bank loans, commercial paper outstanding, and available bank lines of credit for Constellation Energy, Baltimore Gas and Electric, and our nonregulated businesses.
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Note: This special section is intended to be a guide, describing some of what you can find in our Form 10-K, and where you can find it. Our complete Form 10-K follows this special section.

Glossary

aggregator–a company or agent that combines the energy needs of multiple customers and then buys or provides the energy and services needed.

British thermal unit (Btu)–the basic unit used to measure natural gas; the amount of natural gas needed to raise the temperature of one pound of water by one degree Fahrenheit.

competitive supply business–our growth engine; the portion of our business that provides energy and value-added services to wholesale and retail customers located in competitive markets.

dekatherm–a measurement of natural gas; ten therms or one million Btu.

deregulation–in the energy industry, the process by which regulated markets become competitive markets, giving customers the opportunity to choose their supplier.

distribution–the delivery of energy to retail customers, including homes, businesses, office buildings and industrial facilities.

Emerging Issues Task Force (EITF)–a group of financial professionals that advises the Financial Accounting Standards Board (FASB) about standards for reporting new transactions that may be unique and complex.

Federal Energy Regulatory Commission (FERC)–the U.S. agency that regulates interstate energy activities.

Financial Accounting Standards Board (FASB)–an independent, private sector organization that is recognized by the Securities and Exchange Commission and relied upon to establish and improve standards of financial accounting and reporting.

full requirements service–a product offering that handles all of a customer's energy needs through a combined service that can include generating or buying energy, managing load and power purchase agreements, scheduling delivery, managing risk, settling accounts, and other related services.

generating capacity–the amount of electricity that can be produced by a specified generating plant or utility.

generation–the process of transforming other forms of energy–coal, natural gas, uranium, oil, wind, water, and sun–into electricity.

hydrocarbons–fuels–including oil, natural gas and coal–used to produce energy.

independent system operator–a federally regulated organization that manages regional transmission lines to deliver electricity.

load serving–the process of providing wholesale customers with the energy they need to serve their retail customers.

megawatt–one million watts of electricity; enough electricity to light 10,000 100-watt light bulbs.

megawatt hour–one million watts of electricity consumed over one hour; enough electricity to keep 10,000 100-watt light bulbs lit for one hour.

merchant energy business–our nonregulated business that combines generation from our power plants and energy we purchase with marketing and other services to provide energy solutions to meet the needs of customers throughout North America.

nonregulated business–the portion of our business that operates in competitive, or deregulated, markets.

nuclear decommissioning trust fund–a federally mandated fund set up to ensure that nuclear power plant owners put aside enough money to pay for cleaning up and dismantling the plants at the end of their useful lives.

Nuclear Regulatory Commission–the U.S. agency that regulates commercial nuclear power plants and the civilian use of nuclear materials.

open access–the mandate allowing companies fair use of other companies' transmission and distribution power lines at cost-based fees.

origination–the initiation of wholesale energy purchases and sales that may include value-added services along with the energy.

physical delivery activity–the completion of an energy sale by the actual delivery of the energy to a customer.

regional transmission organization (RTO)–a group of companies with responsibility for the planning and use of power transmission lines in a geographic region.

regulated business–the portion of our business whose primary operations and prices are set and controlled by the rules and activities of a governmental agency.

retail market–the market in which energy is sold directly to the customers who use it.

Standard Offer Service–in Maryland, the obligation of a utility–such as Baltimore Gas and Electric–to supply electricity as the provider of last resort (POLR) for those customers who have not chosen an alternate supplier.

transmission–the sending of electricity at high voltage, usually on lines running along high towers, from generating plants to substations, where it is then reduced to a lower voltage that is delivered to homes, businesses, office buildings and industrial facilities.

value at risk (VaR)–a statistical measure that helps evaluate risk by showing how much the value of mark-to-market assets or liabilities may change under various circumstances.

watt–the basic unit used to measure electricity; for example, a 100-watt light bulb requires more electricity and provides brighter light than a 60-watt light bulb.

wholesale market–the market in which energy is sold in large blocks to other utilities, distribution companies, electric co-operatives, municipalities, and power marketers, who then sell or distribute the energy to others.

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended **DECEMBER 31, 2003**

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

MARYLAND

(States of incorporation)

750 E. PRATT STREET BALTIMORE, MARYLAND 21202

(Address of principal executive offices) (Zip Code)

410-783-2800

(Registrants' telephone number, including area code)

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

Title of each class	Name of Each Exchange on Which Registered
Constellation Energy Group, Inc. Common Stock—Without Par Value	New York Stock Exchange, Inc. Chicago Stock Exchange, Inc. Pacific Exchange, Inc.
6.20% Trust Preferred Securities ($25 liquidation amount per preferred security) issued by BGE Capital Trust II, fully and unconditionally guaranteed, based on several obligations, by Baltimore Gas and Electric Company	New York Stock Exchange, Inc.

SECURITIES REGISTERED PURSUANT TO SECTION 12(G) OF THE ACT:
Not Applicable

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months, and (2) have been subject to such filing requirements for the past 90 days. Yes ☒ No ☐.

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrants' knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

Indicate by check mark whether Constellation Energy Group, Inc. is an accelerated filer Yes ☒ No ☐.
Indicate by check mark whether Baltimore Gas and Electric Company is an accelerated filer Yes ☐ No ☒.

Aggregate market value of Constellation Energy Group, Inc. Common Stock, without par value, held by non-affiliates as of June 30, 2003 was approximately $5,698,266,202 based upon New York Stock Exchange composite transaction closing price.

CONSTELLATION ENERGY GROUP, INC. COMMON STOCK, WITHOUT PAR VALUE 168,103,732 SHARES OUTSTANDING ON FEBRUARY 27, 2004.

DOCUMENTS INCORPORATED BY REFERENCE

Part of Form 10-K	Document Incorporated by Reference
III	Certain sections of the Proxy Statement for Constellation Energy Group, Inc. for the Annual Meeting of Shareholders to be held on May 21, 2004.

Baltimore Gas and Electric Company meets the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K and is therefore filing this Form in the reduced disclosure format.

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Forward Looking Statements

We make statements in this report that are considered forward looking statements within the meaning of the Securities Exchange Act of 1934. Sometimes these statements will contain words such as "believes," "anticipates," "expects," "intends," "plans," and other similar words. We also disclose non-historical information that represents management's expectations, which are based on numerous assumptions. These statements and projections are not guarantees of our future performance and are subject to risks, uncertainties, and other important factors that could cause our actual performance or achievements to be materially different from those we project. These risks, uncertainties, and factors include, but are not limited to:

- the timing and extent of changes in commodity prices and volatilities for energy and energy related products including coal, natural gas, oil, electricity, and emission allowances,
- the timing and extent of deregulation of, and competition in, the energy markets in North America, and the rules and regulations adopted on a transitional basis in those markets,
- the conditions of the capital markets, interest rates, availability of credit, liquidity, and general economic conditions, as well as Constellation Energy Group's (Constellation Energy) and Baltimore Gas and Electric Company's (BGE) ability to maintain their current credit ratings,
- the effectiveness of Constellation Energy's and BGE's risk management policies and procedures and the ability and willingness of our counterparties to satisfy their financial and performance commitments,
- the liquidity and competitiveness of wholesale markets for energy commodities,
- operational factors affecting commercial operations of our generating facilities (including nuclear facilities) and BGE's transmission and distribution facilities, including catastrophic weather related damages, unscheduled outages or repairs, unanticipated changes in fuel costs or availability, unavailability of gas transportation or electric transmission services, workforce issues, terrorism, liabilities associated with catastrophic events, and other events beyond our control,
- the inability of BGE to recover all its costs associated with providing electric retail customers service during the electric rate freeze period,
- the effect of weather and general economic and business conditions on energy supply, demand, and prices,
- regulatory or legislative developments that affect deregulation, transmission or distribution rates and revenues, demand for energy, or increases in costs, including costs related to nuclear power plants, safety, or environmental compliance,
- the actual outcome of uncertainties associated with assumptions and estimates using judgment when applying critical accounting policies and preparing financial statements, including factors that are estimated in determining the fair value of energy contracts, such as the ability to obtain market prices and in the absence of verifiable market prices the appropriateness of models and model inputs (including, but not limited to, estimated contractual load obligations, unit availability, forward commodity prices, interest rates, correlation and volatility factors),
- changes in accounting principles or practices,
- the ability to attract and retain customers in our competitive supply activities and to adequately forecast their energy usage,
- losses on the sale or write down of assets due to impairment events or changes in management intent with regard to either holding or selling certain assets, and
- cost and other effects of legal and administrative proceedings that may not be covered by insurance, including environmental liabilities.

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

Changes may occur after that date, and neither Constellation Energy nor BGE assume responsibility to update these forward looking statements.

PART I

Item 1. Business

Overview

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

Constellation Energy was incorporated in Maryland on September 25, 1995. On April 30, 1999, Constellation Energy became the holding company for BGE and its subsidiaries through a share exchange. References in this report to "we" and "our" are to Constellation Energy and its subsidiaries, collectively. References in this report to the "utility business" are to BGE.

Our merchant energy business is a competitive provider of energy solutions for large customers in North America. It has electric generation assets located in various regions of the United States and provides energy solutions to meet customers' needs. Our merchant energy business focuses on serving the full energy and capacity requirements (load-serving) of, and providing other energy risk management services for various customers, such as utilities, municipalities, cooperatives, retail aggregators, and commercial and industrial customers.

Our merchant energy business includes:

- a generation operation that owns, operates, and maintains fossil, nuclear, and hydroelectric generating facilities and interests in qualifying facilities, fuel processing facilities and power projects in the United States,
- a marketing and risk management operation that provides energy products and services to wholesale customers,
- an electric and gas retail operation that provides energy services to commercial and industrial customers, and
- a generation and consulting services operation.

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

Our other nonregulated businesses:

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

In addition, we own several investments that we do not consider to be core operations. These include financial investments, real estate projects, and interests in a Latin American power distribution project and in a fund that holds interests in two South American energy projects.

For a discussion of recent events that have impacted us, please refer to *Item 7. Management's Discussion and Analysis—Significant Events of 2003* section. For a discussion of our strategy, please refer to *Item 7. Management's Discussion and Analysis—Strategy* section. For a discussion of the seasonality of our business, please refer to *Item 7. Management's Discussion and Analysis—Business Environment* section.

Constellation Energy maintains a website at constellation.com where copies of our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and any amendments may be obtained free of charge. These reports are posted on our website the same day they are filed with the SEC. The website address for BGE is bge.com. Both website addresses are inactive textual references and the contents of these websites are not part of this Form 10-K.

In addition, the website for Constellation Energy includes copies of our Corporate Governance Guidelines, Principles of Business Integrity, Corporate Compliance Program and Insider Trading Policy, and the charters for the Audit, Compensation and Nominating and Corporate Governance Committees of the Board of Directors. Copies of each of these documents may be printed from the website or may be obtained from Constellation Energy upon written request to the Corporate Secretary.

The Principles of Business Integrity is a code of ethics which applies to all of our directors, officers, and employees, including the chief executive officer, chief financial officer, and chief accounting officer. We will post any amendments to, or waivers from, the Principles of Business Integrity applicable to our chief executive officer, chief financial officer, or chief accounting officer on our website.

Operating Segments

The percentages of revenues, net income, and assets attributable to our operating segments are shown in the tables below. We present information about our operating segments, including certain special items, in *Note 3 to Consolidated Financial Statements.*

	Unaffiliated Revenues			
	Merchant Energy	Regulated Electric	Regulated Gas	Other Nonregulated
2003	67%	20%	7%	6%
2002	35	42	12	11
2001	16	53	17	14

	Net Income (1)			
	Merchant Energy	Regulated Electric	Regulated Gas	Other Nonregulated
2003	66%	23%	9%	2%
2002	47	19	6	28
2001	113	62	45	(120)

	Total Assets			
	Merchant Energy	Regulated Electric	Regulated Gas	Other Nonregulated
2003	68%	22%	7%	3%
2002	65	24	7	4
2001	59	25	8	8

(1) Excludes cumulative effects of changes in accounting principles as discussed in more detail in *Item 8. Financial Statements and Supplementary Data.*

Merchant Energy Business

Introduction

Our merchant energy business integrates electric generation assets with the marketing and risk management of energy and energy-related commodities, allowing us to manage energy price risk over geographic regions and over time. Constellation Power Source, our wholesale marketing and risk management operation, dispatches the energy from our generating facilities, manages the risks associated with selling the output and obtaining fuels, and structures transactions to meet customers' energy and risk management requirements. Constellation NewEnergy, our electric and gas retail operation, provides energy services to commercial and industrial customers. Generation capacity supports these marketing operations by providing a source of reliable power supply that provides a physical hedge for some of our load-serving activities.

Our merchant energy business:

- provided service to distribution utilities, municipalities, and commercial and industrial customers with approximately 24,000 megawatts (MW) of peak load in the aggregate during 2003,
- provided approximately 195,000 million British Thermal Units (mmBTUs) of natural gas to commercial and industrial customers during 2003, and
- owns approximately 12,030 MW of generation capacity.

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

- Mid-Atlantic Fleet—our fossil, nuclear, and hydroelectric generating facilities and load-serving activities in the PJM Interconnection (PJM) region for which the output is primarily used to serve BGE. This also includes active portfolio management of the generating assets and associated physical and financial arrangements.
- Plants with Power Purchase Agreements—our generating facilities with long-term power purchase agreements, including our Nine Mile Point Nuclear Station (Nine Mile Point), Oleander, University Park, and High Desert generating facilities.
- Competitive Supply—our wholesale marketing and risk management operation that provides energy products and services to distribution utilities and other wholesale customers. We also provide electric and gas energy services to retail commercial and industrial customers.
- Other—our investments in qualifying facilities and domestic power projects and our generation and consulting services.

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

Mid-Atlantic Fleet

We own 6,379 MW of fossil, nuclear and hydroelectric generation capacity in the PJM region. The output of these plants is managed by our wholesale marketing and risk management operation and is hedged through a combination of power sales to wholesale and retail market participants.

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

Our merchant energy business provides standard offer service to BGE as discussed in the *Baltimore Gas and Electric Company—Standard Offer Service* section. Our merchant energy business meets the load-serving requirements of this contract using the output from the Mid-Atlantic Fleet and from purchases in the wholesale market. For 2003, the peak load supplied to BGE was approximately 5,270 MW.

Plants with Power Purchase Agreements

We own 3,360 MW of nuclear and natural gas/oil generation capacity with power purchase agreements for their output. Our facilities with power purchase agreements consist of:

- the Nine Mile Point facility,
- the High Desert Power Project, which commenced operations in early 2003,
- the Oleander project, which commenced operations in mid-2002, and
- the University Park project, which commenced operations in mid-2001.

We purchased 100% of Nine Mile Point Unit 1 (609 MW) and 82% of Unit 2 (941 MW) in November 2001. The remaining interest in Nine Mile Point Unit 2 is owned by a subsidiary of the Long Island Power Authority. Unit 1 entered service in 1969 and Unit 2 in 1988. Nine Mile Point is located within the New York Independent System Operator (NYISO) region.

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

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

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

The license on Nine Mile Point's Unit 1 expires in 2009 and in 2026 on Unit 2. We have commenced a license extension initiative for both units with the objective of obtaining up to 20 years of additional operations. We expect to submit the license extension application to the NRC in the spring of 2004.

The High Desert Power Project has a long-term power sales agreement with the California Department of Water Resources (CDWR). The contract is a "tolling" structure, under which the CDWR pays a fixed amount of $12.1 million per month and provides CDWR the right, but not the obligation, to purchase power from the project at a price linked to the variable cost of production. During the term of the contract, which runs until December 2010, the project will provide energy exclusively to the CDWR.

We have sold portions of the output of the Oleander and University Park facilities ranging from 50% to 100% under tolling contracts for terms ending in 2005 through 2009. Under these tolling contracts, our respective counterparties will pay a fixed amount per month and have the right, but not the obligation, to purchase power from us at prices linked to the variable fuel and other costs of production.

On November 25, 2003, we announced an agreement with Rochester Gas & Electric (RG&E) to acquire the 495 megawatt R.E. Ginna Nuclear Power Plant (Ginna) located north of Rochester, New York. The transaction is contingent upon regulatory approvals including license extension. The acquisition includes a long-term unit contingent power purchase agreement where we will sell 90% of the plant's output and capacity to RG&E for 10 years at an average price of $44.00 per MWH. The remaining 10% of the plant's output will be managed by our wholesale marketing and risk management and will be sold into the wholesale market.

Competitive Supply

We are a leading supplier of energy products and services in North America to wholesale customers and retail commercial and industrial customers. Our competitive supply activities include 2,015 MW from our Rio Nogales, Holland Energy, Big Sandy, and Wolf Hills natural gas-fired generating facilities. These four facilities are not sold forward under long-term agreements, and their output is used to serve customer requirements.

Origination of Structured Transactions

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

These activities typically occur in regional markets in which end user customers' electricity rates have been deregulated and thereby separated from the cost of generation supply. These markets include:

- the New England, New York, and Mid-Atlantic regions,
- Texas,
- the Mid-West region,
- the West region, and
- certain areas of Canada.

Contracts with these customers generally extend from one to ten years, but some can be longer. We currently have approximately 22,800 MW of load under contract for 2004.

In 2003, we acquired Blackhawk Energy Services and Kaztex Energy Management and in 2002, we acquired NewEnergy and Alliance. These acquisitions expand our business in the competitive supply market by providing electricity, natural gas, transportation, and other energy related services to retail commercial and industrial customers throughout North America.

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

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

Portfolio Management

Our wholesale marketing and risk management operation actively uses energy and energy-related commodities in order to manage our portfolio of energy purchases and sales to customers through structured transactions. As part of our risk management activities we trade power and gas to enable price discovery and facilitate the hedging of our load-serving and other risk management products and services. Within our trading function we allow limited risk-taking activities for profit. These activities are actively managed through daily value at risk and liquidity position limits. We discuss value at risk in more detail in *Item 7. Management's Discussion and Analysis—Market Risk.*

These activities involve the use of a variety of instruments, including:

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

Active portfolio management allows our wholesale marketing and risk management operation the ability to:

- manage and hedge its fixed-price purchase and sale commitments,
- provide fixed-price commitments to customers and suppliers,
- reduce exposure to the volatility of cash market prices, and
- hedge fuel requirements at our generation facilities.

Other

We hold up to a 50% ownership interest in 25 operating energy projects that consist of electric generation (primarily relying on alternative fuel sources), fuel processing, or fuel handling facilities and are either qualifying facilities under the Public Utility Regulatory Policies Act of 1978 or otherwise exempt from, or not subject to, the Public Utility Holding Company Act of 1935. In addition, we own 100% of a geothermal electric generating facility in Hawaii. Each electric generating plant sells its output to a local utility under long-term contracts.

We also provide the following services:

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

Fuel Sources

Our power plants use diverse fuel sources. Our fuel mix based on capacity owned at December 31, 2003 and our generation based on actual output by fuel type in 2003 were as follows:

Fuel	Capacity Owned	Generation
Nuclear	27%	50%
Coal	24	36
Natural Gas	31	7
Oil	6	1
Renewable and Alternative (1)	3	4
Dual (2)	9	2

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

(2) Switches between natural gas and oil.

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

Nuclear

The output at Calvert Cliffs Nuclear Power Plant (Calvert Cliffs) over the past five years has been:

	Generation MWH	Capacity Factor
2003	13,653,338	93%
2002	12,087,408	82
2001	13,648,932	92
2000	13,826,046	93
1999	13,309,306	91

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

	Generation MWH*	Capacity Factor
2003	12,169,637	90%
2002	11,727,567	87
2001	11,613,519	86
2000	11,243,095	83
1999	10,766,425	79

*represents our proportionate ownership interest

The supply of fuel for nuclear generating stations includes the:

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

Uranium: We have under contract sufficient quantities of uranium (concentrates and uranium hexafluoride) to meet 100% of both Calvert Cliffs' and Nine Mile Point's requirements through 2004, 45% for both plants in 2005, 60% for both plants in 2006, and 25% for both plants in 2007. In late 2003, the federally designated Russian export agent responsible for nuclear fuel terminated their contract with one of our key uranium hexafluoride suppliers located in the United States. This action will likely impact uranium hexafluoride deliveries from this supplier throughout the term of our agreement. Prices have increased due to this event and will adversely impact our future costs of uranium hexafluoride. The uranium hexafluoride that was scheduled to be delivered from this supplier in 2004 represents approximately 27% of our requirements for that year. We are currently evaluating our options to acquire alternate uranium hexafluoride supplies to meet our requirements.

Conversion: We have contractual commitments providing for the conversion of all of our uranium concentrates into uranium hexafluoride for Calvert Cliffs and Nine Mile Point through 2004. We do not have requirements for conversion beyond 2004 because we currently do not expect to purchase uranium concentrates beyond 2004.

Enrichment: We have contractual commitments that provide 100% of Calvert Cliffs' and Nine Mile Point's uranium enrichment requirements through 2006 and 25% of these requirements for both plants in 2007 and 2008.

Fuel Assembly Fabrication: We have contracted for the fabrication of fuel assemblies for reloads required through 2013 at Calvert Cliffs and through 2008 for Nine Mile Point.

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

Storage of Spent Nuclear Fuel—Federal Facilities

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

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

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

Storage of Spent Nuclear Fuel—On-Site Facilities

Calvert Cliffs has a license from the NRC to operate an on-site independent spent fuel storage installation that expires in 2012. We have storage capacity at Calvert Cliffs that will accommodate spent fuel from operations through 2008. In addition, we can expand our temporary storage capacity at Calvert Cliffs to meet future requirements until approximately 2025. Currently, Nine Mile Point does not have independent spent fuel storage capacity. Rather, Nine Mile Point's Unit 1 has sufficient storage capacity within the plant until the end of its current operating license in 2009. If license renewal is obtained, independent spent fuel storage capability will need to be developed. Nine Mile

Point's Unit 2 has sufficient storage capacity within the plant until 2012. After that time independent spent fuel storage capability may need to be developed.

Cost for Decommissioning Uranium Enrichment Facilities
The Energy Policy Act of 1992 contains provisions requiring domestic nuclear utilities to contribute to a fund for decommissioning and decontaminating uranium enrichment facilities that had been operated by DOE. These contributions are generally payable over a 15-year period with escalation for inflation and are based upon the amount of uranium enriched by DOE for each utility through 1992. The 1992 Act provides that these costs are recoverable through utility service rates. BGE is solely responsible for these costs as they relate to Calvert Cliffs. The sellers of the Nine Mile Point plant and a subsidiary of the Long Island Power Authority are responsible for the costs relating to the Nine Mile Point plant.

Cost for Decommissioning
We are obligated to decommission our nuclear plants at the time these plants cease operation. Both Calvert Cliffs and Nine Mile Point are required by the NRC to demonstrate reasonable assurance that funds will be available to decommission the sites. When BGE transferred all of its nuclear generating assets to our merchant energy business, it also transferred the trust fund established to pay for decommissioning Calvert Cliffs. At December 31, 2003, the trust fund assets were $284.9 million.

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

The sellers of Nine Mile Point transferred a $441.7 million decommissioning trust fund at the time of sale. In return, Nine Mile Point assumed all liability for the costs to decommission Unit 1 and 82% of the cost to decommission Unit 2. We believe that this amount is adequate to cover our responsibility for decommissioning Nine Mile Point to a greenfield status (restoration of the site so that it substantially matches the natural state of the surrounding properties and the site's intended use). At December 31, 2003, the Nine Mile Point trust fund assets were $451.2 million.

Upon the closing of the Ginna acquisition, the seller will transfer approximately $202 million in decommissioning funds. In return, we will assume all liability for the costs to decommission the unit. The amount of the decommissioning trust fund transfer is subject to regulatory approval. We believe that this transfer will be sufficient to cover our responsibility for decommissioning Ginna to a greenfield status.

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

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

Coal deliveries to these facilities are made by rail and barge. The primary source of coal we use is produced from mines located in central and northern Appalachia. During 2003, we expanded our coal sources including restructuring our rail contracts, increasing the range of coals we can consume, adding synthetic fuel as an alternate source, and finding potential other coal supply sources including shipments from areas including Columbia, Venezuela, and South Africa.

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

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

All of our requirements reflect historical levels. The actual fuel quantities required can vary substantially from historical levels depending upon the relationship between energy prices and fuel costs, weather conditions, and operating requirements.

Gas

We purchase natural gas, storage capacity, and transportation, as necessary, for electric generation at certain plants. Some of our gas-fired units can use residual fuel oil or distillates instead of gas. Gas is purchased under contracts with suppliers on the spot market and forward markets, including financial exchanges and bilateral agreements. The actual fuel quantities required can vary substantially from year to year depending upon the relationship between energy prices and fuel costs, weather conditions, and operating requirements. However, we believe that we will be able to obtain adequate quantities of gas to meet our requirements.

Oil

Under normal burn practices, our requirements for residual fuel oil (No. 6) amount to approximately 1.5 million to 2.0 million barrels of low-sulfur oil per year. Deliveries of residual fuel oil are made from the suppliers' Baltimore Harbor marine terminal for distribution to the various generating plant locations. Also, based on normal burn practices, we require approximately 5.0 million to 6.0 million gallons of distillates (No. 2 oil and kerosene) annually, but these requirements can vary substantially from year to year depending upon the relationship between energy prices and fuel costs, weather conditions, and operating requirements. Distillates are purchased from the suppliers' Baltimore truck terminals for distribution to the various generating plant locations. We have contracts with various suppliers to purchase oil at spot prices, and for future delivery, to meet our requirements.

Competition

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

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

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

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

Increased competition that resulted from some of these initiatives in several states contributed in some instances to a reduction in electricity prices and put pressure on electric utilities to lower their costs, including the cost of purchased electricity. Some states that were considering deregulation have slowed their plans or postponed consideration of deregulation. In addition, other states are reconsidering deregulation.

We believe there is adequate growth potential in the current deregulated market. However, in response to regional market differences and to promote competitive markets, the Federal Energy Regulatory Commission (FERC) proposed initiatives promoting the formation of Regional Transmission Organizations and a standard market design. If approved, these market changes could provide additional opportunities for our merchant energy business.

As the economy continues to recover and the market for commercial and industrial supply continues to grow, we have experienced increased competition in our retail commercial and industrial supply activities. The increase in retail competition may affect the margins that we will realize from our customers. However, we believe that our experience and expertise in assessing and managing risk will help us to remain competitive during volatile or otherwise adverse market circumstances.

Merchant Energy Operating Statistics

	2003	2002	2001	2000	1999
Revenues *(In millions)*					
Mid-Atlantic Fleet	**$1,774.5**	$1,415.1	$1,379.2	$ 731.7	$ —
Plants with Power Purchase Agreements	**620.0**	456.4	70.8	—	—
Competitive Supply—Accrual Revenues	**5,157.1**	623.4	59.2	—	—
—Mark-to-Market Revenues	**51.4**	238.1	175.8	151.5	147.7
Other	**45.1**	56.4	80.5	142.5	129.6
Total Revenues	**$7,648.1**	$2,789.4	$1,765.5	$1,025.7	$277.3
Generation *(In millions)*—MWH	**51.6**	44.7	37.4	18.8	1.3

Operating statistics do not reflect the elimination of intercompany transactions.

Baltimore Gas and Electric Company

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

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

BGE's electric and gas revenues come from many customers—residential, commercial, and industrial. In 2003, BGE's largest electric customer provided approximately four percent of BGE's total electric revenues. In 2003, BGE's largest gas customer provided approximately one percent of BGE's total gas revenues.

Electric Business

Electric Regulatory Matters and Competition

Deregulation

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

- All customers can choose their electric energy supplier. BGE provides fixed price standard offer service over various time periods for different classes of customers that do not select an alternative supplier until June 30, 2006.
- While BGE does not sell electric commodity to all customers in its service territory, BGE does deliver electricity to all customers and provides meter reading, billing, emergency response, regular maintenance, and balancing services.
- BGE provides market rate standard offer service for those commercial and industrial customers who are no longer eligible for fixed price standard offer service.
- BGE residential base rates will not change before July 2006. While total residential base rates remain unchanged over the initial transition period (July 1, 2000 through June 30, 2006), annual standard offer service rate increases are offset by corresponding decreases in the competitive transition charge (CTC) that BGE receives from its customers.
- Commercial and industrial customers have several service options that will fix electric energy rates through June 30, 2004 and competitive transition charges through June 30, 2006.
- BGE transferred, at book value, its generating assets and related liabilities to the merchant energy business. At December 31, 2003, BGE remains contingently liable for the $269.8 million outstanding balance for liabilities transferred to the merchant energy business.

Standard Offer Service

Our wholesale marketing and risk management operation provides BGE with 100% of the energy and capacity required to meet its commercial and industrial standard offer service obligations through June 30, 2004, and 100% of the energy and capacity required to meet its residential standard offer service obligations through June 30, 2006. BGE will obtain its supply for standard offer service to its commercial and industrial customers beginning July 1, 2004, and to its residential customers beginning July 1, 2006, through a competitive wholesale bidding process as discussed in the *Standard Offer Service—Provider of Last Resort (POLR)* section on the next page.

Beginning July 1, 2002, the fixed price standard offer service rate ended for certain of our large commercial and industrial customers. As a result, the majority of these customers purchase their electricity

from alternate suppliers, including subsidiaries of Constellation Energy. The remaining large commercial and industrial customers that continue to receive their electric supply from BGE are charged market-based standard offer service rates through June 30, 2004.

Beginning July 1, 2004, all other commercial and industrial customers that receive their electric supply from BGE will be charged market-based standard offer service rates. Beginning July 1, 2006, BGE's current obligation to provide fixed price standard offer service to residential customers ends and all residential customers that receive their electric supply from BGE will be charged market-based standard offer service rates.

Standard Offer Service—Provider of Last Resort (POLR)

In April 2003, the Maryland PSC approved a settlement agreement reached by BGE and parties representing customers, industry, utilities, suppliers, the Maryland Energy Administration, the Maryland PSC's Staff, and the Office of People's Counsel which, among other things, extends BGE's obligation to supply standard offer service for a second transition period. Under the settlement agreement, BGE is obligated to provide market-based standard offer service to residential customers until June 30, 2010, and for commercial and industrial customers for one, two or four year periods beyond June 30, 2004, depending on customer load. The POLR rates charged during this time will recover BGE's wholesale power supply costs and include an administrative fee.

In September 2003, the Maryland PSC approved a second settlement agreement. This phase deals with the bid procurement process that utilities must follow to obtain wholesale power supply to serve retail customers on standard offer service during the second transition period. The settlement contains a model request for proposals, a model wholesale power supply contract, and various requirements pertaining to, among other things, bidder qualifications and bid evaluation criteria. Bidding to supply BGE's standard offer service to commercial and industrial customers beyond June 30, 2004 began in February 2004. The same bidding procedures will be used for supplying BGE's standard offer service to residential customers for the period after June 30, 2006.

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

Electric Load Management

BGE has implemented various programs for use when system-operating conditions or market economics indicate that a reduction in load would be beneficial. We refer to these programs as active load management programs. These programs include:

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

BGE generally activates these programs on summer days when demand and/or wholesale prices are relatively high. The reduction in the summer 2003 peak load from active load management was approximately 342 MW.

Transmission and Distribution Facilities

BGE maintains approximately 250 substations and 1,300 circuit miles of transmission lines throughout central Maryland. BGE also maintains nearly 22,900 circuit miles of distribution lines. The transmission facilities are connected to those of neighboring utility systems as part of the PJM Interconnection. Under the PJM Tariff and various agreements, BGE and other market participants can use regional transmission facilities for energy, capacity and ancillary services transactions including emergency assistance.

We discuss FERC's initiatives in implementing a standard market design for wholesale electric markets in more detail in *Item 7. Management's Discussion and Analysis—FERC Regulation* section.

Electric Operating Statistics

	2003	2002	2001	2000(A)	1999(A)
Revenues *(In millions)*					
Residential	$ 959.0	$ 946.6	$ 885.3	$ 922.6	$ 975.2
Commercial	760.3	809.5	903.0	926.2	939.3
Industrial	155.2	169.6	218.1	203.6	204.3
System Sales	1,874.5	1,925.7	2,006.4	2,052.4	2,118.8
Interchange Sales	—	—	—	53.8	112.1
Other (B)	47.1	40.3	33.6	29.0	29.1
Total	$1,921.6	$1,966.0	$2,040.0	$2,135.2	$2,260.0
Sales *(In thousands)*—MWH					
Residential	12,754	12,652	11,714	11,675	11,349
Commercial	14,919	14,602	14,147	14,042	13,565
Industrial	4,336	4,475	4,445	4,476	4,350
System Sales	32,009	31,729	30,306	30,193	29,264
Customers *(In thousands)*					
Residential	1,061.7	1,052.3	1,040.5	1,033.4	1,021.4
Commercial	112.1	110.8	110.9	108.9	107.7
Industrial	4.9	4.9	5.0	5.0	4.7
Total	1,178.7	1,168.0	1,156.4	1,147.3	1,133.8

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

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

Operating statistics do not reflect the elimination of intercompany transactions.

Gas Business

The wholesale price of natural gas as a commodity is not subject to regulation. All BGE gas customers have the option to purchase gas from alternate suppliers, including subsidiaries of Constellation Energy. BGE continues to deliver gas to all customers within its service territory. This delivery service is regulated by the Maryland PSC.

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

Approximately 50% of the gas delivered on BGE's distribution system is for delivery service only customers. The basis of competition for delivery service customers is primarily commodity price. BGE charges all of its delivery service customers fees to recover the costs for the transportation service it provides. These fees are the same as the delivery charges to customers that purchase gas from BGE.

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

BGE purchases the natural gas it resells to customers directly from many producers and marketers. BGE has transportation and storage agreements that expire from 2005 to 2020.

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

BGE's current maximum storage entitlements are 235,080 DTH per day. To supplement its gas supply at times of heavy winter demands and to be available in temporary emergencies affecting gas supply, BGE has:

- a liquefied natural gas facility for the liquefaction and storage of natural gas with a total storage capacity of 1,092,977 DTH and a daily capacity of 311,500 DTH, and
- a propane air facility with a mined cavern with a total storage capacity equivalent to 564,200 DTH and a daily capacity of 85,000 DTH.

BGE has under contract sufficient volumes of propane for the operation of the propane air facility and is capable of liquefying sufficient volumes of natural gas during the summer months for operations of its liquefied natural gas facility during winter emergencies.

BGE historically has been able to arrange short-term contracts or exchange agreements with other gas companies in the event of short-term disruptions to gas supplies or to meet additional demand.

BGE also participates in the interstate markets by releasing pipeline capacity or bundling pipeline capacity with gas for off-system sales. Off-system gas sales are low-margin direct sales of gas to wholesale suppliers of natural gas outside BGE's service territory. Earnings from these activities are shared between shareholders and customers. BGE makes these sales as part of a program to balance our supply of, and cost of, natural gas.

Gas Operating Statistics

	2003	2002	2001	2000	1999
Revenues *(In millions)*					
Residential					
Excluding Delivery Service	$ 444.5	$ 342.1	$ 378.4	$ 328.4	$ 298.1
Delivery Service	13.6	16.5	16.3	23.5	11.5
Commercial					
Excluding Delivery Service	128.6	89.4	115.5	97.9	79.3
Delivery Service	24.6	29.2	21.4	25.8	24.4
Industrial					
Excluding Delivery Service	11.5	9.3	12.8	10.9	8.2
Delivery Service	11.4	13.9	13.8	16.3	16.1
System Sales	634.2	500.4	558.2	502.8	437.6
Off-system Sales	84.8	74.8	113.6	101.0	42.9
Other	7.0	6.1	8.9	7.8	7.6
Total	$ 726.0	$ 581.3	$ 680.7	$ 611.6	$ 488.1
Sales *(In thousands)*—DTH					
Residential					
Excluding Delivery Service	40,894	35,364	33,147	34,561	34,272
Delivery Service	6,640	6,404	7,201	9,209	4,468
Commercial					
Excluding Delivery Service	13,895	11,583	12,334	13,186	11,733
Delivery Service	29,138	28,429	25,037	22,921	20,288
Industrial					
Excluding Delivery Service	1,143	1,207	1,386	1,386	1,367
Delivery Service	18,399	23,689	23,872	32,382	33,118
System Sales	110,109	106,676	102,977	113,645	105,246
Off-system Sales	12,859	18,551	20,012	22,456	15,543
Total	122,968	125,227	122,989	136,101	120,789
Customers *(In thousands)*					
Residential	575.2	567.3	558.7	553.7	543.5
Commercial	41.1	40.7	40.2	40.1	39.9
Industrial	1.2	1.3	1.4	1.4	1.3
Total	617.5	609.3	600.3	595.2	584.7

Operating statistics do not reflect the elimination of intercompany transactions.

Franchises

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

Other Nonregulated Businesses

Energy Products and Services

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

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

Home Products and Gas Retail Marketing

We offer services to customers including:

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

District Cooling Services

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

Other

Our other nonregulated businesses include investments that we do not consider to be core operations. These include financial investments, real estate projects, and interests in a Latin American distribution project and in a fund that holds interests in two South American energy projects. While our intent is to dispose of these assets, market conditions and other events beyond our control may affect the actual sale of these assets. In addition, a future decline in the fair value of these assets could result in additional losses.

Consolidated Capital Requirements

Our total capital requirements for 2003 were $761 million. Of this amount, $472 million was used in our nonregulated businesses and $289 million was used in our utility operations. We estimate our total capital requirements to be $760 million in 2004.

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

Environmental Matters

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

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

The development (involving site selection, environmental assessments, and permitting), construction, acquisition, and operation of electric generating and distribution facilities are subject to extensive federal, state, and local environmental and land use laws and regulations. From the beginning phases of siting and developing, to the ongoing operation of existing or new electric generating and distribution facilities, our activities involve compliance with diverse laws and regulations that address emissions and impacts to air and water, special, protected and cultural resources (such as wetlands, endangered species, and archeological/historical resources), chemical, and waste handling and noise impacts.

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

Our capital expenditures (excluding allowance for funds used during construction) were approximately $260 million during the five-year period 1999-2003 to comply with existing environmental standards and regulations.

Clean Air Act

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

On October 27, 1998, the Environmental Protection Agency (EPA) issued a rule requiring 22 Eastern states and the District of Columbia to reduce emissions of NOx. The EPA rule requires states to implement controls sufficient to meet their NOx budget by May 30, 2004. However, the Northeast states decided to require compliance in 2003. Coal-fired power plants are a principal target of NOx reductions under this initiative.

Many of our generation facilities are subject to NOx reduction requirements under the EPA rule, including those located in Maryland and Pennsylvania. At the Brandon Shores and Wagner facilities, we installed emission reduction equipment for our coal-fired units to meet Maryland regulations issued pursuant to the EPA's rule. The owners of the Keystone plant in Pennsylvania completed the installation of emissions reduction equipment by July 2003 to meet Pennsylvania regulations issued pursuant to the EPA's rule. Our total cost of the emissions reduction equipment at the Keystone plant was approximately $37 million.

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

We may be impacted by the EPA's designation of certain areas as severe ozone nonattainment areas. These are areas where air pollution levels severely exceed national air quality standards. We own several generating facilities in severe ozone nonattainment areas in Maryland and California. The Clean Air Act requires states to assess fees against every major stationary source of NOx and volatile organic chemicals in severe ozone nonattainment areas if national air quality standards are not achieved by a specified deadline. If implemented, the fee would be assessed based on the magnitude of a source's emissions as compared to its emissions when the area failed to meet the deadline. The exact method of computing these fees has not been established and will depend in part on state implementing regulations that have not been finalized.

The current deadline for most severe nonattainment areas is 2005, including those in which our generating facilities are located. Assessment of fees would commence in 2006 if the current effective date is maintained. However, there is significant uncertainty regarding the date when fees would be assessed in light of pending federal legislation and anticipated EPA rulemaking. Currently, we are unable to estimate the ultimate timing or financial impact of the standard in light of the uncertainty surrounding its effective date and the methodology that will be used in calculating the fees.

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

Based on the level of emissions control that the EPA and states are seeking in these new source review enforcement actions, we believe that material additional costs and penalties could be incurred if the EPA was successful in any future actions regarding our facilities.

On October 27, 2003, the EPA's new source review rule on routine maintenance was published in the Federal Register. The new regulations would establish an equipment replacement cost threshold for determining when major new source review requirements are triggered. Plant owners may spend up to 20% of the replacement value of a generation unit on certain improvements each year without triggering requirements for new pollution controls. Parties had until December 26, 2003, the effective date of the rule, to appeal the agency's decision in court. An appeal was filed with the United States Court of Appeals. The effective date of the rule has been delayed pending review.

The Clean Air Act required the EPA to evaluate the public health impacts of emissions of mercury, a hazardous air pollutant, from coal-fired plants. The EPA decided to control mercury emissions from coal-fired plants. On December 15, 2003, the EPA proposed two alternatives for controlling mercury emissions from generating facilities. The EPA may require the installation of mercury reduction equipment. Alternatively, the EPA may revise standards to allow for the purchase of allowances. Compliance could be required as soon as 2007, or by 2010 depending on

which alternative is selected. We believe final regulations could be issued in 2004 and could affect all oil-fired and coal-fired boilers. The cost of compliance with the final regulations could be material.

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

Clean Water Act

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

In April 2002, the EPA proposed rules under the Clean Water Act that require that cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts. In February 2004, the proposed rules were finalized. The final rules require the installation of additional intake screens or other protective measures, as well as extensive site-specific study and monitoring requirements. We are currently reviewing the final rules and their potential impact to us. Our compliance costs associated with the final rules could be material.

Under current provisions of the Clean Water Act, existing permits must be renewed at least every five years, at which time permit limits come under extensive review and can be modified to account for more stringent regulations. In addition, the permits can be modified at any time. Changes to the water discharge permits of our coal or other fuel suppliers due to federal or state initiatives may increase the cost of fuel, which in turn could have a significant impact on our operations.

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

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

Metal Bank

In the early 1970s, BGE shipped an unknown number of scrapped transformers to Metal Bank of America, a metal reclaimer in Philadelphia. Metal Bank's scrap and storage yard has been found to be contaminated with oil containing high levels of PCBs (hazardous chemicals frequently used as a fire resistant coolant in electrical equipment). On December 7, 1987, the EPA notified BGE and nine other utilities that they are considered potentially responsible parties (PRPs) with respect to the clean-up of the site. BGE, along with the other PRPs, submitted a remedial investigation and feasibility study to the EPA on October 14, 1994, and the EPA issued its Record of Decision (ROD) recommending clean-up for the site on December 31, 1997. On June 26, 1998, the EPA ordered BGE, the other utility PRPs, and the owner/operator to implement the requirements of the ROD. The utility PRPs have submitted the remedial design to EPA. Based on the ROD, BGE's share of the reasonably possible clean-up costs, estimated to be approximately 15.47%, could be as much as $1.3 million higher than amounts we believe are probable and have recorded as a liability in our Consolidated Balance Sheets.

Kane and Lombard Streets

A suit was originally filed by the EPA under CERCLA in October 1989 against BGE and several other defendants in the U.S. District Court for the District of Maryland, seeking to recover past and future clean-up costs at the Kane and Lombard Street site located in Baltimore City, Maryland. The State of Maryland filed a similar complaint in the same case and court in February 1990. The complaints alleged that BGE arranged for coal fly ash to be deposited on the site. The Court dismissed these complaints in November 1995. Maryland began additional investigation on the remainder of the site for the EPA, but never completed the investigation. BGE, along with three other defendants, agreed to complete a remedial investigation and feasibility study of groundwater contamination around the site in a July 1993 consent order. The remedial investigation report and a draft feasibility study were submitted to the EPA in February 2002. In December 2002, the EPA released its proposed remedy for the site and estimated the total clean-up cost for the site to be $6.2 million.

The EPA issued its ROD for the Kane and Lombard Drum site on September 30, 2003. The ROD specifies the clean-up plan for the site, consisting of enhanced reductive dechlorination, a soil management plan, and institutional controls. The ROD was consistent with the proposed remedy the EPA released in December 2002. We expect the EPA to approach the potentially responsible parties regarding implementation of the plan in 2004. The total clean-up costs are

estimated to be $7.3 million. We estimate our current share of site-related costs to be 11.1% of the $7.3 million. Our share of these future costs has not been determined and it may vary from the current estimate. In December 2002, we recorded a liability in our Consolidated Balance Sheets for our share of the clean-up costs that we believe is probable.

68th Street Dump

In July 1999, the EPA notified BGE, along with 19 other entities, that it may be a potentially responsible party at the 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. In April 2003, EPA re-proposed the 68th Street site for listing as a federal Superfund site, but decided not to include the site in its September 2003 update. BGE and other potentially responsible parties are pursuing alternatives to listing as a federal Superfund site, but at this stage, it is not possible to predict the outcome of those discussions, the clean-up cost of the site, or BGE's share of the liability. However, the costs could have a material effect on our, or BGE's, financial results.

Spring Gardens

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

In late December 1996, BGE signed a consent order with the Maryland Department of the Environment that required BGE to implement remedial action plans for contamination at and around the Spring Gardens site. BGE submitted the required remedial action plans, and they have been approved by the Maryland Department of the Environment. Based on these plans, the costs BGE considers to be probable to remedy the contamination are estimated to total $47 million. BGE recorded these costs as a liability in its Consolidated Balance Sheets and deferred these costs, net of accumulated amortization and amounts it recovered from insurance companies, as a regulatory asset. Through December 31, 2003, BGE spent approximately $39 million for remediation at this site.

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

BGE also investigated other small sites where gas was manufactured in the past. We do not expect the clean-up costs of the remaining smaller sites to have a material effect on our, or BGE's, financial results.

Employees

Constellation Energy and its subsidiaries had, at December 31, 2003, approximately 8,650 employees. At the Nine Mile Point plant, approximately 700 employees are represented by the International Brotherhood of Electrical Workers, Local 97. The labor contract with this union expires in June 2006. We believe that our relationship with this union is satisfactory, but there can be no assurances that this will continue to be the case.

Item 2. Properties

Constellation Energy's corporate offices occupy approximately 85,000 square feet of leased office space in Baltimore, Maryland. The corporate offices for most of our merchant energy business occupy approximately 110,000 square feet of leased office space in another building in Baltimore, Maryland. We describe our electric generation properties on the next page. We also have leases for other offices and services located in the Baltimore metropolitan region, and for various real property and facilities relating to our generation projects.

BGE's principal headquarters building is located in downtown Baltimore. In January 2004, BGE sold a portion of its headquarters building and will consolidate its operations into the remainder of the building. In addition, BGE owns propane air and liquefied natural gas facilities as discussed in *Item 1. Business—Gas Business* section.

BGE also has rights-of-way to maintain 26-inch natural gas mains across certain Baltimore City-owned property (principally parks) which expire in 2004. These rights-of-way can be renewed during their last year for an additional period of 25 years based on a fair revaluation. BGE is in the process of renewing these rights-of-way with the City of Baltimore. Conditions of the grants are satisfactory.

BGE has electric transmission and electric and gas distribution lines located:

- in public streets and highways pursuant to franchises, and
- on rights-of-way secured for the most part by grants from owners of the property.

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

We believe we have satisfactory title to our power project facilities in accordance with standards generally accepted in the energy industry, subject to exceptions, which in our opinion, would not have a material adverse effect on the use or value of the facilities.

We also lease office space throughout North America to support our merchant energy business.

The following table describes our generating facilities:

Plant	Location	Installed Capacity (MW)	% Owned	Capacity Owned (MW)	Primary Fuel
		(at December 31, 2003)		(at December 31, 2003)	
Mid-Atlantic Fleet					
Calvert Cliffs	Calvert Co., MD	1,685	100.0	1,685	Nuclear
Brandon Shores	Anne Arundel Co., MD	1,286	100.0	1,286	Coal
H. A. Wagner	Anne Arundel Co., MD	1,020	100.0	1,020	Coal/Oil/Gas
C. P. Crane	Baltimore Co., MD	399	100.0	399	Oil/Coal
Keystone	Armstrong and Indiana Cos., PA	1,711	21.0	359 (A)	Coal
Conemaugh	Indiana Co., PA	1,711	10.6	181 (A)	Coal
Perryman	Harford Co., MD	360	100.0	360	Oil/Gas
Riverside	Baltimore Co., MD	249	100.0	249	Oil/Gas
Handsome Lake	Rockland Twp, PA	250	100.0	250	Gas
Notch Cliff	Baltimore Co., MD	128	100.0	128	Gas
Westport	Baltimore City, MD	121	100.0	121	Gas
Philadelphia Road	Baltimore City, MD	64	100.0	64	Oil
Safe Harbor	Safe Harbor, PA	416	66.7	277	Hydro
Total Mid-Atlantic Fleet		9,400		6,379	
Plants with Power Purchase Agreements					
High Desert	Victorville, CA	830	100.0	830	Gas
Nine Mile Point Unit 1	Scriba, NY	609	100.0	609	Nuclear
Nine Mile Point Unit 2	Scriba, NY	1,148	82.0	941	Nuclear
Oleander	Brevard Co., FL	680	100.0	680	Oil/Gas
University Park	Chicago, IL	300	100.0	300	Gas
Total Plants with Power Purchase Agreements		3,567		3,360	
Competitive Supply					
Rio Nogales	Seguin, TX	800	100.0	800	Gas
Holland Energy	Shelby Co., IL	665	100.0	665	Gas
Big Sandy	Neal, WV	300	100.0	300	Gas
Wolf Hills	Bristol, VA	250	100.0	250	Gas
Total Competitive Supply		2,015		2,015	
Other					
Puna I	Hilo, HI	30	100.0	30	Geothermal
Panther Creek	Nesquehoning, PA	83	50.0	42	Waste Coal
Colver	Colver Township, PA	110	25.0	28	Waste Coal
Sunnyside	Sunnyside, UT	53	50.0	26	Waste Coal
ACE	Trona, CA	102	30.3	31	Coal
Jasmin	Kern Co., CA	33	50.0	17	Coal
POSO	Kern Co., CA	33	50.0	17	Coal
Mammoth Lakes G-1	Mammoth Lakes, CA	8	50.0	4	Geothermal
Mammoth Lakes G-2	Mammoth Lakes, CA	12	50.0	6	Geothermal
Mammoth Lakes G-3	Mammoth Lakes, CA	12	50.0	6	Geothermal
Soda Lake I	Fallon, NV	3	50.0	2	Geothermal
Soda Lake II	Fallon, NV	13	50.0	7	Geothermal
Rocklin	Placer Co., CA	24	50.0	12	Biomass
Fresno	Fresno, CA	24	50.0	12	Biomass
Chinese Station	Sonora, CA	22	45.0	10	Biomass
Malacha	Muck Valley, CA	32	50.0	16	Hydro
SEGS IV	Kramer Junction, CA	30	12.0	4	Solar
SEGS V	Kramer Junction, CA	30	4.0	1	Solar
SEGS VI	Kramer Junction, CA	30	9.0	3	Solar
Total Other		684		274	
Total Generating Facilities		15,666		12,028	

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

The following table describes our processing facilities:

Plant	Location	% Owned	Primary Fuel
A/C Fuels	Hazelton, PA	50.0	Coal Processing
Gary PCI	Gary, IN	24.5	Coal Processing
Low Country	Cross, SC	99.0	Synfuel Processing
PC Synfuel VA I	Appalachia, VA	16.7	Synfuel Processing
PC Synfuel WV I	Charleston, WV	16.7	Synfuel Processing
PC Synfuel WV II	Wheelersburg, OH	16.7	Synfuel Processing
PC Synfuel WV III	Mayberry, WV	16.7	Synfuel Processing

Item 3. Legal Proceedings

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

Item 4. Submission of Matters to Vote of Security Holders

Not applicable.

Executive Officers of the Registrant

Name	Age	Present Office	Other Offices or Positions Held During Past Five Years
Mayo A. Shattuck III	49	Chairman of the Board of Constellation Energy (since July 2002), President and Chief Executive Officer of Constellation Energy (since November 2001); and Chairman of the Board of BGE (since July 2002)	Co-Chairman and Co-Chief Executive Officer—DB Alex Brown, LLC and Deutsche Banc Securities, Inc., Vice Chairman—Bankers Trust Corporation.
E. Follin Smith	44	Executive Vice President (since January 2004) and Chief Financial Officer (since June 2001) and Chief Administrative Officer (since December 2003) of Constellation Energy and Senior Vice President and Chief Financial Officer of Baltimore Gas and Electric Company (since January 2002)	Senior Vice President—Constellation Energy; Senior Vice President and Chief Financial Officer—Armstrong Holdings, Inc.; Vice President and Treasurer—Armstrong Holdings, Inc. (filed for bankruptcy under Chapter 11 on December 6, 2000); and Chief Financial Officer—General Motors—Delphi Chassis Systems.
Thomas V. Brooks	41	President of Constellation Power Source, Inc. (since October 2001); Executive Vice President of Constellation Energy (since January 2004)	Vice President of Business Development and Strategy—Constellation Energy; and Vice President—Goldman Sachs.
Frank O. Heintz	60	President and Chief Executive Officer of Baltimore Gas and Electric Company (since July 2000); Executive Vice President of Constellation Energy (since January 2004)	Executive Vice President, Utility Operations—BGE.
Michael J. Wallace	56	President of Constellation Generation Group, LLC (since January 2002); Executive Vice President of Constellation Energy (since January 2004)	Managing Director and Member—Barrington Energy Partners; and Senior Vice President—Commonwealth Edison.

Name	Age	Present Office	Other Offices or Positions Held During Past Five Years
Thomas F. Brady	54	Executive Vice President, Corporate Strategy and Development of Constellation Energy (since January 2004)	Senior Vice President, Corporate Strategy and Development—Constellation Energy; Vice President, Corporate Strategy and Development—Constellation Energy; Vice President, Corporate Strategy and Development—BGE.
Paul J. Allen	52	Senior Vice President, Corporate Affairs of Constellation Energy (since January 2004)	Vice President, Corporate Affairs—Constellation Energy; Senior Vice President and Group Head—Ogilvy Public Relations.
Kathleen A. Chagnon	44	Senior Vice President (since January 2004), General Counsel and Secretary (since August 2002), and Chief Compliance Officer (since November 2003) of Constellation Energy	Vice President—Constellation Energy; Vice President, Corporate Group General Counsel—The St. Paul Companies, Inc.
John R. Collins	46	Senior Vice President (since January 2004) and Chief Risk Officer of Constellation Energy (since December 2001)	Vice President—Constellation Energy; Managing Director—Finance—Constellation Power Source Holdings, Inc.; and Senior Financial Officer—Constellation Power Source, Inc.
Mark P. Huston	40	Vice President, Corporate Strategy and Development of Constellation Energy (since May 2002)	Manager, Corporate Strategy & Development—Constellation Energy; and Project Manager, Restructuring Project—BGE.
Marc C. Ugol	45	Senior Vice President, Human Resources of Constellation Energy (since January 2004)	Vice President, Human Resources—Constellation Energy; Senior Vice President, Human Resources and Administration—Tellabs, Inc.; and Senior Vice President, Human Resources—Platinum Technology International.

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

PART II

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

Stock Trading

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

As of February 27, 2004, there were 48,287 common shareholders of record.

Dividend Policy

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

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

In January 2004, we announced an increase in our quarterly dividend from $0.26 to $0.285 per share on our common stock payable April 1, 2004 to holders of record on March 10, 2004. This is equivalent to an annual rate of $1.14 per share.

Quarterly dividends were declared on our common stock during 2003 and 2002 in the amounts set forth below.

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

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

Common Stock Dividends and Price Ranges

	2003			2002		
	Dividend Declared	Price* High	Price* Low	Dividend Declared	Price* High	Price* Low
First Quarter	$0.26	$30.23	$25.17	$0.24	$31.18	$26.16
Second Quarter	0.26	34.92	27.50	0.24	32.38	27.65
Third Quarter	0.26	37.65	31.75	0.24	29.85	21.51
Fourth Quarter	0.26	39.61	35.03	0.24	29.02	19.30
Total	$1.04			$0.96		

* Based on New York Stock Exchange Composite Transactions.

Item 6. Selected Financial Data
Constellation Energy Group, Inc. and Subsidiaries

	2003	2002	2001	2000	1999
		(In millions, except per share amounts)			
Summary of Operations					
Total Revenues	$ 9,703.0	$ 4,726.7	$ 3,878.8	$ 3,774.4	$ 3,830.9
Total Expenses	8,662.9	3,901.8	3,527.2	3,009.9	3,081.0
Net Gain on Sales of Investments and Other Assets	26.2	261.3	6.2	78.1	10.0
Income From Operations	1,066.3	1,086.2	357.8	842.6	759.9
Other Income	19.1	30.5	1.3	4.2	7.9
Fixed Charges	340.2	281.5	238.8	271.4	255.0
Income Before Income Taxes	745.2	835.2	120.3	575.4	512.8
Income Taxes	269.5	309.6	37.9	230.1	186.4
Income Before Extraordinary Item and Cumulative Effects of Changes in Accounting Principles	475.7	525.6	82.4	345.3	326.4
Extraordinary Loss, Net of Income Taxes	—	—	—	—	(66.3)
Cumulative Effects of Changes in Accounting Principles, Net of Income Taxes	(198.4)	—	8.5	—	—
Net Income	$ 277.3	$ 525.6	$ 90.9	$ 345.3	$ 260.1
Earnings Per Common Share Assuming Dilution					
Before Extraordinary Item and Cumulative Effects of Changes in Accounting Principles	$ 2.85	$ 3.20	$ 0.52	$ 2.30	$ 2.18
Extraordinary Loss	—	—	—	—	(0.44)
Cumulative Effects of Changes in Accounting Principles	(1.19)	—	0.05	—	—
Earnings Per Common Share Assuming Dilution	$ 1.66	$ 3.20	$ 0.57	$ 2.30	$ 1.74
Dividends Declared Per Common Share	$ 1.04	$ 0.96	$ 0.48	$ 1.68	$ 1.68
Summary of Financial Condition					
Total Assets	$15,800.7	$14,943.3	$14,697.5	$13,248.1	$10,011.4
Short-Term Borrowings	$ 9.6	$ 10.5	$ 975.0	$ 243.6	$ 371.5
Current Portion of Long-Term Debt	$ 343.2	$ 426.2	$ 1,406.7	$ 906.6	$ 808.3
Capitalization					
Long-Term Debt	$ 5,039.2	$ 4,613.9	$ 2,712.5	$ 3,159.3	$ 2,575.4
Minority Interests	113.4	105.3	101.7	97.7	95.2
Preference Stock Not Subject to Mandatory Redemption	190.0	190.0	190.0	190.0	190.0
Common Shareholders' Equity	4,140.5	3,862.3	3,843.6	3,174.0	3,017.5
Total Capitalization	$ 9,483.1	$ 8,771.5	$ 6,847.8	$ 6,621.0	$ 5,878.1
Financial Statistics at Year End					
Ratio of Earnings to Fixed Charges	2.98	3.33	1.18	2.78	2.87
Book Value Per Share of Common Stock	$ 24.68	$ 23.44	$ 23.48	$ 21.09	$ 20.17

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

We discuss items that affect comparability between years, including acquisitions, accounting changes, including the impact of adopting Emerging Issues Task Force Issue (EITF) 02-3, *Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities*, and special items, in *Item 7. Management's Discussion and Analysis.*

	2003	2002	2001	2000(A)	1999
			(In millions)		
Summary of Operations					
Total Revenues	$2,647.6	$2,547.3	$2,720.7	$2,746.8	$3,092.2
Total Expenses	2,262.6	2,181.0	2,408.9	2,334.4	2,387.9
Income From Operations	385.0	366.3	311.8	412.4	704.3
Other (Expense) Income	(5.4)	10.7	0.4	7.5	8.4
Fixed Charges	111.2	140.6	154.6	184.0	205.9
Income Before Income Taxes	268.4	236.4	157.6	235.9	506.8
Income Taxes	105.2	93.3	60.3	92.4	178.4
Income Before Extraordinary Item	163.2	143.1	97.3	143.5	328.4
Extraordinary Loss, Net of Income Taxes	—	—	—	—	(66.3)
Net Income	163.2	143.1	97.3	143.5	262.1
Preference Stock Dividends	13.2	13.2	13.2	13.2	13.5
Earnings Applicable to Common Stock	$ 150.0	$ 129.9	$ 84.1	$ 130.3	$ 248.6
Summary of Financial Condition					
Total Assets	$4,706.6	$4,779.9	$4,954.5	$4,657.4	$7,273.4
Short-Term Borrowings	$ —	$ —	$ —	$ 32.1	$ 129.0
Current Portion of Long-Term Debt	$ 330.6	$ 420.7	$ 666.3	$ 567.6	$ 523.9
Capitalization					
Long-Term Debt	$1,343.7	$1,499.1	$1,821.7	$1,864.4	$2,206.0
Minority Interest	18.9	19.4	5.0	4.6	4.2
Preference Stock Not Subject to Mandatory Redemption	190.0	190.0	190.0	190.0	190.0
Common Shareholder's Equity	1,487.7	1,461.7	1,131.4	802.3	2,355.4
Total Capitalization	$3,040.3	$3,170.2	$3,148.1	$2,861.3	$4,755.6
Financial Statistics at Year End					
Ratio of Earnings to Fixed Charges	3.36	2.66	1.99	2.27	3.45
Ratio of Earnings to Fixed Charges and Preferred and Preference Stock Dividends	2.82	2.31	1.75	2.03	3.14

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

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

Introduction and Overview

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

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

Our merchant energy business is a competitive provider of energy solutions for large customers in North America. It has electric generation assets located in various regions of the United States and provides energy solutions to meet customers' needs. Our merchant energy business focuses on serving the full energy and capacity requirements (load-serving activities) of, and providing other risk management activities for various wholesale customers, such as utilities, municipalities, cooperatives, and retail aggregators, and for retail commercial and industrial customers. These load-serving activities typically occur in regional markets in which end use customer electricity rates have been deregulated and thereby separated from the cost of generation supply.

Our wholesale marketing and risk management operation actively uses energy and energy-related commodities in order to manage our portfolio of energy purchases and sales to customers through structured transactions. As part of our risk management activities we trade power and gas to enable price discovery and facilitate the hedging of our load-serving and other risk management products and services. Within our trading function we allow limited risk-taking activities for profit. These activities are actively managed through daily value at risk and liquidity position limits. We discuss value at risk in more detail later in the *Market Risk* section.

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

Our other nonregulated businesses:

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

In addition, we own several investments that we do not consider to be core operations. These include financial investments, real estate projects, and interests in a Latin American distribution project and in a fund that holds interests in two South American energy projects.

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

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

As you read this discussion and analysis, refer to our Consolidated Statements of Income, which present the results of our operations for 2003, 2002, and 2001. Our 2003 results reflect a significant increase in revenues and operating expenses mainly due to the implementation of Emerging Issues Task Force Issue (EITF) 02-3, *Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities* in January 2003, as well as the full year impact of our 2002 acquisitions, NewEnergy and Alliance. We discuss the cumulative effect of changes in accounting principles in *Note 1* and our acquisitions in *Note 15*. We analyze and explain the differences between periods in the specific line items of our Consolidated Statements of Income.

We have organized our discussion and analysis as follows:

- First, we discuss our strategy.
- We then describe the business environment in which we operate including how regulation, weather, and other factors affect our business.
- Next, we discuss our critical accounting policies. These are the accounting policies that are most important to both the portrayal of our financial condition and results and require management's most difficult, subjective or complex judgment.
- We highlight significant events that occurred in 2003 that are important to understanding our results of operations and financial condition.
- We then review our results of operations beginning with an overview of our total company results, followed by a more detailed review of those results by operating segment.
- We review our financial condition addressing our sources and uses of cash, security ratings, capital resources, capital requirements, and commitments.
- We conclude with a discussion of our exposure to various market risks.

Strategy

We are pursuing a balanced strategy to distribute energy through our North American competitive supply activities and our regulated utility located in Maryland, BGE. Our merchant energy business focuses on long-term, high-value sales of energy, capacity, and related products to large customers, including distribution utilities, municipalities, cooperatives, industrial customers, and commercial customers primarily in the regional markets in which end-use customer electricity rates have been deregulated and thereby separated from the cost of generation supply. These markets include:

- the New England, New York, and Mid-Atlantic regions,
- Texas,
- the Mid-West region,
- the West region, and
- certain areas in Canada.

We obtain this energy through both owned and contracted generation. Our generation fleet is strategically located in deregulated markets across the country and is diversified by fuel type, including nuclear, coal, gas, oil, and renewable sources. Where we do not own generation, we contract for power from other merchant providers, typically through power purchase agreements. We intend to remain diversified between regulated transmission and distribution and competitive supply. We will use both our owned generation and our contracted generation to support our competitive supply operation.

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

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

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

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

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

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

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

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

We are constantly reevaluating our strategies and might consider:

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

Business Environment

General Industry

Over the past several years, the utility industry and energy markets experienced significant changes as a result of less liquid and more volatile wholesale markets, credit quality deterioration of various industry participants, and the slowing of the U.S. economy.

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

During 2003, the energy markets continued to be highly volatile with significant changes in natural gas and power prices, as well as the continuation of reduced liquidity in the marketplace. We continue to actively manage our credit portfolio to attempt to reduce the impact of a potential counterparty default. We discuss our counterparty credit and other risks in more detail in the *Market Risk* section.

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

Electric Competition

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

Maryland

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

- All customers can choose their electric energy supplier. BGE provides fixed price standard offer service over various time periods for different classes of customers that do not select an alternative supplier until June 30, 2006.
- While BGE does not sell electric commodity to all customers in its service territory, BGE does deliver electricity to all customers and provides meter reading, billing, emergency response, regular maintenance, and balancing services.

- BGE provides a market rate standard offer service for those commercial and industrial customers who are no longer eligible for fixed price standard offer service.
- BGE residential base rates will not change before July 2006. While total residential base rates remain unchanged over the initial transition period (July 1, 2000 through June 30, 2006), annual standard offer service rate increases are offset by corresponding decreases in the competitive transition charge (CTC) that BGE receives from its customers.
- Commercial and industrial customers have several service options that will fix electric energy rates through June 30, 2004 and the CTC through June 30, 2006.
- BGE transferred, at book value, its generating assets and related liabilities to the merchant energy business.

Standard Offer Service

Our wholesale marketing and risk management operation is providing BGE with 100% of the energy and capacity required to meet its commercial and industrial standard offer service obligations through June 30, 2004 and 100% of the energy and capacity required to meet its residential standard offer service obligations through June 30, 2006. BGE will obtain its supply for standard offer service to its commercial and industrial customers beginning July 1, 2004, and to its residential customers beginning July 1, 2006, through a competitive wholesale bidding process as discussed in the *Standard Offer Service—Provider of Last Resort (POLR)* section below. Our wholesale marketing and risk management operation obtains the energy and capacity to supply BGE's standard offer service obligations from our merchant energy operating plants in the PJM Interconnection (PJM) region, supplemented with energy and capacity purchased from the wholesale market, as necessary.

Beginning July 1, 2002, the fixed price standard offer service rate ended for certain of our large commercial and industrial customers. As a result, the majority of these customers purchase their electricity from alternate suppliers, including subsidiaries of Constellation Energy. The remaining large commercial and industrial customers that continue to receive their electric supply from BGE are charged market-based standard offer service rates through June 30, 2004.

Beginning July 1, 2004, all other commercial and industrial customers that receive their electric supply from BGE will be charged market-based standard offer service rates. Beginning July 1, 2006, BGE's current obligation to provide fixed price standard offer service to residential customers ends and all residential customers that receive their electric supply from BGE will be charged market-based standard offer service rates.

Standard Offer Service—Provider of Last Resort (POLR)

In April 2003, the Maryland Public Service Commission (Maryland PSC) approved a settlement agreement reached by BGE and parties representing customers, industry, utilities, suppliers, the Maryland Energy Administration, the Maryland PSC's Staff, and the Office of People's Counsel which, among other things, extends BGE's obligation to supply standard offer service for a second transition period. Under the settlement agreement, BGE is obligated to provide market-based standard offer service for a second transition period to residential customers until June 30, 2010, and for commercial and industrial customers for a one, two or four year period beyond June 30, 2004, depending on customer load. The POLR rates charged during this time will recover BGE's wholesale power supply costs and include an administrative fee.

In September 2003, the Maryland PSC approved a second settlement agreement. This phase deals with the bid procurement process that utilities must follow to obtain wholesale power supply to serve retail customers on standard offer service during the second transition period. The settlement contains a model request for proposals, a model wholesale power supply contract, and various requirements pertaining to, among other things, bidder qualifications and bid evaluation criteria. Bidding to supply BGE's standard offer service to commercial and industrial customers beyond June 30, 2004, began in February 2004. The same bidding procedures will be used for supplying BGE's standard offer service to residential customers for the period after June 30, 2006.

Other States

Several states, other than Maryland, have supported deregulation of the electric industry. The pace of deregulation in other states varies based on historical moves to competition and responses to recent market events. Certain states that were considering deregulation have slowed their plans or postponed consideration. In addition, other states are reconsidering deregulation. Our merchant energy business is also affected by regional regulatory or legislative decisions, which may impact our financial results and our ability to successfully execute our growth strategy.

In response to regional market differences and to promote competitive markets, the FERC proposed initiatives promoting the formation of Regional Transmission Organizations and a standard market design. If approved, these market changes could provide additional opportunities for our merchant energy business. We discuss these initiatives in the *FERC Regulation—Regional Transmission Organizations and Standard Market Design* section.

Gas Competition

The wholesale price of natural gas is not subject to regulation. All BGE gas customers have the option to purchase gas from alternate suppliers.

Regulation by the Maryland PSC

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

Base Rate

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

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

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

Gas Fuel Rate

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

FERC Regulation

Regional Transmission Organizations and Standard Market Design

In 1997, BGE turned over the operation of its transmission facilities to PJM, a power pool in the Mid-Atlantic region. In December 1999, FERC issued Order 2000, amending its regulations under the Federal Power Act to advance the formation of Regional Transmission Organizations (RTOs) that would allow easier access to transmission. PJM received FERC approval of its RTO status in December 2002 pending certain compliance filings.

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

In April 2003, the FERC issued a report that indicated its position with respect to the proposed rulemaking and announced that it intends to leave relatively unmodified existing RTO practices, to allow flexibility among regional approaches, to allow phased-in implementation of the final rule, and to provide an increased deference to states' concerns. Concurrently, proposed federal legislation has been introduced that would remand the rulemaking process to FERC, require the issuance of a new notice of proposed rulemaking, and delay the issuance of a final rule until at least January 1, 2007.

We believe that, while the original SMD proposal would have led to uniform rules that would have been largely favorable to Constellation Energy and BGE, the revised regional approach should result in improved market operations across various regions. The proposed federal legislation does not appear to exclude a regional approach to market development. Overall, the trend continues to be toward increased competition in the regions. The region where BGE operates is expected to be relatively unaffected by this proceeding, based on current compliance by the PJM with the SMD proposal.

Weather

Merchant Energy Business

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

BGE

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

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

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

We show the number of cooling and heating degree-days in 2003 and 2002, 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:

	2003	2002	30-year Average
Cooling degree-days	755	1,006	839
Percentage change from prior year	(25.0)%		
Heating degree-days	5,140	4,542	4,729
Percentage change from prior year	13.2%		

Other Factors

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

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

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

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

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

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

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

Environmental and Legal Matters

You will find details of our environmental matters in *Note 12* and *Item 1. Business—Environmental Matters* section. You will find details of our legal matters in *Note 12*. Some of the information is about costs that may be material to our financial results.

Accounting Standards Adopted and Issued

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

Critical Accounting Policies

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

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

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

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

Management believes the following accounting policies represent critical accounting policies as defined by the SEC. We discuss our significant accounting policies, including those that do not require management to make difficult, subjective, or complex judgments or estimates, in *Note 1*.

Revenue Recognition/Mark-to-Market Method of Accounting

Our merchant energy business enters into contracts for energy, other energy-related commodities, and related derivatives. We record merchant energy business revenues using two methods of accounting: accrual accounting and mark-to-market accounting. We describe our use of accrual accounting (including hedge accounting) in more detail in *Note 1*.

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

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

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

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

- Close-out reserve—this reserve represents the estimated cost to close out or sell to a third-party open mark-to-market positions. This reserve has the effect of valuing "long" positions at the bid price and "short" positions at the offer price. We compute this reserve using a market-based estimate of the bid/offer spread for each commodity and option price and the absolute quantity of our net open positions for each year. To the extent that we are not able to obtain market information for similar contracts, the close-out reserve is equivalent to the initial contract margin, thereby resulting in no gain or loss at inception. The level of total close-out reserves increases as we have larger unhedged positions, bid-offer spreads increase, or market information is not available, and it decreases as we reduce our unhedged positions, bid-offer spreads decrease, or market information becomes available.

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

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

In October 2002, the EITF reached a consensus on Issue 02-3. This consensus prohibits mark-to-market accounting for energy-related contracts that do not meet the definition of a derivative under Statement of Financial Accounting Standards (SFAS) No. 133, *Accounting for Derivative Instruments and Hedging Activities, as amended.* As a result, we began to account for all non-derivative contracts on the accrual basis of accounting effective January 1, 2003 as described in *Note 1*. The consensus also prohibits recording unrealized gains or losses at the inception of derivative contracts unless the fair value of each contract in its entirety is evidenced by quoted market prices or other current market transactions for contracts with similar terms and counterparties, and it requires gains and losses on derivative energy trading contracts (whether realized or unrealized) to be reported as revenue on a net basis in the income statement.

EITF 02-3 affects the timing of recognizing earnings on non-derivative transactions. In general, beginning in 2003 earnings on non-derivative transactions subject to EITF 02-3 are no longer recognized at the inception of the transactions as they were under mark-to-market accounting because they are subject to accrual accounting and are recognized over the term of the transaction. As a result, while total earnings over the term of a transaction are the same as they would have been under mark-to-market accounting, our reported earnings for contracts subject to EITF 02-3 generally match the cash flows from those contracts more closely. Additionally, because we record revenues and costs on a gross basis under accrual accounting, our revenues and costs increased, but our earnings have not been affected by gross versus net reporting.

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

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

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

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

Long-Lived Assets

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

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

For long-lived assets that are expected to be held and used, SFAS No. 144 provides that an impairment loss shall only be recognized if the carrying amount of an asset is not recoverable and exceeds its fair value. The carrying amount of an asset is not recoverable under SFAS No. 144 if the carrying amount

exceeds the sum of the undiscounted future cash flows expected to result from the use and eventual disposition of the asset. Therefore, when we believe an impairment condition may have occurred, we are required to estimate the undiscounted future cash flows associated with a long-lived asset or group of long-lived assets. This necessarily involves judgment surrounding the inherent uncertainty of future cash flows.

In order to estimate an asset's future cash flows, we consider historical cash flows, as well as reflect our understanding of the extent to which future cash flows will be either similar to or different from past experience based on all available evidence. To the extent applicable, the assumptions we use are consistent with forecasts that we are otherwise required to make (for example, in preparing our other earnings forecasts). If we are considering alternative courses of action to recover the carrying amount of a long-lived asset (such as the potential sale of an asset), we probability-weight the alternative courses of action to estimate the cash flows.

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

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

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

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

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

Goodwill

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

Asset Retirement Obligations

We incur legal obligations associated with the retirement of certain long-lived assets. SFAS No. 143, *Accounting for Asset Retirement Obligations*, provides the accounting for legal obligations associated with the retirement of long-lived assets. We incur such legal obligations as a result of environmental and other government regulations, contractual agreements, and other factors. The application of this standard requires significant judgment due to the large number and diverse nature of the assets in our various businesses and the estimation of future cash flows required to measure legal obligations associated with the retirement of specific assets.

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

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

Significant Events of 2003

In 2003, we recorded the following special items in earnings:

	Pre-Tax	After-Tax
	(In millions)	
Workforce reduction costs	$ (2.1)	$(1.3)
Impairment losses and other costs	(0.6)	(0.4)
Net gain on sales of investments and other assets	26.2	16.4
Total special items	$ 23.5	$14.7

Workforce Reduction Costs

During 2003, we recorded costs of $2.1 million pre-tax, or $1.3 million after-tax, of which BGE recorded $0.7 million pre-tax, associated with deferred payments to employees eligible for the 2001 Voluntary Special Early Retirement Program.

Impairment Losses and Other Costs

In 2003, our other nonregulated businesses recognized an impairment loss of $0.6 million pre-tax, or $0.4 million after-tax, related to the decline in value of our investment in an airplane that we sold in January 2004.

In the fourth quarter of 2003, we began re-evaluating our strategy regarding ourgeothermal generating facility in Hawaii. This facility has property, plant and equipment with a net book value of approximately $137 million. If we ultimately dispose of the geothermal facility, the actual proceeds received could be less than the carrying value of the plant, resulting in a loss that could be material. We discuss this in further detail in the *Merchant Energy Business—Other* section on page 42.

Net Gain on Sales of Investments and Other Assets

During 2003, our other nonregulated businesses recognized $26.2 million of pre-tax, or $16.4 million after-tax, gains on the sales of non-core assets as follows:

- a $13.1 million pre-tax gain on the sale of several parcels of real estate,
- a $7.2 million pre-tax gain on the sale of an oil tanker to the U.S. Navy,
- a $5.3 million pre-tax gain on the favorable settlement of a contingent obligation we had previously reserved relating to the sale of our Guatemalan power plant operation in the fourth quarter of 2001, and
- a $0.6 million pre-tax gain on the sale of financial investments.

We discuss our 2002 and 2001 special items in more detail in *Note 2*.

Hurricane Isabel

In September 2003, Hurricane Isabel caused damage to the electric and gas distribution systems of BGE. As a result, during 2003, BGE incurred capitalized costs of $32.0 million and maintenance expenses of $36.8 million pre-tax, or $22.2 million after-tax to restore its distribution system. The maintenance expenses included $32.1 million pre-tax, or $19.4 million after-tax, of incremental expenses.

Generating Facility Commenced Operations

In April 2003, our High Desert Power Project in Victorville, California, an 830 megawatt (MW) gas-fired combined cycle facility, commenced operations. The project has a long-term power sales agreement with the California Department of Water Resources (CDWR). The contract is a "tolling" structure, under which the CDWR pays a fixed amount of $12.1 million per month and provides CDWR the right, but not the obligation, to purchase power from the project at a price linked to the variable cost of production. During the term of the contract, which runs for seven years and nine months from the April 2003 commercial operation date of the plant, the project will provide energy exclusively to the CDWR.

Prior to June 2003, we accounted for this project as an operating lease. In June 2003, we exercised our option to pay off the lease, acquired the assets from the lessor, and included the assets and liabilities in our Consolidated Balance Sheets. We describe the net assets acquired in *Note 15*. We include the results of the High Desert Power Project in our merchant energy business segment.

Acquisitions

During 2003, our merchant energy business acquired the following energy contract portfolios:

- customer load-serving contracts representing 940 MW and corresponding supply portfolio from a subsidiary of CMS Energy Corp, and
- the load-serving contract and related hedges from Allegheny Energy Supply Company, LLC to provide 10% of the standard offer service to BGE for the period from July 1, 2003 through June 30, 2006.

On October 22, 2003, we purchased Blackhawk Energy Services (Blackhawk) and Kaztex Energy Management (Kaztex). Blackhawk and Kaztex are providers of natural gas and electricity products throughout Illinois and Wisconsin, serving approximately 1,100 customers representing approximately 70 billion cubic feet of natural gas and 0.9 million megawatt hours of electricity. We acquired 100% ownership of both companies for $26.9 million. We acquired cash of $1.2 million as part of the purchase. We describe the net assets acquired in *Note 15*. We include the results of Blackhawk and Kaztex in our merchant energy business segment beginning on the date of acquisition.

In addition, as part of our growth strategy, our merchant energy business had other acquisitions including a synthetic fuel facility in South Carolina, various competitive energy supply contract portfolios with commercial and industrial customers, certain gas contracts and a wholesale marketing business in Canada.

Planned Acquisition

On November 25, 2003, we announced an agreement with Rochester Gas and Electric (RG&E) to acquire the R.E. Ginna Nuclear Power Plant (Ginna) located north of Rochester, New York. Upon closing the acquisition of this 495 MW facility, we will own and operate three nuclear power stations. The estimated purchase price for the Ginna plant is $401 million, excluding approximately $22 million for purchased nuclear fuel. RG&E will transfer approximately $202 million in decommissioning funds at the time of closing. We believe this transfer will be sufficient to meet the decommissioning requirements of the facility.

The transaction is contingent upon regulatory approvals, including license extension. The acquisition includes a long-term unit contingent power purchase agreement where we will sell 90% of the plant's output and capacity to RG&E for 10 years at an average price of $44.00 per MWH. The remaining 10% of the plant's output will be managed by our wholesale marketing and risk management operation and will be sold into the wholesale market.

Synthetic Fuel Tax Credits

We have investments in facilities that manufacture solid synthetic fuel produced from coal as defined under Section 29 of the Internal Revenue Code for which we claim tax credits on our Federal income tax return. We recognize the tax benefit of these credits in our Consolidated Statements of Income when we believe it is highly probable that the credits will be sustained. The synthetic fuel process involves combining coal material with a chemical reagent to create a significant chemical change. A taxpayer may request a private letter ruling from the Internal Revenue Service (IRS) to support its position that the synthetic fuel produced undergoes a significant chemical change and thus qualifies for Section 29 credits.

As of December 31, 2003, we have recognized cumulative tax benefits associated with Section 29 credits of $78.0 million, of which $35.0 million was recognized during the year ended December 31, 2003. These credits relate to our minority ownership interest in four synthetic fuel facilities located in Ohio, Virginia and West Virginia. These facilities have received private letter rulings from the IRS. In January 2004, the IRS concluded its examination of the partnership that owns these facilities for the tax years 1998 through 2001 and the IRS did not disallow any of the previously recognized synthetic fuel credits. We are awaiting final written notice of the resolution of the examination from the IRS.

In 2003, we purchased 99% ownership in a South Carolina facility that produces synthetic fuel. On January 12, 2004, we submitted our request for a private letter ruling to the IRS for our South Carolina facility. Our South Carolina facility is using the same synthetic fuel process that was utilized by the previous owner, which had received a private letter ruling. To date, we have not yet received our private letter ruling from the IRS for our South Carolina facility.

Since we may not rely upon a private letter ruling issued by the IRS to another taxpayer, we have not recognized the tax benefit of approximately $36 million for these credits in our Consolidated Statements of Income during 2003. We have the option under the amended purchase agreement for this facility to terminate our participation, without penalty, by April 5, 2004. We are currently evaluating our strategy regarding this facility and have not decided whether we will end our participation.

While we believe the production and sale of synthetic fuel from all of our synthetic fuel facilities meet the conditions to qualify for tax credits under Section 29 of the IRS Code, we cannot predict the timing or outcome of any future challenge by the IRS, legislative or regulatory action, or the ultimate impact of such events on the Section 29 credits that we have claimed to date or expect to claim in the future, but the impact could be material to our financial results.

Calvert Cliffs Extended Outage

In April 2003, our merchant energy business completed the Unit 2 steam generator replacement and refueling outage at Calvert Cliffs. This outage was completed in 66 days, 58 fewer days than a similar outage completed at Calvert Cliff's Unit 1 in June 2002.

Dividend Increase

In January 2004, we announced an increase in our quarterly dividend from 26 cents to 28.5 cents per share on our common stock payable April 1, 2004 to holders of record on March 10, 2004. This is equivalent to an annual rate of $1.14 per share.

Results of Operations

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

Overview

Results

	2003	2002	2001
	(In millions, after-tax)		
Merchant energy	$ 313.0	$247.2	$ 93.1
Regulated electric	107.5	99.3	50.9
Regulated gas	43.0	31.1	37.5
Other nonregulated	12.2	148.0	(99.1)
Net Income Before Cumulative Effects of Changes in Accounting Principles	475.7	525.6	82.4
Cumulative Effects of Changes in Accounting Principles	(198.4)	—	8.5
Net Income	$ 277.3	$525.6	$ 90.9
Special Items Included in Operations:			
Net gain on sales of investments and other assets	$ 16.4	$166.7	$ 1.9
Workforce reduction costs	(1.3)	(38.0)	(64.1)
Impairments of real estate, senior-living, and other investments	(0.4)	(1.2)	(72.5)
Impairments of investment in qualifying facilities and domestic power projects	—	(9.9)	(30.5)
Costs associated with exit of BGE Home merchandise stores	—	(6.1)	—
Contract termination related costs	—	—	(139.6)
Total Special Items	$ 14.7	$111.5	$(304.8)

2003

Our total net income for 2003 decreased $248.3 million, or $1.54 per share, compared to 2002 mostly because of the following:

- We recorded a $266.1 million after-tax, or $1.60 per share, charge for the cumulative effect of adopting EITF 02-3. This was partially offset by a $67.7 million after-tax, or $0.41 per share, gain for the cumulative effect of adopting SFAS No. 143. We discuss these cumulative effect items in more detail in *Note 1*.
- We recognized a $163.3 million after-tax, or $1.00 per share, gain on the sale of our investment in Orion in 2002 that had a positive impact in that period. We discuss the sale of Orion in more detail in *Note 2*.
- We had higher expenses in our wholesale competitive supply activities relating to the expansion of our wholesale operations, higher operating costs at our generation facilities, and other inflationary pressures.
- We had higher fixed charges due to lower capitalized interest and a higher level of debt outstanding as a result of refinancing our High Desert Power Project.
- Our results reflect the impact of the shift to accrual accounting under EITF 02-3. Specifically, the absence of 2002 mark-to-market gains for contracts accounted for on an accrual basis in 2003 and the timing difference in the recognition of earnings for certain economic hedges, which we discuss further in the *Competitive Supply—Mark-to-Market Revenues* section, were only partially offset by the 2003 recognition of accrual earnings on transactions entered into in prior periods.
- Our regulated electric business incurred distribution service restoration expenses associated with Hurricane Isabel.

These decreases were partially offset by the following:

- We had higher earnings from wholesale competitive supply activities resulting from effective portfolio management, partially offset by lower mark-to-market origination in 2003.
- We had higher earnings from favorable generating plant operational performance. Specifically, our High Desert Power Project commenced operations in April 2003 and Calvert Cliffs completed a steam generator replacement in April 2003, 58 fewer days than a similar outage that was completed in June 2002.
- We had higher workforce reduction costs in 2002 that had a negative impact in the period.
- We realized cost reductions due to productivity initiatives.
- We had higher earnings from the acquisition of Alliance and from a full year of NewEnergy.
- We had higher earnings from our regulated business, excluding the impacts of Hurricane Isabel.
- Our other nonregulated business recognized a gain of $16.4 million after-tax, or $0.10 per share, in 2003 related to non-core asset sales.
- We had higher earnings from our other nonregulated businesses primarily related to improved operations of our international portfolio.
- We recognized impairments of certain investments in qualifying facilities, real estate, and other investments in 2002 that had a negative impact in that period.
- We had costs associated with our exit of BGE Home merchandise stores in 2002 that had a negative impact in that period.

2002

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

- We recognized a $163.3 million after-tax gain, or $1.00 per share, on the sale of our investment in Orion.
- We recorded special items in 2001 that had a negative impact in that year.
- We had cost reductions due to productivity initiatives associated with our corporate-wide workforce reduction and other productivity programs.
- The addition of Nine Mile Point Nuclear Station (Nine Mile Point) to the generation fleet increased net income.

- We benefited from the absence of Goldman Sachs fees due to the termination of the power business services agreement in October 2001. We discuss the Goldman Sachs termination in more detail in *Note 2.*
- We had higher mark-to-market earnings from our wholesale marketing and risk management operation.
- We had higher earnings from our regulated electric business because of warmer summer weather in the central Maryland region.
- We had higher earnings from the addition of NewEnergy.
- We had higher earnings from our other nonregulated businesses due to the growth of our energy services business and improved results from our international portfolio.

These increases were partially offset by special items recorded in 2002 and the following:

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

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

- an $8.5 million after-tax, or $0.05 per share, gain for the cumulative effect of adopting SFAS No. 133, and
- gains on the sale of securities of $30.0 million after-tax, or $0.19 per share.

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

Merchant Energy Business

Background

Our merchant energy business is a competitive provider of energy solutions for large customers in North America. We discuss the impact of deregulation on our merchant energy business in the *Business Environment—Electric Competition* section.

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

- We record revenues as they are earned and fuel and purchased energy costs as they are incurred for contracts and activities subject to accrual accounting, including certain load-serving activities.
- Prior to the settlement of the forecasted transaction being hedged, we record changes in the fair value of contracts designated as cash-flow hedges in other comprehensive income to the extent that the hedges are effective. We record the effective portion of the changes in fair value of hedges in earnings in the period the settlement of the hedged transaction occurs. We record the ineffective portion of the changes in fair value of hedges, if any, in earnings in the period in which the change occurs.
- We record changes in the fair value of contracts that are subject to mark-to-market accounting in revenues on a net basis in the period in which the change occurs.

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

In the first quarter of 2003, we adopted EITF 02-3, which requires non-derivative contracts to be accounted for on the accrual basis and recorded in our Consolidated Statements of Income gross rather than net. The primary contracts affected were our full requirements load-serving contracts and unit-contingent power purchase contracts. The majority of these contracts were in Texas and New England and were entered into prior to our shift to accrual accounting earlier in 2002. We discuss our shift to accrual accounting during 2002 in more detail in the *Competitive Supply—Accrual Revenues and Fuel and Purchased Energy Expenses* section. We discuss the adoption of EITF 02-3 in more detail in *Note 1.*

After the re-designation of existing contracts to non-trading, we record revenues and expenses on a gross basis, but this does not have a material impact on earnings because the resulting increase in revenues is accompanied by a similar increase in fuel and purchased energy expenses.

EITF 02-3 affects the timing of recognizing earnings on non-derivative transactions. Earnings on new non-derivative transactions subject to EITF 02-3 are no longer recognized at the inception of the transactions as they were under mark-to-market accounting because they are subject to accrual accounting and are recognized over the term of the transaction.

Additionally, we expect lower earnings volatility for this portion of our business because unrealized changes in the fair value of non-derivative load-serving contracts will no longer be recorded as revenue at the time of the change as they were under mark-to-market accounting.

Results

	2003	2002	2001
		(In millions)	
Revenues	$ 7,648.1	$ 2,789.4	$1,765.5
Fuel and purchased energy expenses	(5,672.5)	(1,175.0)	(484.5)
Operations and maintenance expenses	(970.9)	(787.4)	(597.8)
Workforce reduction costs	(1.2)	(26.5)	(46.0)
Impairment losses and other costs	—	(14.4)	(46.9)
Contract termination related costs	—	—	(224.8)
Depreciation and amortization	(229.5)	(242.8)	(174.9)
Accretion of asset retirement obligations	(42.7)	—	—
Taxes other than income taxes	(103.0)	(83.5)	(49.4)
Net loss on sales of assets	—	(3.7)	—
Income from Operations	$ 628.3	$ 456.1	$ 141.2
Income before cumulative effects of changes in accounting principles (after-tax)	$ 313.0	$ 247.2	$ 93.1
Cumulative effects of changes in accounting principles (after-tax)	(198.4)	—	—
Net Income	$ 114.6	$ 247.2	$ 93.1
Special Items Included in Operations (after-tax)			
Workforce reduction costs	$ (0.7)	$ (16.0)	$ (28.0)
Impairment of investments in qualifying facilities and domestic power projects	—	(9.9)	(30.5)
Net loss on sales of assets	—	(2.4)	—
Contract termination related costs	—	—	(139.6)
Total Special Items	$ (0.7)	$ (28.3)	$ (198.1)

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

Revenues and Fuel and Purchased Energy Expenses

Our merchant energy business manages the revenues we realize from the sale of energy to our customers and our costs of procuring fuel and energy. The difference between revenues and fuel and purchased energy expenses is the primary driver of the profitability of our merchant energy business. Accordingly, we believe it is appropriate to discuss the operating results of our merchant energy business by analyzing the changes in the relationship between revenues and fuel and purchased energy expenses. In managing our portfolio, we occasionally terminate, restructure, or acquire contracts. Such transactions are within the normal course of managing our portfolio and may materially impact the timing of our recognition of revenues and fuel and purchased energy expenses. We discuss non-fuel direct costs, such as ancillary services, transmission costs, brokerage fees, and legal costs in conjunction with other operations and maintenance expenses later in the *Operations and Maintenance Expenses* section.

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

- Mid-Atlantic Fleet—our fossil, nuclear, and hydroelectric generating facilities and load-serving activities in the PJM Interconnection (PJM) region for which the output is primarily used to serve BGE. This also includes active portfolio management of the generating assets and associated physical and financial arrangements.
- Plants with Power Purchase Agreements—our generating facilities with long-term power purchase agreements, including our Nine Mile Point Nuclear Station (Nine Mile Point), Oleander, University Park, and High Desert facilities.
- Competitive Supply—our wholesale marketing and risk management operation that provides energy products and services to distribution utilities and other wholesale customers. We also provide electric and gas energy services to retail commercial and industrial customers. We began to manage our gas-fired facilities in the Mid-West region, which were previously part of our "Other" category, as part of our competitive supply activities beginning in the second quarter of 2003. This occurred in connection with the acquisition of the load-serving customers from CMS Energy Corp., as previously discussed in the *Significant Events of 2003* section.
- Other—our investments in qualifying facilities and domestic power projects and our generation and consulting services.

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

	2003	2002	2001
		(Dollar amounts in millions)	
Revenues:			
Mid-Atlantic Fleet	$ 1,774.5	$ 1,415.1	$1,379.2
Plants with Power Purchase Agreements	620.0	456.4	70.8
Competitive Supply	5,208.5	861.5	235.0
Other	45.1	56.4	80.5
Total	$ 7,648.1	$ 2,789.4	$1,765.5
Fuel and purchased energy expenses:			
Mid-Atlantic Fleet	$ (789.9)	$ (551.2)	$ (420.9)
Plants with Power Purchase Agreements	(51.9)	(40.0)	(13.9)
Competitive Supply	(4,830.7)	(583.8)	(49.7)
Other	—	—	—
Total	$(5,672.5)	$(1,175.0)	$ (484.5)

Revenues less fuel and purchased energy expenses:		% of Total		% of Total		% of Total
Mid-Atlantic Fleet	$ 984.6	50%	$ 863.9	53%	$ 958.3	75%
Plants with Power Purchase Agreements	568.1	29	416.4	26	56.9	4
Competitive Supply	377.8	19	277.7	17	185.3	14
Other	45.1	2	56.4	4	80.5	7
Total	$ 1,975.6	100%	$ 1,614.4	100%	$1,281.0	100%

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

Mid-Atlantic Fleet

	2003	2002	2001
		(In millions)	
Revenues	$1,774.5	$1,415.1	$1,379.2
Fuel and purchased energy expenses	(789.9)	(551.2)	(420.9)
Revenues less fuel and purchased energy expenses	$ 984.6	$ 863.9	$ 958.3

Revenues

We provide the changes in Mid-Atlantic Fleet revenues compared to the respective prior years in the following table:

	2003 vs. 2002	2002 vs. 2001
	(In millions)	
BGE's standard offer service	$ (61.2)	$ (8.3)
BGE Home electric sales	29.7	45.3
Other	390.9	(1.1)
Total increase	$359.4	$ 35.9

The decreases for both periods in BGE's standard offer service revenues were mostly due to approximately 1,200 MW of large commercial and industrial customers leaving BGE's standard offer service in the second quarter of 2002 and electing other electric generation suppliers. In 2002 compared to 2001, the decrease was partially offset by higher volumes sold due to warmer summer weather.

Approximately one-third of the load for large commercial and industrial customers that left BGE's standard offer service elected BGE Home, a subsidiary of Constellation Energy, as their electric generation supplier. Our merchant energy business continues to provide the energy to BGE Home to meet the requirements of these customers under market-based rates. Beginning in the second quarter of 2003, as contracts for large commercial and industrial customers being served by BGE Home expire, the renewal of any customer will be with NewEnergy, our subsidiary which provides electric and gas energy services to commercial and industrial customers and which is included in our Competitive Supply category.

Other Mid-Atlantic Fleet revenues increased $390.9 million during 2003 compared to 2002. The increase is primarily due to the following:

- higher sales of energy and related services from our owned generation in excess of that used to serve BGE's standard offer service, including our active portfolio management of these generating assets and associated physical and financial arrangements,
- a gain on the assumption of the Allegheny load-serving contract for the remaining 10% of the BGE standard offer service load, and
- increased sales to BGE Home related to their gas programs.

Other Mid-Atlantic Fleet revenues were about the same in 2002 compared to 2001.

Fuel and Purchased Energy Expenses

Our merchant energy business had higher fuel and purchased energy expenses for the Mid-Atlantic Fleet in 2003 compared to 2002 primarily due to the following:

- higher generation costs related to the increased sales of energy and related services from our owned generation in excess of that used to serve BGE's standard offer service, and
- increased costs related to increased sales to BGE Home related to their gas programs.

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

Plants with Power Purchase Agreements

	2003	2002	2001
		(In millions)	
Revenues	$620.0	$456.4	$ 70.8
Fuel and purchased energy expenses	(51.9)	(40.0)	(13.9)
Revenues less fuel and purchased energy expenses	$568.1	$416.4	$ 56.9

The increases in revenues during 2003 compared to 2002 were primarily due to:

- revenues of $111.3 million from High Desert that commenced operations in the second quarter of 2003,
- higher revenues of $22.2 million from the Oleander generating facility which commenced operations late in the second quarter of 2002, and
- higher revenues of $19.9 million from Nine Mile Point because there were fewer forced outage days in 2003 as compared to 2002.

Our plants with purchase power agreements had higher fuel and purchased energy expenses in 2003 due to the operation of High Desert and the Oleander facilities.

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

Competitive Supply

	2003	2002	2001
		(In millions)	
Accrual revenues	$ 5,157.1	$ 623.4	$ 59.2
Mark-to-market revenues	51.4	238.1	175.8
Fuel and purchased energy expenses	(4,830.7)	(583.8)	(49.7)
Revenues less fuel and purchased energy expenses	$ 377.8	$ 277.7	$185.3

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

Accrual Revenues and Fuel and Purchased Energy Expenses
We provide the changes in revenues and fuel and purchased energy expenses in 2003 compared to 2002 and in 2002 compared to 2001 in the following table:

	2003 vs. 2002		2002 vs. 2001	
	Increases in revenues	Increases in fuel and purchased energy expenses	Increases in revenues	Increases in fuel and purchased energy expenses
		(In millions)		
Wholesale accrual activities	$2,133.3	$1,912.6	$228.0	$238.2
Acquisitions	2,400.4	2,334.3	336.2	295.9
Total increase	$4,533.7	$4,246.9	$564.2	$534.1

Our accrual revenues and fuel and purchased energy expenses increased in 2003 compared to 2002 mostly because of the re-designation of our load-serving activities to accrual, including the adoption of EITF 02-3, combined with increased wholesale accrual origination activities, primarily in Texas and New England, and the acquisitions of NewEnergy and Alliance. Our accrual revenues also increased due to additional product and service offerings, and includes approximately $33 million of pre-tax gains on contract restructurings. We discuss the implications of EITF 02-3 in more detail in the *Critical Accounting Policies* section and in *Note 1*.

Our accrual revenues and fuel and purchased energy expenses increased in 2002 primarily due to the re-designation of our Texas and New England load-serving activities to accrual and the acquisition of NewEnergy in September 2002. We discuss the re-designation of Texas and New England below.

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

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

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

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

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

and associated power purchase agreements entered into since the second quarter of 2002.

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

Mark-to-Market Revenues

Mark-to-market revenues include net gains and losses from origination and risk management activities for which we use the mark-to-market method of accounting. We discuss these activities and the mark-to-market method of accounting in more detail in the *Critical Accounting Policies* section and in *Note 1*. We also discuss the implications of EITF 02-3 on the mark-to-market method of accounting in the *Critical Accounting Policies* section and in *Note 1*.

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

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

Mark-to-market revenues were as follows:

	2003	2002	2001
		(In millions)	
Unrealized revenues			
Origination gains	$ 62.3	$160.4	$227.0
Risk management			
Unrealized changes in fair value	(10.9)	66.9	(55.7)
Changes in valuation techniques	—	10.8	4.5
Reclassification of settled contracts to realized	(123.5)	(45.4)	(19.7)
Total risk management	(134.4)	32.3	(70.9)
Total unrealized revenues	(72.1)	192.7	156.1
Realized revenues	123.5	45.4	19.7
Total mark-to-market revenues	$ 51.4	$238.1	$175.8

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

Origination gains represent the initial fair value recognized on these structured transactions. The recognition of origination gains is dependent on the existence of observable market data that validates the initial fair value of the contract. For the year ending December 31, 2003, origination gains contributed $62.3 million before tax. Origination gains arose from 14 transactions completed in 2003, of which no transaction individually contributed in excess of $10 million pre-tax. The amount of 2003 origination gains decreased significantly as compared to 2002 due to the implementation of EITF 02-3.

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

Risk management revenues represent both realized and unrealized gains and losses from changes in the value of our entire portfolio. We discuss the changes in mark-to-market revenues below. We show the relationship between our revenues and the change in our net mark-to-market energy asset later in this section.

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

Mark-to-market revenues decreased $186.7 million in 2003 compared to 2002 mostly because of lower revenues from origination transactions, net losses from risk management activities compared to net gains in the prior year, and the reclassification of revenues from settled contracts to realized revenues. The lower level of origination transactions primarily reflects the continuing reduction of the portion of our activities subject to mark-to-market accounting. The decrease in risk management revenues is primarily due to mark-to-market revenue associated with the restructuring of our High Desert contract with the CDWR that had a positive impact in 2002, unfavorable changes in regional power prices, price volatility, and the impact of mark-to-market losses on economic hedges that did not qualify for hedge accounting treatment as discussed in more detail below.

With the implementation of EITF 02-3 in the first quarter of 2003, all of our load-serving contracts were converted to accrual accounting. However, several economically effective hedges on these positions did not qualify for accrual accounting treatment under SFAS No. 133 and remained in the mark-to-market portfolio. In 2003, increasing forward prices shifted value between accrual load-serving positions and

associated mark-to-market hedges producing a timing difference in the recognition of earnings on related transactions. As a result, we recorded a $47.4 million pre-tax loss on the mark-to-market hedges during 2003. This mark-to-market loss will be offset by the end of 2006 as we realize the related accrual load-serving positions in cash.

Mark-to-market revenues increased $62.3 million during 2002 compared to 2001 mostly because of net gains from risk management activities compared to net losses in the prior year, partially offset by lower revenues from origination transactions. The increase in risk management revenues is primarily due to the absence of mark-to-market losses recorded in 2001 on Texas trading activities designated as non-trading in 2002, favorable changes in regional power prices, price volatility, and other factors in 2002 compared to 2001. The decrease in origination revenues reflects the use of accrual accounting for new load-serving transactions originated beginning in the second quarter of 2002, the impact of applying the EITF 02-3 guidance on recording gains at the time of contract origination as previously described in the *Critical Accounting Policies* section, and fewer individually significant transactions in 2002 as compared to 2001.

Mark-to-Market Energy Assets and Liabilities

Our mark-to-market energy assets and liabilities are comprised of derivative contracts, and in 2002, prior to the implementation of EITF 02-3, were comprised of a combination of derivative and non-derivative (physical) contracts. The non-derivative assets and liabilities primarily related to load-serving activities originated prior to the shift to accrual accounting in 2002. While some of our mark-to-market contracts represent commodities or instruments for which prices are available from external sources, other commodities and certain contracts are not actively traded and are valued using other pricing sources and modeling techniques to determine expected future market prices, contract quantities, or both. We discuss our modeling techniques later in this section.

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

At December 31,	2003	2002
	(In millions)	
Current Assets	$555.2	$ 759.4
Noncurrent Assets	286.9	926.8
Total Assets	842.1	1,686.2
Current Liabilities	541.5	709.6
Noncurrent Liabilities	283.0	460.0
Total Liabilities	824.5	1,169.6
Net mark-to-market energy asset	$ 17.6	$ 516.6

The following are the primary sources of the change in net mark-to-market energy asset during 2003 and 2002:

	2003		2002	
		(In millions)		
Fair value beginning of year		$516.6		$ 418.4
Changes in fair value recorded as revenues				
Origination gains	$ 62.3		$160.4	
Unrealized changes in fair value	(10.9)		66.9	
Changes in valuation techniques	—		10.8	
Reclassification of settled contracts to realized	(123.5)		(45.4)	
Total changes in fair value recorded as revenues		(72.1)		192.7
Cumulative effect impact of EITF 02-3		(379.4)		—
Contracts designated as normal purchases/sales and hedges upon implementation of EITF 02-3		(58.2)		—
Contract exchange		(68.9)		—
Changes in fair value recorded as operating expenses		—		9.0
Changes in value of exchange-listed futures and options		(8.4)		(8.5)
Net change in premiums on options		99.3		(40.1)
Texas contracts re-designated as non-trading		—		(63.3)
Other changes in fair value		(11.3)		8.4
Fair value at end of year		$ 17.6		$ 516.6

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

- Origination transactions represent the initial unrealized fair value at the time these contracts are executed to the extent permitted by applicable accounting rules, including EITF 02-3 effective January 1, 2003.
- Unrealized changes in fair value represent unrealized changes in commodity prices, the volatility of options on commodities, the time value of options, and other valuation adjustments.
- Changes in valuation techniques represent improvements in estimation techniques, including modeling and other statistical enhancements used to value our portfolio to reflect more accurately the economic value of our contracts.
- Reclassification of settled contracts to realized represents the portion of previously unrealized amounts settled during the period and recorded as realized revenues.

The net mark-to-market energy asset also changed due to the following items recorded in accounts other than revenue:

- The cumulative effect impact of EITF 02-3 represents the non-derivative portion of the net asset that was removed from our Consolidated Balance Sheets as a cumulative effect of change in accounting principle effective January 1, 2003 as required by EITF 02-3.
- Contracts designated as normal purchases/sales and hedges upon implementation of EITF 02-3 represents the portion of the net asset reclassified to "Other assets or liabilities" under the normal purchases/normal sales provisions of SFAS No. 133 or "Risk management assets or liabilities" under the cash-flow hedge provisions of SFAS No. 133 in connection with the implementation of EITF 02-3 effective January 1, 2003.

- Contract exchange represents the fair value of a contract previously included in "Mark-to-market energy assets" that we terminated in a nonmonetary exchange with a counterparty. At that time, we also terminated a hedge contract with the same counterparty that was recorded in "Risk management liabilities." In exchange, we entered into a new cash-flow hedge transaction with the counterparty that we recorded at an amount equal to the fair value of the terminated contracts.
- Changes in fair value recorded as operating expenses represent accruals for future incremental expenses in connection with servicing origination transactions. While these accruals are recorded as part of the fair value of the net mark-to-market energy asset, they are reflected in our Consolidated Statements of Income as expenses rather than revenues.
- Changes in value of exchange-listed futures and options are adjustments to remove unrealized revenue from exchange-traded contracts that are included in risk management revenues. The fair value of these contracts is recorded in "Accounts receivable" rather than "Mark-to-market energy assets" in our Consolidated Balance Sheets because these amounts are settled through our margin account with a third-party broker.
- Net changes in premiums on options reflects the accounting for premiums on options purchased as an increase in the net mark-to-market energy asset and premiums on options sold as a decrease in the net mark-to-market energy asset.

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

The settlement terms of our net mark-to-market energy asset and sources of fair value as of December 31, 2003 are as follows:

	Settlement Term							
	2004	2005	2006	2007	2008	2009	Thereafter	Fair Value
	(In millions)							
Prices provided by external sources (1)	$13.2	$(1.8)	$ 76.4	$ (0.6)	$ —	$ —	$ —	$ 87.2
Prices based on models	0.5	(1.5)	(73.8)	12.4	(0.8)	(2.6)	(3.8)	(69.6)
Total net mark-to-market energy asset	$13.7	$(3.3)	$ 2.6	$11.8	$ (0.8)	$ (2.6)	$ (3.8)	$ 17.6

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

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

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

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

- forward purchases and sales of electricity during peak hours for delivery terms primarily through 2005, but up to 2007, depending upon the region,
- forward purchases and sales of electricity during off-peak hours for delivery terms primarily through 2005, but up to 2007, depending upon the region,
- options for the purchase and sale of electricity during peak hours for delivery terms through 2004, depending upon the region,
- forward purchases and sales of electric capacity for delivery terms through 2005,
- forward purchases and sales of natural gas, coal and oil for delivery terms through 2006, and
- options for the purchase and sale of natural gas, coal and oil for delivery terms through 2005.

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

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

- observable market prices,

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

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

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

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

The fair values in the table represent expected future cash flows based on the level of forward prices and volatility factors as of December 31, 2003 and could change significantly as a result of future changes in these factors. Additionally, because the depth and liquidity of the power markets vary substantially between regions and time periods, the prices used to determine fair value could be affected significantly by the volume of transactions executed.

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

Other

	2003	2002	2001
		(In millions)	
Revenues	$45.1	$56.4	$80.5

Our merchant energy business holds up to a 50% ownership interest in 25 operating domestic energy projects that consist of electric generation, fuel processing, or fuel handling facilities. Of these 25 projects, 18 are "qualifying facilities" that receive certain exemptions and pricing under the Public Utility Regulatory Policy Act of 1978 based on the facilities' energy source or the use of a cogeneration process. In addition, we own 100% of a geothermal generating facility in Hawaii. Earnings from our investments were $2.0 million in 2003, $9.1 million in 2002 and $23.1 million in 2001.

The decrease in revenues in 2003 compared to 2002 was due to lower revenues from our California projects because we reversed certain credit reserves that totaled $9.1 million during the first quarter of 2002, as we began receiving payments from the California utilities, which had a positive impact in 2002, partially offset by a geothermal project generating at a higher capacity in 2003. The decrease in revenues in 2002 compared to 2001 was due to a geothermal project generating at a lower capacity and lower revenues from our California projects.

At December 31, 2003, our investment in qualifying facilities and domestic power projects consisted of the following:

Book Value at December 31,	2003	2002
	(In millions)	
Project Type		
Coal	$130.5	$133.9
Hydroelectric	57.3	62.6
Geothermal*	56.0	151.4
Biomass	51.4	52.6
Fuel Processing	22.5	23.2
Solar	10.5	10.5
Total	$328.2	$434.2

* *During 2003, we acquired the minority interest from our partner in a geothermal project and removed the equity-method investment in the project and consolidated the assets and liabilities of the project in our Consolidated Balance Sheets.*

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

Currently, we are re-evaluating our strategy regarding our geothermal generating facility, which we obtained control by purchasing our partner's interest in December 2003. Upon obtaining control, we removed our equity-method investment and included the assets and liabilities in our Consolidated

Balance Sheets. As of December 31, 2003, this generating facility had property, plant and equipment with a net book value of approximately $137 million.

The reevaluation of our strategy has included soliciting bids to determine the level of interest in the project, and if we determine that offers to purchase the project would provide more attractive cash flows than under our current hold and use strategy, we may decide to dispose of the project.

While we have not completed the reevaluation of our strategy, based upon the number and level of bids received, management has determined that disposal of the project is more likely than not to occur. As a result, we evaluated our facility for impairment as of December 31, 2003, in accordance with SFAS No. 144, and determined that the assets were not impaired. We expect to complete the reevaluation of our strategy in the first half of 2004, and if we ultimately dispose of the plant, the actual proceeds received could be less than the carrying value of the plant resulting in a loss that could be material.

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

Given the need for electric power and the desire for renewable resource technologies, we believe California will continue to subsidize the use of renewable energy to make these projects economical to operate. However, should the California legislation fail to adequately support the renewable energy initiatives, our equity-method investments in these types of projects could become impaired under the provisions of APB No. 18, and any losses recognized could be material.

If our strategy were to change from an intent to hold to an intent to sell for any of our equity-method investments in qualifying facilities or power projects, we would need to adjust their book value to fair value, and that adjustment could be material. If we were to sell these investments in the current market, we may have losses that could be material.

Operations and Maintenance Expenses

Our merchant energy business operations and maintenance expenses increased $183.5 million in 2003 compared to 2002 mostly due to the following:

- an increase of $81.5 million due to the acquisitions of NewEnergy in September 2002 and Alliance in December 2002,
- an increase in costs related to our wholesale marketing and risk management operation as a result of growth of this operation,
- an increase of $22.7 million at Nine Mile Point, including higher costs associated with the refueling outage of Unit 1 in 2003 compared to the 2002 refueling outage of Unit 2. Since we own 100% of Unit 1, we incurred all outage costs compared to 82% of costs for Unit 2,
- costs of $17.8 million related to our High Desert facility that commenced operations in the second quarter of 2003, and
- higher compensation and other inflationary costs.

These increases were partially offset by cost reductions due to productivity initiatives including our corporate-wide workforce reduction programs.

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

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

These increases were partially offset by the following:

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

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

Our merchant energy business recognized expenses associated with our workforce reduction efforts, impairment losses and other costs, contract termination related costs, and a net loss on sales of assets as discussed in more detail in *Note 2.*

Depreciation and Amortization Expense
Merchant energy depreciation and amortization expense decreased $13.3 million in 2003 compared to 2002 mostly because of the adoption of SFAS No. 143.

Under SFAS No. 143, a portion of the decommissioning amortization is included as "Accretion of asset retirement obligations" expense beginning in 2003 as discussed below. In addition, beginning in 2003 we no longer include the expected net future costs of removal as a component of depreciation expense. These decreases were partially offset by higher depreciation expense related to new generating facilities that commenced operations in mid-2002 and High Desert that commenced operations in 2003.

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

Accretion of Asset Retirement Obligations
On January 1, 2003, we adopted SFAS No. 143 that requires the accretion of the asset retirement obligation liability due to the passage of time until the liability is settled. Accordingly, we recognized $42.7 million of accretion expense in 2003. We discuss SFAS No. 143 in *Note 1*.

Taxes Other Than Income Taxes
Merchant energy taxes other than income taxes increased $19.5 million in 2003 compared to 2002 mostly because of gross receipt taxes associated with NewEnergy and property taxes on new generating facilities.

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

Regulated Electric Business
As discussed in the *Electric Competition—Maryland* section, our regulated electric business was significantly impacted by the July 1, 2000 implementation of customer choice.

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

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

Results

	2003	2002	2001
		(In millions)	
Revenues	$1,921.6	$1,966.0	$2,040.0
Electric fuel and purchased energy	(1,023.5)	(1,080.7)	(1,192.8)
Operations and maintenance expenses	(297.4)	(252.4)	(258.7)
Workforce reduction costs	(0.6)	(34.0)	(55.7)
Depreciation and amortization	(181.7)	(174.2)	(173.3)
Taxes other than income taxes	(137.9)	(137.0)	(139.5)
Income from Operations	$ 280.5	$ 287.7	$ 220.0
Net Income	$ 107.5	$ 99.3	$ 50.9
Special Items Included in Operations (after-tax)			
Workforce reduction costs	$ (0.4)	$ (20.5)	$ (33.6)

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

Net income from the regulated electric business increased in 2003 compared to 2002 mostly because of:

- lower workforce reduction costs,
- lower interest expense, and
- cost reductions resulting from our corporate-wide workforce reduction programs and other productivity initiatives.

These favorable results were partially offset by distribution service restoration expenses related to Hurricane Isabel and other major storms in 2003. Total distribution service restoration expenses related to Hurricane Isabel were $22.2 million after-tax, which included $19.4 million after-tax of incremental expenses.

Net income from the regulated electric business increased in 2002 compared to 2001 mostly because of the following:

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

Electric Revenues
The changes in electric revenues in 2003 and 2002 compared to the respective prior year were caused by:

	2003	2002
	(In millions)	
Distribution sales volumes	**$ 3.0**	$ 32.7
Standard offer service	**(54.2)**	(70.2)
Fuel rate surcharge	**—**	(43.2)
Total change in electric revenues from electric system sales	**(51.2)**	(80.7)
Other	**6.8**	6.7
Total change in electric revenues	**$(44.4)**	$(74.0)

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

The percentage changes in our electric system sales volumes, by type of customer, in 2003 and 2002 compared to the respective prior year were:

	2003	2002
Residential	**0.8%**	8.0%
Commercial	**2.1**	3.2
Industrial	**(3.0)**	0.7

In 2003, we distributed about the same amount of electricity to residential customers compared to 2002. We distributed more electricity to commercial customers mostly due to increased usage per customer. We distributed less electricity to industrial customers mostly due to lower usage by industrial customers.

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

Standard Offer Service
BGE provides standard offer service for customers that do not select an alternative generation supplier as discussed in the *Electric Competition—Maryland* section.

Standard offer service revenues decreased in 2003 compared to 2002 and decreased in 2002 compared to 2001 mostly because a majority of BGE's large commercial and industrial customers left standard offer service in the second quarter of 2002 and elected other electric generation suppliers. In 2003, these decreased revenues were partially offset by an increase in the standard offer service rate that BGE charges its customers. In 2002, these decreased revenues were partially offset by increased sales to residential customers mostly due to warmer summer weather and an increase in the standard offer service rate that BGE charges its customers.

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

Electric Fuel and Purchased Energy Expenses

	2003	2002	2001
		(In millions)	
Actual costs	**$1,023.5**	$1,080.7	$1,150.5
Recovery of costs deferred under electric fuel rate clause	**—**	—	42.3
Total electric fuel and purchased energy expenses	**$1,023.5**	$1,080.7	$1,192.8

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

BGE's actual costs of electricity purchased for resale expenses decreased in 2003 compared to 2002 and decreased in 2002 compared to 2001 mostly because large commercial and industrial customers left BGE's standard offer service and elected other electric generation suppliers as previously discussed in the *Standard Offer Service* section.

Electric Operations and Maintenance Expenses
Regulated electric operations and maintenance expenses increased $45.0 million in 2003 compared to 2002 mostly because of distribution service restoration expenses related to Hurricane Isabel of $36.8 million, which includes $4.7 million of non-incremental labor expenses, and distribution service restoration expenses related to other major storms. This increase also reflects higher benefit and inflationary costs, partially offset by lower uncollectible expenses and cost reductions resulting from our corporate-wide workforce reduction programs and other productivity initiatives.

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

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

Electric Depreciation and Amortization Expense
Regulated electric depreciation and amortization expense increased in 2003 compared to 2002 mostly because of accelerated amortization associated with the planned replacement of information technology assets.

Regulated electric depreciation and amortization expense was about the same during 2002 compared to 2001.

Regulated Gas Business

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

Results

	2003	2002	2001
		(In millions)	
Revenues	$ 726.0	$ 581.3	$ 680.7
Gas purchased for resale expenses	(445.8)	(316.7)	(401.3)
Operations and maintenance expenses	(98.0)	(102.9)	(104.3)
Workforce reduction costs	(0.1)	(1.3)	(1.3)
Depreciation and amortization	(46.6)	(47.4)	(47.7)
Taxes other than income taxes	(31.0)	(34.4)	(34.3)
Income from Operations	$ 104.5	$ 78.6	$ 91.8
Net Income	$ 43.0	$ 31.1	$ 37.5
Special Items Included in Operations (after-tax)			
Workforce reduction costs	$ (0.1)	$ (0.8)	$ (0.8)

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

Net income from our regulated gas business increased during 2003 compared to 2002 mostly because of:

- the reinstatement of a $7.7 million pre-tax regulatory asset following an order issued by the Maryland PSC, and
- the approval of $3.6 million pre-tax of property tax refund claims by the State of Maryland resulting from a reclassification of gas distribution pipeline from real property to personal property.

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

Gas Revenues

The changes in gas revenues in 2003 and 2002 compared to the respective prior year were caused by:

	2003	2002
	(In millions)	
Distribution sales volumes	$ 21.6	$ 1.4
Base rates	(1.3)	(2.9)
Weather normalization	(18.9)	(0.5)
Gas cost adjustments	132.4	(55.8)
Total change in gas revenues from gas system sales	133.8	(57.8)
Off-system sales	10.0	(38.8)
Other	0.9	(2.8)
Total change in gas revenues	$144.7	$(99.4)

Distribution Sales Volumes

The percentage changes in our distribution sales volumes, by type of customer, in 2003 and 2002 compared to the respective prior year were:

	2003	2002
Residential	13.8%	3.5%
Commercial	7.6	7.1
Industrial	(21.5)	(1.4)

We distributed more gas to residential and commercial customers during 2003 compared to 2002 mostly due to colder winter weather, an increased number of customers and increased usage per customer. We distributed less gas to industrial customers mostly due to decreased usage per customer.

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

Weather Normalization

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

Gas Cost Adjustments

We charge our gas customers for the natural gas they purchase from us using gas cost adjustment clauses set by the Maryland PSC as described in *Note 1*. However, under market-based rates, our actual cost of gas is compared to a market index (a measure of the market price of gas in a given period). The difference between our actual cost and the market index is shared equally between shareholders and customers. The shareholders' portion was about the same during 2003 as compared to 2002. The shareholders' portion decreased $3.7 million during 2002 compared to 2001.

Effective November 2001, the Maryland PSC approved an order that modifies certain provisions of the market-based rates incentive mechanism. These provisions require that BGE secure fixed-price contracts for at least 10%, but not more than 20%, of forecasted system supply requirements for the November through March period. These fixed price contracts are not subject to sharing under the market-based rates incentive mechanism.

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

Gas cost adjustment revenues increased during 2003 as compared to 2002 because we sold more gas at a higher price. Gas cost adjustment revenues decreased during 2002 compared to 2001 mostly because the gas we sold to non-delivery service customers was at a lower price, partially offset by more gas sold.

In December 2002, a Hearing Examiner from the Maryland PSC issued a proposed order disallowing $7.7 million of a previously established regulatory asset for certain credits that were over-refunded to customers through our market-based rates. BGE reserved the $7.7 million of disallowed fuel costs in the fourth quarter of 2002. In August 2003, the Maryland PSC issued an order authorizing us to recover the $7.7 million and we reinstated the regulatory asset.

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.

Revenues from off-system gas sales increased during 2003 compared to 2002 because we sold gas at a higher price, partially offset by less gas sold.

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

Gas Purchased For Resale Expenses

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

Gas costs increased during 2003 as compared to 2002 mostly because we purchased more gas at a higher price.

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

Gas Operations and Maintenance Expenses

Regulated gas operations and maintenance expenses decreased $4.9 million during 2003 as compared to 2002 mostly because of lower uncollectible expenses and cost reductions resulting from our corporate-wide workforce reduction programs and other productivity initiatives.

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

Workforce Reduction Costs

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

Other Nonregulated Businesses

Results

	2003	2002	2001
		(In millions)	
Revenues	$ 587.9	$ 537.4	$ 552.6
Operating expenses	(535.8)	(505.9)	(510.7)
Workforce reduction costs	(0.1)	(1.0)	(2.7)
Impairment losses and other costs	(0.6)	(10.8)	(111.9)
Depreciation and amortization	(21.2)	(16.6)	(23.2)
Taxes other than income taxes	(3.4)	(4.3)	(3.4)
Net gain on sales of investments and other assets	26.2	265.0	6.2
Income (Loss) from Operations	$ 53.0	$ 263.8	$ (93.1)
Net Income (Loss) Before Cumulative Effect of Change in Accounting Principle	12.2	$ 148.0	$ (99.1)
Cumulative Effect of Change in Accounting Principle	—	—	8.5
Net Income (Loss)	$ 12.2	$ 148.0	$ (90.6)
Special Items Included In Operations (after-tax)			
Net gain on sales of investments and other assets	$ 16.4	$ 169.1	$ 1.9
Impairment of real estate, senior-living, and other investments	(0.4)	(1.2)	(72.5)
Workforce reduction costs	(0.1)	(0.7)	(1.7)
Costs associated with exit of BGE Home merchandise stores	—	(6.1)	—
Total Special Items	$ 15.9	$ 161.1	$ (72.3)

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

Net income from our other nonregulated businesses decreased $135.8 million during 2003 compared to 2002 mostly because we recognized a $163.3 million after-tax gain on the sale of our investment in Orion in 2002 that had a positive impact in that period. This decrease was partially offset by the following 2003 transactions:

- a $13.1 million pre-tax gain on the sale of several parcels of real estate,
- a $9.5 million pre-tax charge associated with the exit of BGE Home merchandise stores in 2002 which had a negative impact in that period,
- a $7.2 million pre-tax gain on the sale of an oil tanker to the U.S. Navy,
- a $5.3 million pre-tax gain on the favorable settlement of a contingent obligation we had previously reserved relating to the sale of our Guatemalan power plant operation in the fourth quarter of 2001,
- a $0.6 million pre-tax gain on the sale of financial investments, and
- improved results from our international portfolio.

Net income from our other nonregulated businesses increased $238.6 million during 2002 compared to 2001 mostly because of the following:

- We recognized a $255.5 million pre-tax gain on the sale of our investment in Orion in 2002.
- We recorded impairment losses and other costs in 2001 that had a negative impact in that year.
- We recognized a loss on the sale of our Guatemalan operations in 2001 that had a negative impact in that year.
- We had higher earnings due to the growth of our energy services business and improved results from our international portfolio.

These increases were partially offset by the following:

- We recognized gains on the sale of securities in 2001 that had a positive impact in that year, including the $14.9 million pre-tax gain on the sale of one million shares of our Orion investment and $34.6 million pre-tax gains on the sale of securities by our financial investments operation.
- We recorded $9.5 million of pre-tax costs associated with the exit of BGE Home merchandise stores in 2002.
- We recorded impairment losses of $1.8 million pre-tax related to certain non-core assets in 2002.

We discuss our special items further in *Note 2*.

In addition, we recognized an $8.5 million after-tax, or $0.05 per share, gain for the cumulative effect of adopting SFAS No. 133 in the first quarter of 2001.

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

At December 31, 2003, our remaining land holdings total approximately 220 acres. Our remaining projects are partially or substantially developed. Our strategy is to hold and in some cases further develop these projects to increase their value. However, if we were to sell these projects in the current market, we may have losses that could be material, although the amount of the losses is hard to predict.

In addition, we initiated a liquidation program for our financial investments operation. Through December 31, 2003, we have liquidated approximately 90% of our investment portfolio.

While our intent is to dispose of these remaining non-core assets, market conditions and other events beyond our control may affect the actual sale of these assets. In addition, a future decline in the fair value of these assets could result in additional losses.

Consolidated Nonoperating Income and Expenses

Other Income

Other income decreased $11.4 million during 2003 compared to 2002 mostly because of lower interest income on temporary cash investments and higher earnings from consolidated investments where our ownership is less than 100%, which resulted in increased minority interest expense. Other income increased $29.2 million during 2002 compared to 2001 mostly because of interest income on the nuclear decommissioning trust fund transferred in connection with the acquisition of Nine Mile Point and income on temporary cash investments.

Other income for BGE decreased $16.1 million in 2003 as compared to 2002 mostly because of an increase in charitable contributions and because of lower interest income on temporary cash investments in the Constellation Energy cash pool. Other income for BGE increased $10.3 million during 2002 compared to 2001 mostly because of interest income on temporary cash investments in the Constellation Energy cash pool.

Fixed Charges

Total fixed charges increased $58.7 million during 2003 compared to 2002 mostly because we had lower capitalized interest due to our new generating facilities commencing operations and a higher level of debt outstanding, including the issuance of $550 million of debt in June 2003 that was used to refinance the High Desert Power Project lease.

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

Total fixed charges for BGE decreased $29.4 million during 2003 compared to 2002 mostly because of a lower level of debt outstanding and lower interest rates. Total fixed charges for BGE decreased $14.0 million during 2002 as compared to 2001 mostly because of a lower level of debt outstanding due to the repayment of maturing long-term debt.

Income Taxes

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

Pension Expense

Our actual return on our qualified pension plan assets was 23% for the year ended December 31, 2003. We assume an expected return on pension plan assets of 9% for the purpose of computing annual net periodic pension expense in accordance with SFAS No. 87, *Employers' Accounting for Pensions*. Differences between actual and expected returns are deferred along with other actuarial gains and losses and reflected in future net periodic pension expense in accordance with SFAS No. 87. Expected and actual returns on pension assets also are affected by plan contributions.

In 2003, we contributed $115 million to our pension plans. As of the date of this report, we contributed an additional $50 million to our pension plans in 2004. At December 31, 2003, we recorded an after-tax increase to equity of $12.6 million as a result of decreasing our additional minimum pension liability. We discuss our pension plans in more detail in *Note 7*.

Financial Condition

Cash Flows

The following table summarizes our 2003 cash flows by business segment, as well as our consolidated cash flows for 2003, 2002, and 2001. This table excludes the impact of the refinancing of the High Desert Power Project and the impact of changes in intercompany balances. We exclude the impact of the High Desert refinancing due to the fact that there was no net impact on cash. The financing source of cash we received from the issuance of debt was offset by the investing use of cash we incurred from terminating the lease. We discuss the refinancing of High Desert in more detail in the *Significant Events of 2003* section and in *Note 15.*

	2003 Segment Cash Flows			Consolidated Cash Flows		
	Merchant	Regulated	Other	2003	2002	2001
			(In millions)			
Operating Activities						
Net Income	$ 114.6	$ 150.5	$ 12.2	$ 277.3	$ 525.6	$ 90.9
Non-cash adjustments to net income	687.6	278.3	(18.1)	947.8	606.0	749.9
Changes in working capital	(10.9)	3.5	(57.9)	(65.3)	49.0	(288.4)
Pension and postemployment benefits*				(69.4)	(116.2)	55.3
Other	(75.3)	8.1	56.9	(10.3)	(44.4)	(34.4)
Net cash provided by (used in) operating activities	716.0	440.4	(6.9)	1,080.1	1,020.0	573.3
Investing activities (excluding $514.1 million related to the refinancing of the High Desert lease)						
Investments in property, plant and equipment	(333.3)	(291.3)	(33.4)	(658.0)	(831.9)	(1,302.5)
Acquisitions, net of cash acquired (excluding High Desert)	(32.5)	—	—	(32.5)	(221.4)	(382.7)
Contributions to nuclear decommissioning trust funds	(13.2)	—	—	(13.2)	(17.6)	(22.0)
Sale of investments and other assets	1.3	—	147.5	148.8	838.0	287.1
Other investments	(86.1)	1.8	(29.3)	(113.6)	(86.9)	(52.6)
Net cash (used in) provided by investing activities (excluding High Desert)	(463.8)	(289.5)	84.8	(668.5)	(319.8)	(1,472.7)
Cash flows from operating activities less cash flows from investing activities	$ 252.2	$ 150.9	$ 77.9	411.6	700.2	(899.4)
Financing Activities (excluding $514.1 million related to the refinancing of the High Desert lease)						
Net repayment of debt (excluding High Desert)*				(239.2)	(62.9)	396.4
Proceeds from issuance of common stock*				95.4	28.5	504.4
Common stock dividends paid*				(169.2)	(137.8)	(120.7)
Other*				7.7	14.6	9.0
Net cash (used in) provided by financing activities (excluding High Desert)				(305.3)	(157.6)	789.1
Net Increase (Decrease) in Cash and Cash Equivalents				$ 106.3	$ 542.6	$ (110.3)

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

Overview—2003 Compared to 2002

Cash flows from operating activities less cash flows from investing activities were $411.6 million in 2003 compared to $700.2 million in 2002. This decrease was primarily due to a reduction in proceeds from the sale of non-core assets of $689.2 million in 2003 compared to 2002. We discuss our sales of Orion and COPT in *Note 2.*

Excluding the impact of these non-core asset sales, cash flows from operating activities less cash flows from investing activities were as follows:

	2003	2002	Change
		(In millions)	
Cash flows from operating activities less cash flows from investing activities	$ 411.6	$ 700.2	$(288.6)
Less: cash flows from sale of investments and other assets	(148.8)	(838.0)	689.2
Net	$ 262.8	$(137.8)	$ 400.6

The $400.6 million increase in 2003 compared to 2002 was primarily due to lower investments in property, plant and equipment of $173.9 million, lower cash used for acquisitions, excluding High Desert, of $188.9 million, and an increase in cash provided by operating activities of $60.1 million.

Cash Flows from Operating Activities
Cash provided by operating activities was $1,080.1 million in 2003 compared to $1,020.0 million in 2002 and $573.3 million in 2001. Non-cash adjustments to net income were $341.8 million higher in 2003 compared to 2002. The increase in non-cash adjustments to net income was primarily due to the following:

- cumulative effects of changes in accounting principles of $198.4 million as a result of the adoption of SFAS No. 143 and EITF 02-3 in 2003, which had the effect of reducing net income but were non-cash transactions, and
- a decrease in the net gain on sales of investments and other assets of $235.1 million primarily due to the sale of our investment in Orion in 2002. We adjusted net income to exclude these gains and reflected the proceeds from these sales in the investing activities section.

These increases in non-cash adjustments to net income were offset in part by lower accruals for workforce reduction costs of $60.7 million in 2003 compared to 2002.

Changes in working capital had a negative impact of $65.3 million on cash flow from operations in 2003 compared to a positive impact of $49.0 million in 2002. The $114.3 million decrease was primarily due to the following uses of cash in 2003 compared to 2002:

- an increase in cash in 2002 due to the collection of approximately $85 million related to prepaid expenses and collateral at NewEnergy subsequent to our acquisition,
- a decline in accrued interest of approximately $50 million in 2003 compared to 2002 due to a shift in the timing of interest payments as a result of financings in 2002,
- an increase of approximately $40 million in fuel stocks and materials and supplies during 2003 primarily due to higher gas prices, which affected BGE's inventory levels,
- an increase of approximately $54 million in our accounts receivable balance primarily related to our merchant energy business as a result of increased business and High Desert commencing operations in 2003.

These items were partially offset by a source of cash in 2003 compared to 2002 due to an increase in accrued income taxes.

The increase in cash provided by operating activities in 2002 compared to 2001 was primarily due to higher net income and favorable changes in working capital.

Cash Flows from Investing Activities
Cash used in investing activities was $668.5 million in 2003, excluding the impact of the acquisition of the High Desert Power Project in 2003, compared to $319.8 million in 2002 and $1,472.7 million in 2001. The increase in cash used in 2003 compared to 2002 was primarily due to a decrease in cash proceeds from the sales of investments and other assets in 2003 because of the sale of Orion and COPT that generated $555.4 million in 2002. We discuss our sales of Orion and COPT in *Note 2*. These sales were partially offset by lower cash used for acquisitions in 2003 compared to 2002.

The decrease in cash used in investing activities in 2002 compared to 2001 was mostly due to cash proceeds from the sale of non-core assets and a decrease in capital spending due to the termination of all planned development projects.

Cash Flows from Financing Activities
Cash used in financing activities was $305.3 million in 2003, excluding the impact of refinancing the High Desert Power Project, compared to $157.6 million in 2002. The decrease in 2003 compared to 2002 was mostly due a higher repayment of debt in 2003 compared to 2002.

Cash provided by financing activities decreased $946.7 million in 2002 compared to 2001 mostly due to the issuance of common stock in 2001 and higher repayment of debt in 2002, partially offset by higher issuance of debt during 2002.

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

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

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

Available Sources of Funding

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

Constellation Energy

In addition to our cash balance, we have a commercial paper program under which we can issue short-term notes to fund our subsidiaries. At December 31, 2003, we had approximately $1.5 billion of credit under three facilities as discussed below.

In June 2003, Constellation Energy arranged a $447.5 million 364-day revolving credit facility and a $447.5 million three-year revolving credit facility replacing a maturing $640 million 364-day revolving credit facility and a maturing $188.5 million three-year revolving credit facility. We also have an existing $640 million revolving credit facility that expires in June 2005. We use these facilities to allow the issuance of commercial paper. In addition, we use the multi-year facilities to allow for the issuance of letters of credit.

These revolving credit facilities allow the issuance of letters of credit up to approximately $1.1 billion.

At December 31, 2003, letters of credit that totaled $507.1 million were issued under all of our facilities, which results in approximately $1.0 billion of unused credit facilities.

BGE

BGE maintains $200.0 million in annual committed credit facilities, expiring May through November 2004, in order to allow commercial paper to be issued. As of December 31, 2003, BGE had no outstanding commercial paper, which results in $200.0 million in unused credit facilities.

Other Nonregulated Businesses

BGE Home Products & Services maintains a program to sell up to $50 million of receivables. We expect to extend this program beyond the current expiration date in March 2004.

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

Capital Resources

Our actual consolidated capital requirements for the years 2001 through 2003, along with the estimated annual amount for 2004, are shown in the table below.

We will continue to have cash requirements for:

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

Capital requirements for 2004 and 2005 include estimates of spending for existing and anticipated projects. We continuously review and modify those estimates. Actual requirements may vary from the estimates included in the table below because of a number of factors including:

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

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

	2001	2002	2003	2004
		(In millions)		
Nonregulated Capital Requirements:				
Merchant energy (excludes acquisitions)				
Construction program	$ 697	$122	$ —	
Steam generators	53	83	59	
Reactor vessel head replacement	—	—	8	
Environmental controls	89	66	12	
Continuing requirements (including nuclear fuel)	205	370	340(A)	
Total merchant energy capital requirements	1,044	641	419	$445
Other nonregulated capital requirements	35	65	53	40
Total nonregulated capital requirements	1,079	706	472	485
Utility Capital Requirements:				
Regulated electric	180	167	236	215
Regulated gas	59	50	53	60
Total utility capital requirements	239	217	289	275
Total capital requirements	$1,318	$923	$761	$760

(A) The table above does not include the capital requirements and financing costs of approximately $40 million for the High Desert Power Project for the six months ended June 30, 2003. We discuss the acquisition of the High Desert Power Project in *Note 15*.

As of the date of this report, we have not completed our 2005 capital budgeting process, but expect our 2005 capital requirements to be approximately $650-750 million.

Capital Requirements

Merchant Energy Business

Our merchant energy business' capital requirements consist of its continuing requirements, including construction expenditures for improvements to generating plants, nuclear fuel costs, costs of complying with the Environmental Protection Agency (EPA), Maryland, and Pennsylvania nitrogen oxides (NOx) emissions regulations, and enhancements to our information technology infrastructure. We discuss the NOx regulations and timing of expenditures in *Note 12.*

Regulated Electric and Gas

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

Funding for Capital Requirements

Merchant Energy Business

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

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

We expect to fund acquisitions, including Ginna, with a mixture of debt and equity with an overall goal of maintaining a strong investment grade credit profile. Funding for this acquisition is expected to occur during 2004.

BGE

Funding for utility capital expenditures is expected from internally generated funds. During 2004, we expect our regulated utility business to generate sufficient cash flows from operations to meet BGE's operating requirements. If necessary, additional funding may be obtained from commercial paper issuances, available capacity under credit facilities, the issuance of long-term debt, trust preferred securities, or preference stock, and/or from time to time equity contributions from Constellation Energy. BGE also participates in a cash pool administered by Constellation Energy as discussed in *Note 16.*

Other Nonregulated Businesses

Funding for our other nonregulated businesses is expected from internally generated funds, commercial paper issuances, issuances of long-term debt of Constellation Energy, sales of securities and assets, and/or from time to time equity contributions from Constellation Energy. BGE Home Products & Services can continue to fund capital requirements through sales of receivables.

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

Contractual Payment Obligations and Committed Amounts

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

Our total contractual payment obligations as presented in the table on the next page increased $7.2 billion during 2003 compared to 2002 primarily due to:

- new presentation requirements resulting in the initial inclusion of interest payments of $3,976.6 million and postretirement and postemployment benefit obligations of $361.8 million,
- higher purchased capacity and energy obligations of $2,417.6 million under new power purchase agreements associated with revenue generating contracts with customers due to the growth of our merchant energy business, and
- higher other purchase obligations of $351.9 million, including newly executed turbine and software maintenance agreements.

Our total contractual payment obligations as of December 31, 2003 are shown in the following table:

	Payments				
	2004	2005-2006	2007-2008	Thereafter	Total
			(In millions)		
Contractual Payment Obligations					
Long-term debt:[1]					
Nonregulated					
Principal	$ 12.6	$ 327.6	$ 654.1	$2,744.9	$ 3,739.2
Interest	238.3	439.7	369.5	1,748.9	2,796.4
Total	250.9	767.3	1,023.6	4,493.8	6,535.6
BGE					
Principal	151.4	482.7	418.5	600.8	1,653.4
Interest	90.1	169.4	96.7	824.0	1,180.2
Total	241.5	652.1	515.2	1,424.8	2,833.6
BGE preference stock	—	—	—	190.0	190.0
Operating leases	22.1	38.8	26.6	117.2	204.7
Purchase obligations:[2]					
Purchased capacity and energy[3]	1,318.8	1,105.7	267.3	188.9	2,880.7
Fuel and transportation[4]	551.8	424.6	63.9	52.8	1,093.1
Other	76.7	48.8	40.7	218.9	385.1
Other noncurrent liabilities:					
Postretirement and postemployment benefits[5]	39.0	87.0	99.5	136.3	361.8
Other	2.6	2.7	1.6	—	6.9
Total contractual payment obligations	$2,503.4	$3,127.0	$2,038.4	$6,822.7	$14,491.5

1 Amounts in long-term debt reflect the original maturity date. Investors may require us to repay $387.0 million early through put options and remarketing features.

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

3 Our contractual obligations for purchased capacity and energy are shown on a gross basis for certain transactions, including both the fixed payment portions of tolling contracts and estimated variable payments under unit-contingent power purchase agreements. We have recorded $34.2 million of liabilities related to purchased capacity and energy obligations at December 31, 2003 in our Consolidated Balance Sheets.

4 We have recorded liabilities of $78.5 million related to fuel and transportation obligations at December 31, 2003 in our Consolidated Balance Sheets.

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

The table below presents our contingent obligations. Our contingent obligations increased $1.8 billion during 2003, primarily due to the issuance of additional letters of credit and guarantees by the parent company of subsidiary obligations to third parties in support of the growth of our merchant energy business. These amounts do not represent incremental consolidated Constellation Energy obligations; rather, they primarily represent parental guarantees of certain subsidiary obligations to third parties. Our calculation of the fair value of subsidiary obligations covered by the $3,975.4 million of parent company guarantees was $902.2 million at December 31, 2003. Accordingly, if the parent company was required to fund subsidiary obligations, the total amount at current market prices is $902.2 million.

	Expiration				
	2004	2005-2006	2007-2008	Thereafter	Total
			(In millions)		
Contingent Obligations					
Letters of credit	$ 506.5	$ 0.6	$ —	$ —	$ 507.1
Guarantees - competitive supply[1]	3,166.0	265.6	162.0	381.8	3,975.4
Other guarantees, net[2]	16.1	9.9	10.6	483.0	519.6
Total contingent obligations	$3,688.6	$276.1	$172.6	$864.8	$5,002.1

1 While the face amount of these guarantees is $3,975.4 million, we do not expect to fund the full amount. Our calculation of the fair value of obligations covered by these guarantees was $902.2 million at December 31, 2003.

2 Other guarantees in the above table are shown net of liabilities of $25.6 million recorded at December 31, 2003 in our Consolidated Balance Sheets.

Liquidity Provisions

We have certain agreements that contain provisions that would require additional collateral upon significant credit rating decreases in the Senior Unsecured Debt of Constellation Energy. Decreases in Constellation Energy's credit ratings would not trigger an early payment on any of our credit facilities. However, under counterparty contracts related to our wholesale marketing and risk management operation, where we are obligated to post collateral, we estimate that we would have additional collateral obligations based on downgrades to the following credit ratings for our Senior Unsecured Debt:

Credit Ratings Downgraded	Level Below Current Rating	Incremental Obligations	Cumulative Obligations
		(In millions)	
BBB/Baa2	1	$ 55	$ 55
BBB-/Baa3	2	135	190
Below investment grade	3	647	837

At December 31, 2003, we had approximately $1.2 billion of unused credit facilities and $721.3 million of cash available to meet potential requirements. However, based on market conditions and contractual obligations at the time of such a downgrade, we could be required to post collateral in an amount that could exceed the amounts specified above, and which could be material.

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

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

Certain credit facilities of Constellation Energy contain a provision requiring Constellation Energy to maintain a ratio of debt to capitalization equal to or less than 65%. At December 31, 2003, the debt to capitalization ratios as defined in the credit agreements were no greater than 55%.

Certain credit agreements of BGE contain provisions requiring BGE to maintain a ratio of debt to capitalization equal to or less than 65%. At December 31, 2003, the debt to capitalization ratio for BGE as defined in these credit agreements was 50%. At December 31, 2003, no amount is outstanding under these agreements.

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

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

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

Off-Balance Sheet Arrangements

For financing and other business purposes, we utilize certain off-balance sheet arrangements that are not reflected in our Consolidated Balance Sheets. Such arrangements do not represent a significant part of our activities or a significant ongoing source of financing. We use these arrangements when they enable us to obtain financing or execute commercial transactions on favorable terms. As of December 31, 2003, we have no material off-balance sheet arrangements including:

- guarantees with third-parties that are subject to the initial recognition and measurement requirements of FASB Interpretation No. 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness to Others.*
- retained interests in assets transferred to unconsolidated entities,
- derivative instruments indexed to our common stock, and classified as equity, or
- variable interests in unconsolidated entities that provide financing, liquidity, market risk or credit risk support, or engage in leasing, hedging or research and development services.

We discuss our guarantees in *Note 12*.

Market Risk

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

Interest Rate Risk

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

Principal Payments and Interest Rate Detail by Contractual Maturity Date

	2004	2005	2006	2007	2008	Thereafter	Total	Fair value at Dec. 31, 2003
				(Dollar amounts in millions)				
Short-term debt								
Variable-rate debt	$ 9.6	$ —	$ —	$ —	$ —	$ —	$ 9.6	$ 9.6
Average interest rate	3.11%	—	—	—	—	—	3.11%	
Long-term debt								
Variable-rate debt	$ 15.0	$ 12.8	$102.0	$ 10.1	$ 10.5	$ 172.8	$ 323.2	$ 323.2
Average interest rate	3.61%	3.74%	1.59%	5.50%	5.72%	1.48%	1.96%	
Fixed-rate debt	$149.0(A)	$343.0	$352.5	$729.5	$322.5	$3,172.9	$5,069.4	$5,723.5
Average interest rate	5.70%	7.71%	5.53%	6.54%	5.82%	6.33%	6.38%	

(A) Amount excludes $387.0 million of long-term debt that contains certain put options under which lenders could potentially require us to repay the debt prior to maturity of which $179.2 million is classified as current portion of long-term debt in our Consolidated Balance Sheets and in our Consolidated Statements of Capitalization.

Commodity Risk

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

Merchant Energy Business

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

Commodity Prices

Commodity price risk arises from the potential for changes in the price of, and transportation costs for, electricity, natural gas, coal, and other commodities; the volatility of commodity prices; and changes in interest rates and foreign exchange rates. A number of factors associated with the structure and operation of the energy markets significantly influence the level and volatility of prices for energy commodities and related derivative products. We use such commodities and contracts in our merchant energy business, and if we do not properly hedge the associated financial exposure, this commodity price volatility could affect our earnings. These factors include:

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

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

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

As a result of declines in BGE's standard offer service load and approximately 3,800 MW of natural gas-fired peaking and combined cycle generating facilities placed in service between 2001 and 2003, we have an amount of generating capacity that is subject to future changes in wholesale electricity prices. Additionally, we have fuel requirements that are subject to future changes in coal, natural gas, and oil prices. Our power generation facilities purchase fuel under contracts or on the spot market. Fuel prices may be volatile and the price that can be obtained from power sales may not change at the same rate or in the same direction as changes in fuel costs.

Supply and Demand Risk

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

Operations Risk

Operations risk is the risk that a generating plant will not be available to produce energy and the risks related to physical delivery of energy to meet our customers' needs. For 2004, we expect to use the majority of the generating capacity controlled by our merchant energy business to provide standard offer service to BGE or to serve the load requirements of the sellers of Nine Mile Point.

If one or more of our generating facilities is not able to produce electricity when required due to operational factors, we may have to forego sales opportunities or fulfill fixed-price sale commitments through the operation of other more costly generating facilities or through the purchase of energy in the wholesale market at higher prices.

Our nuclear plants produce electricity at a relatively low marginal cost. As a result, the costs of replacement energy associated with outages at these plants can be significant. If an unplanned outage were to occur during the summer or winter when demand was at a high level, the replacement power costs could have a material adverse impact on our financial results.

Risk Management

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

- forward contracts, which commit us to purchase or sell energy commodities in the future;
- futures contracts, which are exchange-traded standardized commitments to purchase or sell a commodity or financial instrument, or to make a cash settlement, at a specific price and future date;

- swap agreements, which require payments to or from counterparties based upon the differential between two prices for a predetermined contractual (notional) quantity; and
- option contracts, which convey the right to buy or sell a commodity, financial instrument, or index at a predetermined price.

The objectives for entering into such hedges include:

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

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

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

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

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

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

The value at risk amount represents the potential pre-tax loss in the fair value of our wholesale marketing and risk management mark-to-market energy assets and liabilities over one and ten-day holding periods. Our value at risk for 2003 and 2002 were as follows:

For the year ended December 31,	2003	2002
	(In millions)	
99% Confidence Level, One-Day Holding Period		
Year end	$ 3.7	$ 4.8
Average	6.6	10.0
High	13.3	21.7
Low	2.7	2.7
95% Confidence Level, One-Day Holding Period		
Year end	$ 2.8	$ 3.6
Average	5.0	7.6
High	10.1	16.6
Low	2.1	2.1
95% Confidence Level, Ten-Day Holding Period		
Year end	$ 8.8	$11.4
Average	15.9	24.1
High	32.0	52.4
Low	6.5	6.5

Based on a 99% confidence interval, we would expect a one-day change in the fair value of the portfolio greater than or equal to the daily value at risk approximately once in every 100 days. In 2003, we experienced five instances where the actual daily mark-to-market change in portfolio value exceeded the predicted value at risk. This is primarily attributable to higher volatility of power and fuel prices experienced during 2003. On average, we expect to experience a change in value to our portfolio greater than our value at risk approximately 3 times in a calendar year. However, published market studies conclude that exceeding daily value at risk less than 7 times in a one-year period is considered consistent with a 99% confidence interval.

The table above is the value at risk associated with our wholesale marketing and risk management operation's mark-to-market energy assets and liabilities, including both trading and non-trading activities. The following table details our value at risk for the trading portion of our wholesale marketing and risk management mark-to-market energy assets and liabilities over a one-day holding period at a 99% confidence level for 2003 and 2002:

At December 31,	2003	2002
	(In millions)	
Average	$ 4.6	$ 3.6
High	10.9	15.4

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

Regulated Electric Business

Effective July 1, 2000, BGE's residential base rates are frozen for a six year period, and its commercial and industrial base rates are frozen for a four year period. The generation and transmission components of rates are frozen for different time periods depending on the service options selected by those customers. We discuss the impact on base rates beyond 2004 in the *Electric Competition—Maryland* section. Our wholesale marketing and risk management operation provides BGE with 100% of the energy and capacity required to meet its commercial and industrial standard offer service obligations through June 30, 2004, and 100% of the energy and capacity to meet its residential standard offer service obligations through June 30, 2006. BGE will obtain its supply for standard offer service to its commercial and industrial customers beginning July 1, 2004, and to its residential customers beginning July 1, 2006, through a competitive wholesale bidding process as discussed in the *Electric Competition—Standard Offer Service—Provider of Last Resort (POLR)* section.

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

Regulated Gas Business

Our regulated gas business may enter into gas futures, options, and swaps to hedge its price risk under our market-based rate incentive mechanism and our off-system gas sales program. We discuss this further in *Note 13*. At December 31, 2003 and 2002, our exposure to commodity price risk for our regulated gas business was not material.

Credit Risk

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

Wholesale Credit Risk

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

During 2003, we continued to observe significant declines in the creditworthiness of several major participants in the wholesale energy markets. We continue to actively manage the credit portfolio of our wholesale marketing and risk management operation to attempt to reduce the impact of the general decline in the overall credit quality of the energy industry and the impact of a potential counterparty default. As of December 31, 2003 and 2002, the credit portfolio of our wholesale marketing and risk management operation had the following public credit ratings:

At December 31,	2003	2002
Rating		
Investment Grade[1]	75%	85%
Non-Investment Grade	4	3
Not Rated	21	12

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

The reduction in the percentage of counterparties with investment grade ratings to 75% in 2003 is primarily due to increased business activity with counterparties that do not have public credit ratings. These "Not Rated" counterparties include governmental entities, municipalities, cooperatives, power pools, other load-serving entities, and marketers for which we determine creditworthiness based on our internal credit ratings.

In addition to the credit ratings provided by the major credit rating agencies, we utilize internal credit ratings to evaluate the creditworthiness of our wholesale customers, including those companies that do not have public credit ratings. The following table provides the breakdown of the credit quality of our wholesale credit portfolio based on our internal credit ratings.

At December 31,	2003	2002
Investment Grade Equivalent	91%	95%
Non-Investment Grade	9	5

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

Rating	Total Exposure Before Credit Collateral	Credit Collateral	Net Exposure	Number of Counterparties Greater than 10% of Net Exposure	Net Exposure of Counterparties Greater than 10% of Net Exposure
	(Dollars in millions)				
Investment grade	$577	$ 38	$539	1	$90
Split rating	8	—	8	—	—
Non-investment grade	138	102	36	—	—
Internally rated—investment grade	224	110	114	—	—
Internally rated—non-investment grade	28	4	24	—	—
Total	$975	$254	$721	1	$90

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

Additionally, if a counterparty were to default and we were to liquidate all contracts with that entity, our credit loss would include the loss in value of mark-to-market contracts, the amount owed for settled transactions, and additional payments, if any, we would have to make to settle unrealized losses on accrual contracts.

Retail Credit Risk

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

Retail credit risk is managed through established credit policies, monitoring customer exposures, a diversified portfolio with no significant concentration (customer or industry), and the use of credit mitigation measures such as letters of credit or prepayment arrangements.

During 2003, we did not experience a material change in the credit quality of our retail credit portfolio compared to 2002. Retail credit quality is dependent on the economy and the ability of our customers to manage through unfavorable economic cycles and other market changes. If the business environment were to be negatively affected by changes in economic or other market conditions, our retail credit risk may be adversely impacted.

Equity Price Risk

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

A hypothetical 10% decrease in equity prices would result in an approximate $75 million reduction in the fair value of our financial investments that are classified as trading or available-for-sale securities. In 2003, the value of our defined benefit pension plan assets increased by approximately $185 million due to advances in the markets in which plan assets are invested. We describe our financial investments in more detail in *Note 4*, and our pension plans in *Note 7*.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

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

REPORT OF MANAGEMENT

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

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

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

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

E. Follin Smith
Executive Vice-President and Chief Financial Officer

REPORT OF INDEPENDENT AUDITORS

To the Board of Directors and Shareholders of Constellation Energy Group, Inc. and Baltimore Gas and Electric Company

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a) 1. present fairly, in all material respects, the financial position of Constellation Energy Group, Inc. and Subsidiaries and of Baltimore Gas and Electric Company and Subsidiaries at December 31, 2003 and 2002, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2003 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a) 2. of this Form 10-K presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and the financial statement schedule are the responsibility of the Companies' management; our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

We have also previously audited, in accordance with auditing standards generally accepted in the United States of America, the consolidated balance sheets and statements of capitalization of Constellation Energy Group, Inc. and Subsidiaries and of Baltimore Gas and Electric Company and Subsidiaries as of December 31, 2001, 2000 and 1999, and the related consolidated statements of income, cash flows, and common shareholders' equity and comprehensive income for the years ended December 31, 2000 and 1999 (none of which are presented herein); and we expressed unqualified opinions on those consolidated financial statements. In our opinion, the information set forth in the Summary of Operations and Summary of Financial Condition of Constellation Energy Group, Inc. included in the Selected Financial Data for each of the five years in the period ended December 31, 2003, and the information set forth in the Summary of Operations and Summary of Financial Condition of Baltimore Gas and Electric Company included in the Selected Financial Data for each of the five years in the period ended December 31, 2003, is fairly stated, in all material respects, in relation to the consolidated financial statements from which it has been derived.

As discussed in *Note 1* to the consolidated financial statements, in 2003, the Companies changed their method of accounting for recording asset retirement obligations pursuant to Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations*, and the accounting for certain energy contracts pursuant to Emerging Issues Task Force Issue 02-3, *Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities.* As discussed in *Note 1* to the consolidated financial statements, in 2001, the Companies changed their method of accounting for derivative and hedging activities pursuant to Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended by Statement of Financial Accounting Standards No. 138, *Accounting for Certain Derivative Instruments and Certain Hedging Activities (an amendment of FASB Statement No. 133).*

PricewaterhouseCoopers LLP
Atlanta, Georgia
January 28, 2004

CONSOLIDATED STATEMENTS OF INCOME

Constellation Energy Group, Inc. and Subsidiaries

Year Ended December 31,	2003	2002	2001
	(In millions, except per share amounts)		
Revenues			
Nonregulated revenues	$7,068.8	$2,190.6	$1,164.9
Regulated electric revenues	1,921.5	1,965.6	2,039.6
Regulated gas revenues	712.7	570.5	674.3
Total revenues	9,703.0	4,726.7	3,878.8
Expenses			
Operating expenses	7,863.3	3,073.6	2,392.2
Workforce reduction costs	2.1	62.8	105.7
Impairment losses and other costs	0.6	25.2	158.8
Contract termination related costs	—	—	224.8
Depreciation and amortization	479.0	481.0	419.1
Accretion of asset retirement obligations	42.7	—	—
Taxes other than income taxes	275.2	259.2	226.6
Total expenses	8,662.9	3,901.8	3,527.2
Net Gain on Sales of Investments and Other Assets	26.2	261.3	6.2
Income from Operations	1,066.3	1,086.2	357.8
Other Income	19.1	30.5	1.3
Fixed Charges			
Interest expense	340.8	312.3	283.2
Interest capitalized and allowance for borrowed funds used during construction	(13.8)	(44.0)	(57.6)
BGE preference stock dividends	13.2	13.2	13.2
Total fixed charges	340.2	281.5	238.8
Income Before Income Taxes	745.2	835.2	120.3
Income Taxes	269.5	309.6	37.9
Income Before Cumulative Effects of Changes in Accounting Principles	475.7	525.6	82.4
Cumulative Effects of Changes in Accounting Principles, Net of Income Taxes of $119.5 and $5.6 (see Note 1)	(198.4)	—	8.5
Net Income	$ 277.3	$ 525.6	$ 90.9
Earnings Applicable to Common Stock	$ 277.3	$ 525.6	$ 90.9
Average Shares of Common Stock Outstanding—Basic	166.3	164.2	160.7
Average Shares of Common Stock Outstanding—Assuming Dilution	166.7	164.2	160.7
Earnings Per Common Share Before Cumulative Effects of Changes in Accounting Principles—Basic	$ 2.86	$ 3.20	$ 0.52
Cumulative Effects of Changes in Accounting Principles	(1.19)	—	0.05
Earnings Per Common Share—Basic	$ 1.67	$ 3.20	$ 0.57
Earnings Per Common Share Before Cumulative Effects of Changes in Accounting Principles—Assuming Dilution	$ 2.85	$ 3.20	$ 0.52
Cumulative Effects of Changes in Accounting Principles	(1.19)	—	0.05
Earnings Per Common Share—Assuming Dilution	$ 1.66	$ 3.20	$ 0.57
Dividends Declared Per Common Share	$ 1.04	$ 0.96	$ 0.48

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

CONSOLIDATED BALANCE SHEETS

Constellation Energy Group, Inc. and Subsidiaries

At December 31,	2003	2002
	(In millions)	
Assets		
Current Assets		
Cash and cash equivalents	$ 721.3	$ 615.0
Accounts receivable (net of allowance for uncollectibles of $51.7 and $41.9, respectively)	1,563.0	1,244.1
Mark-to-market energy assets	555.2	759.4
Risk management assets	256.0	72.3
Materials and supplies	211.7	208.6
Fuel stocks	178.2	126.5
Acquired contracts, net of amortization	67.0	70.8
Prepaid taxes other than income taxes	62.4	57.1
Other	92.0	163.4
Total current assets	3,706.8	3,317.2
Investments and Other Assets		
Nuclear decommissioning trust funds	736.1	645.4
Investments in qualifying facilities and power projects	332.6	439.2
Mark-to-market energy assets	286.9	926.8
Risk management assets	269.9	88.8
Goodwill	144.0	115.9
Acquired contracts, net of amortization	105.8	64.0
Other	238.0	253.1
Total investments and other assets	2,113.3	2,533.2
Property, Plant and Equipment		
Regulated property, plant and equipment		
Plant in service	5,131.7	4,952.4
Construction work in progress	130.5	118.3
Plant held for future use	4.5	4.5
Total regulated property, plant and equipment	5,266.7	5,075.2
Nonregulated generation property, plant and equipment	7,769.1	6,811.9
Other nonregulated property, plant and equipment	340.9	242.0
Nuclear fuel (net of amortization)	202.9	224.8
Accumulated depreciation	(3,978.1)	(3,694.3)
Net property, plant and equipment	9,601.5	8,659.6
Deferred Charges		
Regulatory assets (net)	229.5	297.3
Other	149.6	136.0
Total deferred charges	379.1	433.3
Total Assets	$15,800.7	$14,943.3

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

CONSOLIDATED BALANCE SHEETS

Constellation Energy Group, Inc. and Subsidiaries

At December 31,	2003	*2002*
	(In millions)	
Liabilities and Equity		
Current Liabilities		
Short-term borrowings	$ 9.6	$ 10.5
Current portion of long-term debt	343.2	426.2
Accounts payable	1,167.7	943.4
Customer deposits and collateral	181.7	102.8
Mark-to-market energy liabilities	541.5	709.6
Risk management liabilities	140.4	20.1
Accrued taxes	127.2	15.0
Accrued interest	83.1	95.5
Dividends declared	46.8	42.8
Other	266.5	298.6
Total current liabilities	2,907.7	2,664.5
Deferred Credits and Other Liabilities		
Deferred income taxes	1,384.4	1,330.7
Mark-to-market energy liabilities	283.0	460.0
Risk management liabilities	282.3	149.5
Asset retirement obligations	595.9	594.1
Postretirement and postemployment benefits	361.8	352.8
Net pension liability	225.7	334.6
Deferred investment tax credits	78.4	85.7
Other	198.4	199.9
Total deferred credits and other liabilities	3,409.9	3,507.3
Capitalization (See Consolidated Statements of Capitalization)		
Long-term debt	5,039.2	4,613.9
Minority interests	113.4	105.3
BGE preference stock not subject to mandatory redemption	190.0	190.0
Common shareholders' equity	4,140.5	3,862.3
Total capitalization	9,483.1	8,771.5
Commitments, Guarantees, and Contingencies (see Note 12)		
Total Liabilities and Equity	$15,800.7	$14,943.3

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

CONSOLIDATED STATEMENTS OF CASH FLOWS

Constellation Energy Group, Inc. and Subsidiaries

Year Ended December 31,	2003	2002	2001
		(In millions)	
Cash Flows From Operating Activities			
Net income	$ 277.3	$ 525.6	$ 90.9
Adjustments to reconcile to net cash provided by operating activities			
Cumulative effects of changes in accounting principles	198.4	—	(8.5)
Depreciation and amortization	600.0	548.0	468.9
Accretion of asset retirement obligations	42.7	—	—
Deferred income taxes	109.2	148.3	(26.5)
Investment tax credit adjustments	(7.3)	(7.9)	(8.1)
Deferred fuel costs	(10.1)	23.9	37.6
Pension and postemployment benefits	(69.4)	(116.2)	55.3
Net gain on sales of investments and other assets	(26.2)	(261.3)	(6.2)
Workforce reduction costs	2.1	62.8	105.7
Impairment losses and other costs	0.6	25.2	158.8
Contract termination related costs	—	—	26.2
Equity in earnings of affiliates less than dividends received	38.4	67.0	2.0
Changes in			
Accounts receivable	(291.0)	(236.8)	53.7
Mark-to-market energy assets and liabilities	29.9	(133.7)	109.5
Risk management assets and liabilities	(83.5)	58.6	(93.2)
Materials, supplies and fuel stocks	(51.5)	(11.7)	(90.9)
Other current assets	19.3	130.3	(20.5)
Accounts payable	204.1	188.4	(226.7)
Other current liabilities	107.4	53.9	(20.3)
Other	(10.3)	(44.4)	(34.4)
Net cash provided by operating activities	1,080.1	1,020.0	573.3
Cash Flows From Investing Activities			
Investments in property, plant and equipment	(658.0)	(831.9)	(1,302.5)
Acquisitions, net of cash acquired	(546.6)	(221.4)	(382.7)
Contributions to nuclear decommissioning trust funds	(13.2)	(17.6)	(22.0)
Sale of investments and other assets	148.8	838.0	287.1
Other investments	(113.6)	(86.9)	(52.6)
Net cash used in investing activities	(1,182.6)	(319.8)	(1,472.7)
Cash Flows From Financing Activities			
Net (maturity) issuance of short-term borrowings	(0.9)	(964.5)	731.4
Proceeds from issuance of			
Long-term debt	983.3	2,529.3	1,175.2
Common stock	95.4	28.5	504.4
Repayment of long-term debt	(707.5)	(1,627.7)	(1,510.2)
Common stock dividends paid	(169.2)	(137.8)	(120.7)
Other	7.7	14.6	9.0
Net cash provided by (used in) financing activities	208.8	(157.6)	789.1
Net Increase (Decrease) in Cash and Cash Equivalents	106.3	542.6	(110.3)
Cash and Cash Equivalents at Beginning of Year	615.0	72.4	182.7
Cash and Cash Equivalents at End of Year	$ 721.3	$ 615.0	$ 72.4
Other Cash Flow Information:			
Cash paid during the year for:			
Interest (net of amounts capitalized)	$ 339.4	$ 230.5	$ 238.3
Income taxes	$ 34.0	$ 157.8	$ 101.5

Non-Cash Transaction:

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

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

CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDERS' EQUITY AND COMPREHENSIVE INCOME

Constellation Energy Group, Inc. and Subsidiaries

Year Ended December 31, 2003, 2002, and 2001	Common Stock Shares	Common Stock Amount	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Amount
	(Dollar amounts in millions, number of shares in thousands)				
Balance at December 31, 2000	150,532	$1,538.7	$1,592.3	$ 43.0	$3,174.0
Comprehensive Income					
Net income			90.9		90.9
Other comprehensive income (OCI)					
Cumulative effect of change in accounting principle, net of taxes of $22.6				(35.5)	(35.5)
Reclassification of net gain on sales of securities from OCI to net income, net of taxes of $15.7				(24.0)	(24.0)
Net unrealized gain on securities, net of taxes of $87.5				148.5	148.5
Net unrealized gain on hedging instruments, net of taxes of $65.6				102.6	102.6
Minimum pension liability, net of taxes of $29.3				(44.7)	(44.7)
Total Comprehensive Income			90.9	146.9	237.8
Common stock dividend declared ($0.48 per share)			(77.1)		(77.1)
Common stock issued	13,176	504.4			504.4
Other		(0.9)	5.4		4.5
Balance at December 31, 2001	163,708	2,042.2	1,611.5	189.9	3,843.6
Comprehensive Income					
Net income			525.6		525.6
Other comprehensive income					
Reclassification of net gain on sales of securities from OCI to net income, net of taxes of $87.7				(152.8)	(152.8)
Reclassification of net gains on hedging instruments from OCI to net income, net of taxes of $10.9				(17.8)	(17.8)
Net unrealized loss on securities, net of taxes of $28.6				(43.2)	(43.2)
Net unrealized loss on hedging instruments, net of taxes of $31.7				(52.2)	(52.2)
Minimum pension liability, net of taxes of $77.2				(118.1)	(118.1)
Total Comprehensive Income			525.6	(384.1)	141.5
Common stock dividend declared ($0.96 per share)			(157.6)		(157.6)
Common stock issued	1,135	28.5			28.5
Other		8.2	(1.9)		6.3
Balance at December 31, 2002	164,843	2,078.9	1,977.6	(194.2)	3,862.3
Comprehensive Income					
Net income			277.3		277.3
Other comprehensive income					
Reclassification of net gain on sales of securities from OCI to net income, net of taxes of $0.2				(0.4)	(0.4)
Reclassification of net gains on hedging instruments from OCI to net income, net of taxes of $10.7				(16.4)	(16.4)
Net unrealized gain on securities, net of taxes of $24.4				37.3	37.3
Net unrealized gain on hedging instruments, net of taxes of $15.8				39.9	39.9
Minimum pension liability, net of taxes of $8.2				12.6	12.6
Total Comprehensive Income			277.3	73.0	350.3
Common stock dividend declared ($1.04 per share)			(172.8)		(172.8)
Common stock issued	2,976	100.9			100.9
Other			(0.2)		(0.2)
Balance at December 31, 2003	167,819	$2,179.8	$2,081.9	$(121.2)	$4,140.5

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

CONSOLIDATED STATEMENTS OF CAPITALIZATION

Constellation Energy Group, Inc. and Subsidiaries

At December 31,	2003	2002
	(In millions)	
Long-Term Debt		
Long-term debt of Constellation Energy		
7⅞% Notes, due April 1, 2005	$ 300.0	$ 300.0
6.35% Fixed Rate Notes, due April 1, 2007	600.0	600.0
6.125% Fixed Rate Notes, due September 1, 2009	500.0	500.0
7.00% Fixed Rate Notes, due April 1, 2012	700.0	700.0
4.55% Fixed Rate Notes, due June 15, 2015	550.0	—
7.60% Fixed Rate Notes, due April 1, 2032	700.0	700.0
Total long-term debt of Constellation Energy	3,350.0	2,800.0
Long-term debt of nonregulated businesses		
Tax-exempt debt transferred from BGE effective July 1, 2000		
Pollution control loan, due July 1, 2011	36.0	36.0
Port facilities loan, due June 1, 2013	48.0	48.0
Adjustable rate pollution control loan, due July 1, 2014	20.0	20.0
5.55% Pollution control revenue refunding loan, due July 15, 2014	47.0	47.0
Economic development loan, due December 1, 2018	35.0	35.0
6.00% Pollution control revenue refunding loan, due April 1, 2024	75.0	75.0
Floating rate pollution control loan, due June 1, 2027	8.8	8.8
District Cooling facilities loan, due December 1, 2031	25.0	25.0
Loans under revolving credit agreements	46.3	51.7
Geothermal facilities loan, due September 30, 2011	45.3	—
4.25% Mortgage note, due March 15, 2009	2.8	3.3
Total long-term debt of nonregulated businesses	389.2	349.8
First Refunding Mortgage Bonds of BGE		
6½% Series, due February 15, 2003	—	124.8
6⅛% Series, due July 1, 2003	—	124.9
5½% Series, due April 15, 2004	125.0	125.0
Remarketed floating rate series, due September 1, 2006	104.1	111.5
7½% Series, due January 15, 2007	122.5	123.5
6⅝% Series, due March 15, 2008	124.5	124.9
7½% Series, due March 1, 2023	—	98.1
7½% Series, due April 15, 2023	—	72.2
Total First Refunding Mortgage Bonds of BGE	476.1	904.9
Other long-term debt of BGE		
5.25% Notes, due December 15, 2006	300.0	300.0
5.20% Notes, due June 15, 2033	200.0	—
Medium-term notes, Series B	12.1	12.1
Medium-term notes, Series C	—	25.5
Medium-term notes, Series D	68.0	68.0
Medium-term notes, Series E	199.5	199.5
Medium-term notes, Series G	140.0	140.0
Total other long-term debt of BGE	919.6	745.1
6.20% deferrable interest subordinated debentures due October 15, 2043 to BGE wholly owned BGE Capital Trust II relating to trust preferred securities	257.7	—
BGE obligated mandatorily redeemable trust preferred securities of subsidiary trust holding solely 7.16% deferrable interest subordinated debentures due June 30, 2038	—	250.0
Unamortized discount and premium	(10.2)	(9.7)
Current portion of long-term debt	(343.2)	(426.2)
Total long-term debt	$5,039.2	$4,613.9

See Notes to Consolidated Financial Statements.

continued on next page

CONSOLIDATED STATEMENTS OF CAPITALIZATION

Constellation Energy Group, Inc. and Subsidiaries

At December 31,	2003	2002
	(In millions)	
Minority Interests	$ 113.4	$ 105.3
BGE Preference Stock		
Cumulative preference stock not subject to mandatory redemption, 6,500,000 shares authorized		
7.125%, 1993 Series, 400,000 shares outstanding, callable at $103.21 per share until June 30, 2004, and at lesser amounts thereafter	40.0	40.0
6.97%, 1993 Series, 500,000 shares outstanding, callable at $103.14 per share until September 30, 2004, and at lesser amounts thereafter	50.0	50.0
6.70%, 1993 Series, 400,000 shares outstanding, callable at $103.34 per share until December 31, 2004, and at lesser amounts thereafter	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; 167,819,338 and 164,842,708 shares issued and outstanding at December 31, 2003 and 2002, respectively. (At December 31, 2003, 18,000,000 shares were reserved for the long-term incentive plans, 10,751,569 shares were reserved for the Shareholder Investment Plan, 520,000 shares were reserved for the continuous offering programs, and 945,018 shares were reserved for the employee savings plan.)	2,179.8	2,078.9
Retained earnings	2,081.9	1,977.6
Accumulated other comprehensive loss	(121.2)	(194.2)
Total common shareholders' equity	4,140.5	3,862.3
Total Capitalization	$9,483.1	$8,771.5

See Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF INCOME

Baltimore Gas and Electric Company and Subsidiaries

Year Ended December 31,	2003	2002	2001
		(In millions)	
Revenues			
Electric revenues	$1,921.6	$1,966.0	$2,040.0
Gas revenues	726.0	581.3	680.7
Total revenues	2,647.6	2,547.3	2,720.7
Expenses			
Operating Expenses			
Electric fuel and purchased energy	1,023.5	1,080.7	1,192.8
Gas purchased for resale	445.8	316.7	401.3
Operations and maintenance	395.4	355.3	363.0
Workforce reduction costs	0.7	35.3	57.0
Depreciation and amortization	228.3	221.6	221.0
Taxes other than income taxes	168.9	171.4	173.8
Total expenses	2,262.6	2,181.0	2,408.9
Income from Operations	385.0	366.3	311.8
Other (Expense) Income	(5.4)	10.7	0.4
Fixed Charges			
Interest expense	112.8	142.1	156.2
Allowance for borrowed funds used during construction	(1.6)	(1.5)	(1.6)
Total fixed charges	111.2	140.6	154.6
Income Before Income Taxes	268.4	236.4	157.6
Income Taxes			
Current	48.5	67.4	62.4
Deferred	58.5	28.0	0.2
Investment tax credit adjustments	(1.8)	(2.1)	(2.3)
Total income taxes	105.2	93.3	60.3
Net Income	163.2	143.1	97.3
Preference Stock Dividends	13.2	13.2	13.2
Earnings Applicable to Common Stock	$ 150.0	$ 129.9	$ 84.1

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Baltimore Gas and Electric Company and Subsidiaries

Year Ended December 31,	2003	2002	2001
		(In millions)	
Net Income	$ 150.0	$ 129.9	$ 84.1
Other comprehensive income			
Unrealized gain on hedging instruments, net of taxes of $0.4	0.8	—	—
Comprehensive Income	$ 150.8	$ 129.9	$ 84.1

See Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

Baltimore Gas and Electric Company and Subsidiaries

At December 31,	2003	2002
	(In millions)	
Assets		
Current Assets		
Cash and cash equivalents	$ 11.0	$ 10.2
Accounts receivable (net of allowance for uncollectibles of $10.7 and $11.5, respectively)	354.8	357.5
Investment in cash pool, affiliated company	230.2	338.1
Accounts receivable, affiliated companies	4.5	131.2
Fuel stocks	62.8	40.6
Materials and supplies	29.9	31.8
Prepaid taxes other than income taxes	42.8	42.0
Other	9.9	10.3
Total current assets	745.9	961.7
Investments and Other Assets		
Receivable, affiliated company	131.6	63.3
Other	90.4	85.9
Total other assets	222.0	149.2
Utility Plant		
Plant in service		
Electric	3,599.3	3,422.3
Gas	1,064.7	1,041.0
Common	467.7	489.1
Total plant in service	5,131.7	4,952.4
Accumulated depreciation	(1,807.7)	(1,743.0)
Net plant in service	3,324.0	3,209.4
Construction work in progress	130.5	118.3
Plant held for future use	4.5	4.5
Net utility plant	3,459.0	3,332.2
Deferred Charges		
Regulatory assets (net)	229.5	297.3
Other	50.2	39.5
Total deferred charges	279.7	336.8
Total Assets	$4,706.6	$4,779.9

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

CONSOLIDATED BALANCE SHEETS

Baltimore Gas and Electric Company and Subsidiaries

At December 31,	2003	2002
	(In millions)	
Liabilities and Equity		
Current Liabilities		
Current portion of long-term debt	$ 330.6	$ 420.7
Accounts payable	111.2	103.2
Accounts payable, affiliated companies	151.7	85.6
Customer deposits	59.7	54.2
Accrued taxes	33.0	9.0
Accrued interest	22.3	31.4
Other	43.3	49.7
Total current liabilities	751.8	753.8
Deferred Credits and Other Liabilities		
Deferred income taxes	585.8	528.9
Postretirement and postemployment benefits	279.2	278.0
Deferred investment tax credits	18.7	20.5
Decommissioning of federal uranium enrichment facilities	10.0	14.6
Other	20.8	13.9
Total deferred credits and other liabilities	914.5	855.9
Long-term Debt		
First refunding mortgage bonds of BGE	476.1	904.9
Other long-term debt of BGE	919.6	745.1
6.20% deferrable interest subordinated debentures due October 15, 2043 to wholly owned BGE Capital Trust II relating to trust preferred securities	257.7	—
Company obligated mandatorily redeemable trust preferred securities of subsidiary trust holding solely 7.16% deferrable interest subordinated debentures due June 30, 2038	—	250.0
Long-term debt of nonregulated businesses	25.0	25.0
Unamortized discount and premium	(4.1)	(5.2)
Current portion of long-term debt	(330.6)	(420.7)
Total long-term debt	1,343.7	1,499.1
Minority Interest	18.9	19.4
Preference Stock Not Subject to Mandatory Redemption	190.0	190.0
Common Shareholder's Equity		
Common stock	912.2	912.2
Retained earnings	574.7	549.5
Accumulated other comprehensive income	0.8	—
Total common shareholder's equity	1,487.7	1,461.7
Commitments, Guarantees, and Contingencies (see Note 12)		
Total Liabilities and Equity	$ 4,706.6	$ 4,779.9

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

CONSOLIDATED STATEMENTS OF CASH FLOWS

Baltimore Gas and Electric Company and Subsidiaries

Year Ended December 31,	2003	2002	2001
		(In millions)	
Cash Flows From Operating Activities			
Net income	$ 163.2	$ 143.1	$ 97.3
Adjustments to reconcile to net cash provided by operating activities			
Depreciation and amortization	231.0	224.4	223.3
Deferred income taxes	58.5	28.0	0.2
Investment tax credit adjustments	(1.8)	(2.1)	(2.3)
Deferred fuel costs	(10.1)	23.9	37.6
Pension and postemployment benefits	(56.2)	(40.7)	14.7
Allowance for equity funds used during construction	(3.0)	(2.8)	(3.0)
Workforce reduction costs	0.7	35.3	57.0
Changes in			
Accounts receivable	2.7	(62.3)	117.8
Receivables, affiliated companies	126.7	58.9	(183.5)
Materials, supplies and fuel stocks	(20.3)	13.0	(14.0)
Other current assets	(0.4)	27.8	(30.5)
Accounts payable	8.0	39.6	(55.7)
Accounts payable, affiliated companies	66.1	(7.0)	(10.9)
Other current liabilities	14.0	(11.2)	(7.7)
Other	11.1	26.5	131.5
Net cash provided by operating activities	590.2	494.4	371.8
Cash Flows From Investing Activities			
Utility construction expenditures (excluding equity portion of AFC)	(291.3)	(216.7)	(236.4)
Investment in cash pool at parent	107.9	101.0	(441.1)
Other	1.8	(17.0)	(20.9)
Net cash used in investing activities	(181.6)	(132.7)	(698.4)
Cash Flows From Financing Activities			
Net maturity of short-term borrowings	—	—	(32.1)
Proceeds from issuance of long-term debt	439.4	—	532.1
Repayment of long-term debt	(710.4)	(575.5)	(394.1)
Preference stock dividends paid	(13.2)	(13.2)	(13.2)
Distribution (to) from parent	(124.8)	200.0	250.0
Other	1.2	(0.2)	—
Net cash (used in) provided by financing activities	(407.8)	(388.9)	342.7
Net Increase (Decrease) in Cash and Cash Equivalents	0.8	(27.2)	16.1
Cash and Cash Equivalents at Beginning of Year	10.2	37.4	21.3
Cash and Cash Equivalents at End of Year	$ 11.0	$ 10.2	$ 37.4
Other Cash Flow Information:			
Cash paid during the year for:			
Interest (net of amounts capitalized)	$ 120.6	$ 147.5	$ 162.0
Income taxes	$ 24.7	$ 36.6	$ 102.8

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

1 Significant Accounting Policies

Nature of Our Business

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

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

Consolidation Policy

We use three different accounting methods to report our investments in our subsidiaries or other companies: consolidation, the equity method, and the cost method. We discuss the implications of the Financial Accounting Standards Board (FASB) Interpretation No. 46R, *Consolidation of Variable Interest Entities* (FIN 46R) on our consolidation policy later in this Note.

Consolidation

We use consolidation when we own a majority of the voting stock of the subsidiary, except for special purpose entities, for which consolidation is determined in accordance with the provisions of FIN 46R effective December 31, 2003. Consolidation means the accounts of our subsidiaries are combined with our accounts. We eliminate intercompany balances and transactions when we consolidate these accounts.

The Equity Method

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

- our interest in the entity as an investment in our Consolidated Balance Sheets, and
- our percentage share of the earnings from the entity in our Consolidated Statements of Income.

The only time we do not use this method is if we can exercise control over the operations and policies of the company. If we have control, accounting rules require us to use consolidation.

The Cost Method

We usually use the cost method if we hold less than a 20% voting interest in an investment. Under the cost method, we report our investment at cost in our Consolidated Balance Sheets. The only time we do not use this method is when we can exercise significant influence over the operations and policies of the company. If we have significant influence, accounting rules require us to use the equity method.

Regulation of Utility Business

The Maryland Public Service Commission (Maryland PSC) and the Federal Energy Regulatory Commission (FERC) provide the final determination of the rates we charge our customers for our regulated businesses. Generally, we use the same accounting policies and practices used by nonregulated companies for financial reporting under accounting principles generally accepted in the United States of America. However, sometimes the Maryland PSC or the FERC orders an accounting treatment different from that used by nonregulated companies to determine the rates we charge our customers.

When this happens, we must defer (include as an asset or liability in our Consolidated Balance Sheets and exclude from our Consolidated Statements of Income) certain utility expenses and income as regulatory assets and liabilities. We have recorded these regulatory assets and liabilities in our Consolidated Balance Sheets in accordance with Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulation.*

We summarize and discuss our regulatory assets and liabilities further in *Note 6*.

Use of Accounting Estimates

Management makes estimates and assumptions when preparing financial statements under accounting principles generally accepted in the United States of America. These estimates and assumptions affect various matters, including:

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

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

Reclassifications

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

Revenues

Nonregulated Businesses

We record revenues from the sale of energy, energy-related products, and energy services under the accrual method of accounting in the period when we deliver energy commodities or products, render services, or settle contracts. We use accrual accounting for our merchant energy and other nonregulated business transactions, including the generation or purchase and sale of electricity and gas as part of our physical delivery activities and for power and gas sales contracts that are not subject to mark-to-market accounting. Sales contracts that are eligible for accrual accounting include non-derivative transactions and derivatives that qualify for and are designated as normal purchases and normal sales of commodities that will be physically delivered. We record accrual revenues, including settlements with independent system operators, on a gross basis because we are a principal to the transaction and otherwise meet the requirements of Emerging Issues Task Force (EITF) 03-11, *Reporting Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133, Accounting for Derivative Instruments and Hedging Activities, and Not Held for Trading Purposes*, and EITF 99-19, *Reporting Revenue Gross as a Principal versus Net as an Agent.*

We record revenues using the mark-to-market method of accounting for derivative contracts for which we are not permitted to use accrual accounting or hedge accounting. We discuss our use of hedge accounting in the *Derivatives and Hedging Activities* section later in this Note. These mark-to-market activities include derivative contracts for energy and other energy-related commodities. Under the mark-to-market method of accounting, we record the fair value of these derivatives as mark-to-market energy assets and liabilities at the time of contract execution. We record the changes in mark-to-market energy assets and liabilities on a net basis in "Nonregulated revenues" in our Consolidated Statements of Income. Mark-to-market revenues include:

- gains or losses on new transactions at origination to the extent permitted by applicable accounting rules,
- unrealized gains and losses from changes in the fair value of open contracts,
- net gains and losses from realized transactions, and
- changes in reserves.

We record reserves to reflect uncertainties associated with certain estimates inherent in the determination of the fair value of mark-to-market energy assets and liabilities. To the extent possible, we utilize market-based data together with quantitative methods for both measuring the uncertainties for which we record reserves and determining the level of such reserves and changes in those levels.

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

- Close-out reserve—this reserve represents the estimated cost to close out or sell to a third-party open mark-to-market positions. This reserve has the effect of valuing "long" positions at the bid price and "short" positions at the offer price. We compute this reserve based on our estimate of the bid/offer spread for each commodity and option price and the absolute quantity of our net open positions for each year. To the extent that we are not able to obtain market information for similar contracts, the close-out reserve is equivalent to the initial contract margin, thereby recording no gain or loss at inception. The level of total close-out reserves increases as we have larger unhedged positions, bid-offer spreads increase, or market information is not available, and it decreases as we reduce our unhedged positions, bid-offer spreads decrease, or market information becomes available.
- Credit-spread adjustment—for risk management purposes we compute the value of our mark-to-market energy assets and liabilities using a risk-free discount rate. In order to compute fair value for financial reporting purposes, we adjust the value of our mark-to-market energy assets to reflect the credit-worthiness of each counterparty based upon published credit ratings, where available, or equivalent internal credit ratings and associated default probability percentages. We compute this reserve by applying the appropriate default probability percentage to our outstanding credit exposure, net of collateral, for each counterparty.

At December 31, 2003, mark-to-market energy assets and liabilities consist of derivative contracts. At December 31, 2002, mark-to-market energy assets and liabilities consisted of a combination of energy and energy-related derivative and non-derivative contracts. While some of these contracts represent commodities or instruments for which prices are available from external sources, other commodities and certain contracts are not actively traded and are valued using modeling techniques to determine expected future market prices, contract quantities, or both. The market prices and quantities used to determine fair value reflect management's best estimate considering various factors, including closing exchange and over-the-counter quotations, time value, and volatility factors. However, future market prices and actual quantities will vary from those used in recording mark-to-market energy assets and liabilities, and it is possible that such variations could be material.

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

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

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

Regulated Utility

We record utility revenues when we provide service to customers.

Fuel and Purchased Energy Costs

We incur costs for:

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

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

Fuel Used to Generate Electricity and Purchases of Electricity From Others

We assemble a variety of power supply resources, including baseload, intermediate, and peaking plants that we own, as well as a variety of power supply contracts that may have similar characteristics, in order to enable us to meet our customers' energy requirements, which vary on an hourly basis. We purchase power when our load-serving requirements exceed the amount of power available from our supply resources or when it is more economic to do so than to operate our power plants.

The amount of power purchased depends on a number of factors, including the capacity and availability of our power plants, the level of customer demand, and the relative economics of generating power versus purchasing power from the spot market. BGE purchases from our wholesale marketing and risk management operation 100% of the energy and capacity required to meet its standard offer service obligations through June 30, 2004 and 100% of the energy and capacity required to meet its residential standard offer service obligations through June 30, 2006.

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

	2003	2002	2001
		(In millions)	
Fuel and Purchased Energy	**$5,662.4**	$1,167.9	$479.6

Natural Gas

BGE charges its gas customers for the natural gas they purchase from BGE using "gas cost adjustment clauses" set by the Maryland PSC. Under these clauses, BGE defers the difference between certain of its actual costs of gas and what it collects from customers under the fuel rate in a given period for those types of costs. BGE either bills or refunds its customers the difference in the future. 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, BGE's actual cost of gas is compared to a market index (a measure of the market price of gas in a given period). The difference between BGE's actual cost and the market index is shared equally between shareholders and customers. Effective November 2001, the Maryland PSC approved an order that modifies certain provisions of the market-based rates incentive mechanism. These provisions require that BGE secure fixed-price contracts for at least 10%, but not more than 20%, of forecasted system supply requirements for the November through March period. These fixed price contracts are not subject to sharing under the market-based rates incentive mechanism.

Derivatives and Hedging Activities

We are exposed to market risk, including changes in interest rates and the impact of market fluctuations in the price and transportation costs of electricity, natural gas, and other commodities as discussed further in *Note 13*. We use both derivative and non-derivative contracts to manage these risks. SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended, requires that we recognize all derivatives not qualifying for accrual accounting under the normal purchase and normal sale exception at fair value. We record derivatives that are designated as hedges in "Risk management assets or liabilities" and derivatives not designated as hedges in "Mark-to-market energy assets or liabilities" in our Consolidated Balance Sheets.

We record changes in the value of derivatives that are not designated as cash-flow hedges in earnings during the period of change. We record changes in the value of derivatives designated as cash-flow hedges that are effective in offsetting the variability in cash flows of forecasted transactions in other comprehensive income until the forecasted transactions occur. At the time the forecasted transactions occur, we reclassify the amounts recorded in other comprehensive income into earnings. We record the ineffective portion of changes in the fair value of derivatives used as cash-flow hedges immediately in earnings.

We summarize our hedging activities under SFAS No. 133 and the income statement classification of amounts reclassified from "Accumulated other comprehensive income" as follows:

Risk	Derivative	Income Statement Classification
Interest rate risk associated with new debt issuances	Interest rate swaps	Interest expense
Nonregulated energy sales	Futures and forward contracts	Nonregulated revenues
Nonregulated fuel and energy purchases	Futures and forward contracts	Operating expenses
Nonregulated gas purchases for resale	Futures contracts and price and basis swaps	Operating expenses
Regulated gas purchases for resale	Price and basis swaps	Operating expenses

When we adopted SFAS No. 133, we recorded the following at January 1, 2001:

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

The cumulative effect adjustment recorded in earnings represents the fair value as of January 1, 2001 of a warrant for 705,900 shares of common stock of Orion. The warrant had an exercise price of $10 per share and was received in conjunction with our investment in Orion.

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

Credit Risk

Credit risk is the loss that may result from counterparty non-performance. We are exposed to credit risk, primarily through our merchant energy business. We use credit policies to manage our credit risk, including utilizing an established credit approval process, monitoring counterparty limits, employing credit mitigation measures such as margin, collateral or prepayment arrangements, and using master netting agreements. We measure credit risk as the replacement cost for open energy commodity and derivative positions (both mark-to-market and accrual) plus amounts owed from counterparties for settled transactions. The replacement cost of open positions represents unrealized gains, net of any unrealized losses, where we have a legally enforceable right of setoff.

Electric and gas utilities, cooperatives, and energy marketers comprise the majority of counterparties underlying our assets from our wholesale marketing and risk management activities. We held cash collateral from these counterparties totaling $121.9 million as of December 31, 2003 and $50.1 million as of December 31, 2002. These amounts are included in "Customer deposits and collateral" in our Consolidated Balance Sheets.

Taxes

We summarize our income taxes in *Note 10*. Our subsidiary income taxes are computed on a separate return basis. As you read this section, it may be helpful to refer to *Note 10*.

Income Tax Expense

We have two categories of income taxes—current and deferred. We describe each of these below:

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

Tax Credits

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

We have certain investments in facilities that manufacture solid synthetic fuel produced from coal as defined under Section 29 of the Internal Revenue Code for which we claim tax credits on our Federal income tax return. We recognize the tax benefit of these credits in our Consolidated Statements of Income when we believe it is highly probable that the credits will be sustained.

Deferred Income Tax Assets and Liabilities

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

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

State and Local Taxes

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

BGE also pays Maryland public service company franchise tax on distribution, and delivery of electricity and natural gas. We include the franchise tax in "Taxes other than income taxes" in our Consolidated Statements of Income.

Earnings Per Share

Basic earnings per common share (EPS) is computed by dividing earnings applicable to common stock by the weighted-average number of common shares outstanding for the year. Diluted EPS reflects the potential dilution of common stock equivalent shares that could occur if securities or other contracts to issue common stock were exercised or converted into common stock. For 2003, our dilutive common stock equivalent shares were 0.5 million consisting of stock options. Stock options to purchase approximately 1.2 million shares in 2003, 4.1 million shares in 2002, and approximately 0.1 million shares in 2001 were not dilutive and were excluded from the computation of diluted EPS for these respective years.

Stock-Based Compensation

Under our long-term incentive plans, we granted stock options, performance and service-based restricted stock, and equity to officers, key employees, and members of the Board of Directors. We discuss this in more detail in *Note 14*.

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

Our stock options are granted with an exercise price not less than the market value of the common stock at the date of grant. Accordingly, no compensation expense is recorded for these awards. However, when we grant options subject to a contingency, we recognize compensation expense when options granted have an exercise price less than the market value of the underlying common stock on the date the contingency is satisfied. We amortize compensation expense for restricted stock over the performance/service period, which is typically a one to five year period.

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

Year Ended December 31,	2003	2002	2001
	(In millions, except per share amounts)		
Net income, as reported	$277.3	$525.6	$90.9
Add: Stock-based compensation determined under intrinsic value method and included in reported net income, net of related tax effects	12.0	6.4	(6.1)
Deduct: Stock-based compensation expense determined under fair value based method for all awards, net of related tax effects	(20.7)	(17.1)	(0.9)
Pro-forma net income	$268.6	$514.9	$83.9
Earnings per share:			
Basic—as reported	$ 1.67	$ 3.20	$ .57
Basic—pro forma	$ 1.62	$ 3.14	$ .52
Diluted—as reported	$ 1.66	$ 3.20	$ .57
Diluted—pro forma	$ 1.61	$ 3.13	$ .52

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

- in 2003, $12.0 million after-tax, or $18.6 million pre-tax comprised of $1.8 million of pre-tax expense for certain stock options, $16.4 million for restricted stock, and $0.4 million for equity grants,
- in 2002, $6.4 million after-tax, or $10.1 million pre-tax comprised of $3.0 million of pre-tax expense for certain stock options, $6.6 million for restricted stock, and $0.5 million for equity grants, and
- in 2001, a $(6.1) million after-tax, or $(10.1) million pre-tax reversal of expense for restricted stock as a result of non-attainment of performance criteria.

Cash and Cash Equivalents

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

Inventory

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

Real Estate Projects and Investments

In *Note 4*, we summarize the real estate projects and investments that are in our Consolidated Balance Sheets. At December 31, 2003, the projects and investments primarily consist of approximately 220 acres of land holdings in various stages of development located at 4 sites in the central Maryland region, including an operating waste water treatment plant located in Anne Arundel County, Maryland. The costs incurred to develop properties are included as part of the cost of the properties.

Financial Investments and Trading Securities
In *Note 4*, we summarize the financial investments that are in our Consolidated Balance Sheets.

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

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

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

In addition, our other nonregulated businesses classified some of their investments in marketable equity securities as available-for-sale securities.

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

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

We determine if long-lived assets are impaired by comparing their undiscounted expected future cash flows to their carrying amount in our accounting records. We would record an impairment loss if the undiscounted expected future cash flows from an asset were less than the carrying amount of the asset. We are also required to evaluate our equity-method and cost-method investments (for example, in partnerships that own power projects) for impairment. APB No. 18, *The Equity Method of Accounting for Investments in Common Stock*, provides the accounting for these investments. The standard for determining whether an impairment must be recorded under APB No. 18 is whether the investment has experienced a loss in value that is considered an "other than a temporary" decline in value.

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

Intangible Assets
Goodwill is the excess of the purchase price of an acquisition over the fair value of the net assets acquired. We do not amortize goodwill under the provisions of SFAS No. 142, *Goodwill and Other Intangible Assets*. SFAS No. 142 requires the evaluation of goodwill for impairment at least annually or more frequently if events and circumstances indicate that the asset might be impaired. SFAS No. 142 also requires the amortization of intangible assets with finite lives. We discuss the changes in our intangible assets in more detail in *Note 5*.

Property, Plant and Equipment, Depreciation, Amortization, Accretion of Asset Retirement Obligations, and Decommissioning
We report our property, plant and equipment at its original cost, unless impaired under the provisions of SFAS No. 144.

Our original costs include:

- material and labor,
- contractor costs, and
- construction overhead costs, financing costs, and costs for asset retirement obligations (where applicable).

We own an undivided interest in the Keystone and Conemaugh electric generating plants in Western Pennsylvania, as well as in the transmission line that transports the plants' output to the joint owners' service territories. Our ownership interests in these plants are 20.99% in Keystone and 10.56% in Conemaugh. These ownership interests represented a net investment of $189 million at December 31, 2003 and $168 million at December 31, 2002. Each owner is responsible for financing its proportionate share of the plants' working funds. Working funds are used for operating expenses and capital expenditures. Operating expenses related to these plants are included in "Operating expenses" in our Consolidated Statements of Income. Capital costs related to these plants are included in "Nonregulated generation property, plant and equipment" in our Consolidated Balance Sheets.

The "Nonregulated generation property, plant and equipment" in our Consolidated Balance Sheets includes nonregulated generation construction work in progress of $184.4 million at December 31, 2003 and $237.2 million at December 31, 2002.

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

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

Depreciation Expense

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

- the composite, straight-line rates method, approved by the Maryland PSC, applied to the average investment, adjusted for anticipated costs of removal less salvage, in classes of depreciable property based on an average rate of approximately 3.0% per year for our regulated utility business,
- the composite, straight-line rates applied to the average investment, in classes of depreciable property based on an average rate of approximately 2.5% per year for the generating assets transferred from BGE to our merchant energy business, or
- the modified units of production method (greater of straight-line method or units of production method) for other generating assets.

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

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

Amortization Expense

Amortization is an accounting process of reducing an amount in our Consolidated Balance Sheets evenly over a period of time that approximates the useful life of the related item. When we reduce amounts in our Consolidated Balance Sheets, we increase amortization expense in our Consolidated Statements of Income.

We also amortize the fair value of assets and liabilities associated with acquired contracts based on the expected cash flows provided by the contracts. We recognize the amortization of these contracts as either "Nonregulated revenues" or "Operating expenses" depending on whether the contract acquired was a sales contract or a purchased energy contract.

Accretion Expense

In 2001, the FASB issued SFAS No. 143, *Accounting for Asset Retirement Obligations.* SFAS No. 143 provides the accounting requirements for recognizing an estimated liability for legal obligations associated with the retirement of tangible long-lived assets. We measure the liability at fair value when incurred and capitalize a corresponding amount as part of the book value of the related long-lived assets. The increase in the capitalized cost is included in determining depreciation expense over the estimated useful life of these assets. Since the fair value of the asset retirement obligations is determined using a present value approach, accretion of the liability due to the passage of time is recognized each period to "Accretion of asset retirement obligations" in our Consolidated Statements of Income until the settlement of the liability. We record a gain or loss when the liability is settled after retirement.

The change in our "Asset retirement obligations" liability during 2003 was as follows:

	(In millions)
Liability at January 1, 2003	$570.6
Liabilities incurred	3.3
Liabilities settled	(20.7)
Accretion expense	42.7
Revisions to cash flows	—
Liability at December 31, 2003	$595.9

The pro-forma asset retirement obligation we would have recognized as of January 1, 2002, had we implemented SFAS No. 143 as of that date, was approximately $530 million based on the information, assumptions, and interest rates as of January 1, 2003 used to determine the $570.6 million liability recognized upon the adoption of SFAS No. 143.

We discuss SFAS No. 143 in more detail in the *Accounting Standards Adopted* section later in this Note.

Nuclear Fuel

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

Nuclear Decommissioning
Effective January 1, 2003 we began to record decommissioning expense for Calvert Cliffs Nuclear Power Plant (Calvert Cliffs) in accordance with SFAS No. 143 *Accounting for Asset Retirement Obligations* (SFAS 143). Prior to that date, we accounted for decommissioning expense using the internal sinking fund method. The "Asset retirement obligations" liability associated with the decommissioning of Calvert Cliffs was $265.5 million at December 31, 2003 (under SFAS No. 143) and $333.7 million at December 31, 2002 (under the prior sinking fund methodology).

Our contributions to the nuclear decommissioning trust funds for Calvert Cliffs were $13.2 million for 2003, $17.6 million for 2002 and $22.0 million for 2001.

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

We began to record decommissioning expense for Nine Mile Point Nuclear Station (Nine Mile Point) in accordance with SFAS No. 143 on January 1, 2003. Prior to that date we accounted for decommissioning expense using the discounted cash flow method. The "Asset retirement obligations" liability associated with the decommissioning was $326.2 million at December 31, 2003 (under SFAS No. 143) and $242.1 million at December 31, 2002 (under the discounted cash flow methodology).

We determined that the decommissioning trust funds established for Nine Mile Point are adequately funded to cover the future costs to decommission the plant and as such, no contributions were made to the trust funds during the years ended December 31, 2003, 2002, and 2001.

In accordance with Nuclear Regulatory Commission (NRC) regulations, we maintain external decommissioning trusts to fund the costs expected to be incurred to decommission Calvert Cliffs and Nine Mile Point. The NRC requires utilities to provide financial assurance that they will accumulate sufficient funds to pay for the cost of nuclear decommissioning. The assets in the trusts are reported in "Nuclear decommissioning trust funds" in our Consolidated Balance Sheets. These amounts are legally restricted for funding the costs of decommissioning. We classify the investments in the nuclear decommissioning trust funds as available-for-sale securities, and we report these investments at fair value in our Consolidated Balance Sheets as previously discussed in this Note. Investments by nuclear decommissioning trust funds are guided by the "prudent man" investment principle. The funds are prohibited from investing in Constellation Energy or its affiliates and any other entity owning a nuclear power plant.

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

Capitalized Interest and Allowance for Funds Used During Construction
Capitalized Interest
With the deregulation of electric generation, we ceased accruing AFC (discussed below) for electric generation-related construction projects.

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

Allowance for Funds Used During Construction (AFC)
BGE finances its construction projects with borrowed funds and equity funds. BGE is allowed by the Maryland PSC to record the costs of these funds as part of the cost of construction projects in its Consolidated Balance Sheets. BGE does this through the AFC, which it calculates using rates authorized by the Maryland PSC. BGE bills its customers for the AFC plus a return after the utility property is placed in service.

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

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

When BGE incurs gains or losses on debt that it retires prior to maturity, it amortizes those gains or losses over the remaining original life of the debt.

Accounting Standards Issued
FIN 46/FIN 46R
In January 2003, the FASB issued Interpretation No. (FIN) 46, *Consolidation of Variable Interest Entities*. Subsequently, in December 2003, the FASB issued a revised Interpretation (FIN 46R) to address certain implementation issues and technical corrections. FIN 46R replaces in its entirety the previously issued interpretation.

FIN 46R establishes conditions under which an entity must be consolidated based upon variable interests rather than voting interests. Variable interests are ownership interests or contractual relationships that enable the holder to share in the financial risks and rewards resulting from the activities of a Variable Interest Entity (VIE). A VIE can be a corporation, partnership, trust, or any other legal structure used for business purposes. An entity is considered a VIE under FIN 46R if it does not have an equity investment sufficient for it to finance its activities without assistance from variable interests, if its equity investors do not have voting rights, or if the voting rights of equity investors are not proportionate to their economic rights.

FIN 46R requires us to consolidate VIEs for which we are the primary beneficiary and to disclose certain information about significant variable interests we hold. The primary beneficiary of a VIE is the entity that receives the majority of the entity's expected losses, residual returns, or both.

FIN 46R is effective March 31, 2004 for all VIEs except special purpose entities (SPEs), for which the effective date is December 31, 2003. Therefore, at December 31, 2003, we and BGE deconsolidated BGE Capital Trust II, an SPE established to issue Trust Preferred Securities as described in *Note 9*, because BGE is not its primary beneficiary. As a result, we removed the Trust Preferred Securities from our and BGE's Consolidated Balance Sheets and from our Consolidated Statements of Capitalization, recorded $257.7 million of Deferrable Interest Subordinated Debentures due to BGE Capital Trust II, and recorded our and BGE's $7.7 million equity investment in BGE Capital Trust II in "Other investments" in our and BGE's Consolidated Balance Sheets.

We are reviewing the impact of the provisions of FIN 46R on entities other than SPEs with which we are involved through variable interests. While we have not completed our review, in certain circumstances it is possible that the provisions of FIN 46R could require us to consolidate entities that hold power generating plants from which we have purchased power or to deconsolidate subsidiaries that hold power generating plants from which we have sold power. Upon completion of our review, the specific entities for which we are required to apply the provisions of FIN 46R, as well as the required application of those provisions, could differ from the results of our initial review, which are discussed below. Additionally, FIN 46R requires reconsideration of whether an entity is a VIE and the identity of its primary beneficiary in certain specified circumstances, including changes in the entity's governing documents, contracts, equity, or activities.

Based on our preliminary review of the provisions of FIN 46R and the entities with which we are involved through variable interests, we believe that we are the primary beneficiary of the Safe Harbor Water Power Corporation, a hydroelectric generating plant located in Pennsylvania. The other VIEs we have identified in which we have a significant interest include certain other power projects, fuel processing facilities, and a natural gas producing facility. We believe that we will not be required to consolidate these entities because we are not the primary beneficiary.

We had previously determined that we were the primary beneficiary for unconsolidated investments in a geothermal power project, the High Desert Power Project, and an office building in Annapolis, Maryland. In 2003, we acquired our partner's interest in the geothermal power project and consolidated the partnership under existing accounting requirements, we exercised our option under the High Desert lease, paid off the lease balance, and acquired the assets and liabilities, and we sold our interests in the office building. Therefore, FIN 46R no longer applies to these investments.

When we consolidate those VIEs for which we are the primary beneficiary, we will remove from our Consolidated Balance Sheets our previously recorded investment and record in our Consolidated Balance Sheets the total assets, liabilities and other ownership interests as reflected in the financial statements of those entities. We estimate that the net amount we will add to our Consolidated Balance Sheets will equal our recorded investment. As a result, we do not expect to record a cumulative effect of change in accounting principle upon adoption of FIN 46R in the first quarter of 2004. Upon adoption of FIN 46R, we will discontinue applying the equity method of accounting and begin recording in our Consolidated Statements of Income the revenues and expenses of those VIEs for which we are the primary beneficiary. This change will not affect our earnings.

The variable interests in entities in which we are involved generally consist of equity investments, guarantees of the entities' debt, and a natural gas producer swap with volumetric and price variability. The following is summary information about these entities as of December 31, 2003:

	Primary Beneficiary	Significant Interest	Total
		(In millions)	
Total assets	$125	$587	$712
Total liabilities	79	483	562
Our ownership interest	31	19	50
Other ownership interests	15	85	100
Our maximum exposure to loss	44	168	212

The maximum exposure to loss represents the loss that we would incur in the unlikely event that our interests in all of these entities were to become worthless and we were required to fund the full amount of all guarantees associated with these entities. Our maximum exposure to loss as of December 31, 2003 consists of the following:

- our recorded investment in these VIEs totaling $92 million,
- guarantees of the debt and letters of credit of these VIEs of $31 million and,
- volumetric and price variability of up to $89 million associated with a natural gas producer swap, based on contract volumes and gas prices as of December 31, 2003.

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

Accounting Standards Adopted

SFAS No. 132 Revised

In December 2003, the FASB issued a revised SFAS No. 132, *Employers' Disclosures about Pensions and Other Postretirement Benefits* (SFAS No. 132 Revised). SFAS No. 132 Revised does not change the measurement or recognition of pension and other postretirement benefit plans. It includes all of the disclosures required by the prior SFAS 132 and adds additional disclosures including information about the assets, obligations, and cash flows. It also requires disclosure of net periodic benefit cost recognized by cost component for interim periods. SFAS No. 132 Revised is effective December 31, 2003 and the additional disclosures are effective for this Form 10-K and are included in *Note 7*.

SFAS No. 133—DIG No. C20

In June 2003, the FASB cleared Derivatives Implementation Group Statement 133 Implementation Issue No. C20, *Interpretation of the Meaning of Not Clearly and Closely Related in Paragraph 10(b) regarding Contracts with a Price Adjustment Feature* (DIG C20). The scope of DIG C20 includes power and gas contracts that meet the definition of a derivative under SFAS No. 133. The provisions of DIG C20 provide guidance on determining whether any such contracts that include a price adjustment mechanism are eligible for accrual accounting under the normal purchase and normal sale exception to SFAS No. 133.

DIG C20 requires all entities to evaluate derivatives previously designated as normal purchases or normal sales to determine whether they previously should have been marked-to-market, and to record the fair value of any such contracts as a cumulative effect adjustment to earnings at the time of adoption. The provisions of DIG C20 were effective October 1, 2003. The effect of applying the provisions of DIG C20 was not material to our financial results.

SFAS No. 150

In May 2003, the FASB issued SFAS No. 150, *Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity*. The statement establishes standards for how an issuer classifies and measures certain financial instruments with characteristics of both liabilities and equity. However, in October 2003, the FASB deferred indefinitely the statement's provisions related to redeemable minority interests. SFAS No. 150 is effective for interim periods beginning after June 15, 2003, for financial instruments entered into or modified after May 31, 2003. Adoption of the provisions of this statement did not have a material impact on our financial results.

SFAS No. 149

In April 2003, the FASB issued SFAS No. 149, *Amendment of Statement 133 on Derivative Instruments and Hedging Activities*. The statement amends and clarifies SFAS No. 133 for certain interpretive guidance issued by the Derivatives Implementation Group. SFAS No. 149 was effective after June 30, 2003, for contracts entered into or modified and for hedges designated after the effective date. The adoption of this standard did not have a material impact on our financial results.

SFAS No. 143

In 2001, the FASB issued SFAS No. 143, *Accounting for Asset Retirement Obligations*. SFAS No. 143 provides the accounting requirements for recognizing an estimated liability for legal obligations associated with the retirement of tangible long-lived assets. Under SFAS No. 143, we are required to measure the liability at fair value when incurred and capitalize a corresponding amount as part of the book value of the related long-lived assets. The increase in the capitalized cost is included in determining depreciation expense over the estimated useful life of these assets. Since the fair value of the asset retirement obligations is determined using a present value approach, accretion of the liability due to the passage of time is recognized each period to "Accretion of asset retirement obligations" in our Consolidated Statements of Income until the settlement of the liability. We record a gain or loss when the liability is settled after retirement.

In the first quarter of 2003, we adopted this statement and recognized a $112.1 million pre-tax, or $67.7 million after-tax, gain as a cumulative effect of change in accounting principle.

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

As discussed earlier in this Note, we use the composite depreciation method for certain generating facilities and for our utility business. This method is an acceptable method of accounting under generally accepted accounting principles and is widely used in the energy, transportation, and telecommunication industries.

Historically, under the composite depreciation method, the anticipated costs of removing assets upon retirement are provided for over the life of those assets as a component of depreciation expense. However, SFAS No. 143 precludes the recognition of expected net future costs of removal as a component of depreciation expense unless they are legal obligations under SFAS No. 143. Instead, we must recognize these costs as incurred, unless the entity is rate regulated under SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation.*

For our merchant energy business, the elimination of net cost of removal accrued as part of depreciation expense prior to the implementation of SFAS No. 143 did not have a material impact on our financial results. However, 2003 depreciation expense was and future year depreciation expense will be lower than prior years since depreciation expense no longer includes a component for anticipated cost of removal in excess of salvage. Also, effective January 1, 2003, we only record those asset removal costs that represent legal obligations under SFAS No. 143 prior to their being incurred.

The adoption of SFAS No. 143 did not have a material impact on BGE's financial results. BGE is required by the Maryland PSC to use the composite depreciation method under regulatory accounting. BGE reclassified $108.4 million of net cost of removal from accumulated depreciation to a regulatory liability at December 31, 2002 to be comparable with the 2003 SFAS No. 143 presentation. In accordance with SFAS No. 71, BGE continues to accrue for the future cost of removal for its rate regulated gas and electric utility assets.

EITF 03-1

In December 2003, the EITF reached a consensus on Issue 03-1, *The Meaning of Other-Than-Temporary Impairment and Its Application to Certain Investments.* The consensus relates only to new disclosure requirements for debt and marketable equity investments that are accounted for under SFAS No. 115, *Accounting for Certain Investments in Debt and Equity Securities.* Companies are required to disclose quantitative and qualitative information regarding unrealized losses on debt and marketable equity investments. The disclosure requirements are effective for this Form 10-K and are included in *Note 4.*

EITF 03-11

In August 2003, the EITF reached a consensus on Issue 03-11, *Reporting Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133, Accounting for Derivative Instruments and Hedging Activities, and Not Held for Trading Purposes,* that reaffirmed existing revenue recognition requirements applicable to derivatives not designated as held for trading purposes. As a result, the implementation of EITF 03-11 did not affect our financial statements.

EITF 01-8

In May 2003, the EITF reached a consensus on Issue 01-8, *Determining Whether an Arrangement Contains a Lease.* EITF 01-8 provides guidance on how to determine when a contract contains a lease that is within the scope of SFAS No. 13 *Accounting for Leases,* and provides that any contract that conveys the right to control the use of property, plant, or equipment must be accounted for as a lease. EITF 01-8 applies to new contracts entered into after June 30, 2003. It also applies to any existing arrangements for which the contractual terms are modified or the underlying property, plant, or equipment undergoes a substantial physical change. The adoption of this standard did not have a material impact on our financial results.

EITF 02-3

In October 2002, the EITF reached a consensus on Issue 02-3, *Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities,* that changed the accounting for certain energy contracts. EITF 02-3 prohibits the use of mark-to-market accounting for any energy-related contracts that are not derivatives. Any non-derivative contracts must be accounted for on the accrual basis and recorded in the income statement gross rather than net upon application of EITF 02-3. This change applied immediately to new contracts executed after October 25, 2002 and applied to existing non-derivative energy-related contracts beginning January 1, 2003.

In the first quarter of 2003, we adopted EITF 02-3 and recognized a $430.0 million pre-tax, or $266.1 million after-tax, charge as a cumulative effect of change in accounting principle.

The primary contracts that were subject to the requirements of EITF 02-3 were our full requirements load-serving contracts and unit-contingent power purchase contracts, which are not derivatives. The majority of these contracts are in Texas and New England and were entered into prior to our shift to accrual accounting earlier in 2002.

To the extent permitted by SFAS No. 133, we designated derivative contracts used as supply sources and hedges to fulfill our load-serving contracts as either normal purchases or cash flow hedges under SFAS No. 133 effective January 1, 2003.

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

	Assets	Liabilities	Net
	(In millions)		
Mark-to-market energy contracts			
Current	$ 759.4	$ 709.6	$ 49.8
Noncurrent	926.8	460.0	466.8
Total	1,686.2	1,169.6	516.6
Other			
Current	85.7	56.8	28.9
Noncurrent	24.2	2.5	21.7
Total	109.9	59.3	50.6
Balance at December 31, 2002	$1,796.1	$1,228.9	$ 567.2

Impact of EITF 02-3 Adoption	
Non-derivative net asset reversed as cumulative effect of change in accounting principle	
Mark-to-market energy contracts	$(379.4)
Other	(50.6)
Total non-derivative net asset reversed as cumulative effect of change in accounting principle	(430.0)
Derivatives designated as hedges (net)	6.1
Derivatives designated as normal purchases and sales (net)	(64.3)
Net mark-to-market derivatives remaining after adoption of EITF 02-3 on January 1, 2003	$ 79.0

On January 1, 2003, we recorded the $430.0 million non-derivative net asset removed from our Consolidated Balance Sheets as a cumulative effect of change in accounting principle, which reduced our 2003 net income by $266.1 million as previously discussed. The $430.0 million represents $379.4 million of non-derivative contracts recorded as "Mark-to-market energy assets and liabilities" and $50.6 million of "Other assets and liabilities" primarily from the re-designation of Texas contracts to accrual accounting in 2002. The fair value of these contracts will be recognized in earnings as power is delivered.

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

After the adoption of EITF 02-3 on January 1, 2003, net mark-to-market derivatives of $79.0 million, which consisted of $1,099.8 million in assets and $1,020.8 million in liabilities, remained in our Consolidated Balance Sheets. Applying EITF 02-3 does not affect our cash flows or our accounting for new load-serving contracts for which we have used accrual accounting since early 2002.

FIN 45

In November 2002, the FASB issued FIN 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness to Others.* This Interpretation provides the disclosures to be made by a guarantor in interim and annual financial statements about obligations under certain guarantees. The Interpretation also clarifies that a guarantor is required to recognize, at the inception of a guarantee, a liability for the fair value of the obligation. The adoption of this standard did not have a material impact on our financial results.

2 Workforce Reduction, Impairment Losses, Contract Termination, and Other Events

2003 Events

	Pre-Tax	After-Tax
	(In millions)	
Workforce reduction costs	$(2.1)	$(1.3)
Reduction of financial investment	(0.6)	(0.4)
Net gain on sales of investments and other assets	26.2	16.4
Total special items	$23.5	$14.7

Workforce Reduction Costs

During 2003, we recorded $2.1 million in pre-tax expense, or $1.3 million after-tax, of which BGE recorded $0.7 million pre-tax, associated with deferred payments to employees eligible for the 2001 Voluntary Special Early Retirement Program.

In 2002, we recorded $14.9 million of expenses for anticipated involuntary severance costs in accordance with Emerging Issues Task Force (EITF) 94-3, *Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)*, associated with new workforce reduction initiatives in 2002. The following table summarized the status of the involuntary severance liability recorded under EITF 94-3:

	(In millions)
Severance liability balance at December 31, 2002	$ 14.9
Cash severance payments in first quarter	(10.5)
Cash severance payments in second quarter	(1.3)
Cash severance payments in third quarter	(0.7)
Cash severance payments in fourth quarter	(0.4)
Severance costs recorded as postretirement benefit liability	(1.2)
Severance liability balance at December 31, 2003	$ 0.8

Impairment Losses and Other Costs

In 2003, our other nonregulated businesses recognized an impairment loss of $0.6 million pre-tax, or $0.4 million after-tax, related to the decline in value of our investment in an airplane.

Net Gain on Sales of Investments and Other Assets

During 2003, our other nonregulated businesses recognized $26.2 million of pre-tax, or $16.4 million after-tax, gains on the sales of non-core assets as follows:

- a $13.1 million pre-tax gain on the sale of certain real estate,
- a $7.2 million pre-tax gain on the sale of an oil tanker to the U.S. Navy,
- a $5.3 million pre-tax gain on the favorable settlement of a contingent obligation we had previously reserved relating to the sale of our Guatemalan power plant operation in the fourth quarter of 2001, and
- a $0.6 million pre-tax gain on the sale of financial investments.

Hurricane Isabel

In September 2003, Hurricane Isabel caused damage to the electric and gas distribution system of BGE. As a result, BGE incurred capitalized costs of $32.0 million and maintenance expenses of $36.8 million, or $22.2 million after-tax to restore its distribution system. The maintenance expenses included $32.1 million pre-tax, or $19.4 million after-tax, of incremental expenses.

2002 Events

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

Workforce Reduction Costs

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

Costs associated with 2001 Programs

In 2002, we recorded $63.7 million of net workforce reduction costs associated with our 2001 workforce reduction initiatives as discussed below. The $63.7 million included $50.8 million recognized as expense, of which BGE recognized $33.8 million. The remaining $12.9 million was recognized by BGE as a regulatory asset related to its gas business as discussed in *Note 6*.

- We recorded $52.9 million when 308 employees elected the age 50 to 54 Voluntary Special Early Retirement Program (VSERP).
- We reversed $17.8 million of the $25.1 million involuntary severance accrual that was recorded in 2001 to reflect the employees that elected the age 50 to 54 VSERP. Ultimately, we involuntarily severed 129 employees that resulted in a total cost for the involuntary severance program of $7.3 million.

- We recorded $29.6 million of settlement charges related to our pension plans under SFAS No. 88, *Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits*. These charges reflect the recognition of actuarial gains and losses associated with employees who have retired and taken their pension in the form of a lump-sum payment. Under SFAS No. 88, the settlement charge could not be recognized until lump-sum pension payments exceeded annual pension plan service and interest cost, which occurred in 2002.
- We recorded a $1.6 million expense associated with deferred payments to employees eligible for the VSERP.
- Partially offsetting these costs, we reversed approximately $2.6 million of previously accrued workforce reduction costs primarily as a result of the reversal of education and outplacement assistance benefits we accrued that employees did not utilize to the extent expected.

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

Costs associated with 2002 Programs

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

- We recorded $8.5 million for workforce reduction costs for the severance of 120 employees at Calvert Cliffs Nuclear Power Plant (Calvert Cliffs).
- We recorded $1.6 million of workforce reduction costs for the severance of 27 employees in our information technology organization. BGE recorded $0.6 million of this amount.
- We recorded $1.9 million of workforce reduction costs for the severance of 20 employees in our legal organization. BGE recorded $0.9 million of this amount.

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

Impairment Losses and Other Costs

Investments in Qualifying Facilities and Power Projects

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

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

- We recognized a $5.2 million other than temporary decline in value of our investment in a partnership that owns a geothermal project in Nevada. This project experienced a well implosion and we believe that the expected cash flows from the project will not be sufficient to recover our equity interest in that partnership.
- We recognized a $2.6 million other than temporary decline in value of our investment in a fuel processing site in Pennsylvania where the expected cash flows from a sublease are no longer expected to be sufficient to recover our lease costs associated with this site.
- We recognized a $6.6 million other than temporary decline in value of our investment in a partnership that owns a waste burning power project in Michigan. In 2001, we recognized a $6.1 million pre-tax impairment loss on this investment because we expected operating cash flows would not be sufficient to pay existing debt service and that we would not be able to recover our equity investment. However, at that time, we believed that we would recover our senior working capital loans receivable and accounts receivable for operating the project. As of the third quarter of 2002, the operating performance of the project did not improve as expected, and we believed the expected future cash flows were no longer sufficient to recover these receivables. Therefore, we recognized an additional impairment loss on this investment.

Closing of BGE Home Retail Merchandise Stores

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

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

Real Estate and International Investments

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

Net Gain on Sales of Investments and Other Assets

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

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

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

2001 Events

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

Workforce Reduction Costs

Voluntary Special Early Retirement Programs—VSERP

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

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

Settlement and Curtailment Charges
In connection with the age 55 or older VSERP, a significant number of the participants in our nonqualified pension plans retired. As a result, we recognized a settlement loss of approximately $10.5 million and a curtailment loss of approximately $5.8 million for those plans in accordance with SFAS No. 88. BGE recorded $6.6 million of this amount. Additional details on the VSERP and their impact on our pension and postretirement benefit plans are discussed in *Note 7.*

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

In accordance with EITF 94-3, the Company recognized a liability of $25.1 million at December 31, 2001 for the targeted number of involuntary terminations that would have resulted if no employees elected the age 50 to 54 VSERP. The $19.3 million in the table on the previous page represents involuntary severance charged to expense in 2001 in connection with our workforce reduction programs. BGE recorded $12.5 million of this amount. BGE also recorded $5.8 million on its balance sheet as a regulatory asset related to its gas business as discussed in *Note 6.*

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

We also announced the termination of our power business services agreement with Goldman Sachs. We paid Goldman Sachs a total of $355 million, representing $196.7 million to terminate the power business services agreement with our wholesale marketing and risk management operation and $159 million previously recognized as a payable for services rendered under the agreement.

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

Impairment Losses and Other Costs
Cancellation of Domestic Power Projects
In the fourth quarter of 2001, our merchant energy business recorded impairments of $46.9 million primarily due to $40.8 million in impairments associated with the termination of our planned development projects in Texas, California, Florida, and Massachusetts not under construction. We decided to terminate our development projects due to the expected excess generation capacity in most domestic markets and the significant decline in the forward market prices of electricity. The impairments include amounts paid for the purchase of four turbines related to these development projects. In addition, we recognized $6.1 million for an other than temporary decline in the value of our investment in a waste burning power plant in Michigan where operating cash flows are not sufficient to pay existing debt service and we are not likely to recover our equity interest in this investment.

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

- We decided to sell six real estate projects without further development and all of our 18 senior-living facilities in 2002 and accelerate the exit strategies for two other real estate projects that we will continue to hold and own over the next several years. The real estate projects include approximately 1,300 acres of land holdings in various stages of development located in seven sites in the central Maryland region and an operating waste water treatment plant located in Anne Arundel County, Maryland. In 2002, we sold approximately 800 acres of land holdings.

- We decided to accelerate the exit strategy for our interest in a Panamanian electric distribution company. As a non-core asset, management has decided to reduce the cost and risk of holding this asset indefinitely and intends to dispose of this asset.
- We incurred an other than temporary decline in our equity-method investment in the Bolivian Generating Group, which owns an interest in an electric generation concession in Bolivia. This decline in value resulted from a deterioration of our investment's position in the dispatch curve of its capacity market. As a result, we recorded the impairment in accordance with the provisions of Accounting Principles Board Opinion No. 18.

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

Reduction of Financial Investment

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

Net Gain on Sales of Investments and Other Assets

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

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

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

3 Information by Operating Segment

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

- Our nonregulated merchant energy business in North America includes:
  - fossil, nuclear, and hydroelectric generating facilities and interests in qualifying facilities, fuel processing facilities, and power projects in the United States,
  - origination of structured transactions (such as load-serving and power purchase agreements), and risk management services to various customers (including hedging of output from generating facilities and fuel costs),
  - electric and gas retail energy services to commercial and industrial customers, and
  - generation and consulting services.
- Our regulated electric business purchases, transmits, distributes, and sells electricity in Maryland.
- Our regulated gas business purchases, transports, and sells natural gas in Maryland.

Our remaining nonregulated businesses:

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

In addition, we own several investments that we do not consider to be core operations. These include financial investments, real estate projects, and interests in a Latin American power distribution project and in a fund that holds interests in two South American energy projects.

Our Merchant Energy, Regulated Electric, and Regulated Gas reportable segments are strategic businesses based principally upon regulations, products, and services that require different technology and marketing strategies. We evaluate the performance of these segments based on net income. We account for intersegment revenues using market prices. We present a summary of information by operating segment on the next page.

	Reportable Segments					
	Merchant Energy Business	Regulated Electric Business	Regulated Gas Business	Other Nonregulated Businesses	Eliminations	Consolidated
				(In millions)		
2003						
Unaffiliated revenues	$ 6,481.1	$1,921.5	$ 712.7	$ 587.7	$ —	$ 9,703.0
Intersegment revenues	1,167.0	0.1	13.3	0.2	(1,180.6)	—
Total revenues	7,648.1	1,921.6	726.0	587.9	(1,180.6)	9,703.0
Depreciation and amortization	229.5	181.7	46.6	21.2	—	479.0
Fixed charges	191.9	96.8	28.2	21.0	2.3	340.2
Income tax expense	146.9	75.5	32.5	14.6	—	269.5
Cumulative effects of changes in accounting principles	(198.4)	—	—	—	—	(198.4)
Net income (a)	114.6	107.5	43.0	12.2	—	277.3
Segment assets	10,711.4	3,512.0	1,069.1	778.7	(270.5)	15,800.7
Capital expenditures	419.0	236.0	53.0	53.0	—	761.0
2002						
Unaffiliated revenues	$ 1,653.2	$1,965.6	$ 570.5	$ 537.4	$ —	$ 4,726.7
Intersegment revenues	1,136.2	0.4	10.8	—	(1,147.4)	—
Total revenues	2,789.4	1,966.0	581.3	537.4	(1,147.4)	4,726.7
Depreciation and amortization	242.8	174.2	47.4	16.6	—	481.0
Fixed charges	102.0	128.4	25.9	25.2	—	281.5
Income tax expense	127.2	67.1	22.4	92.9	—	309.6
Net income (b)	247.2	99.3	31.1	148.0	—	525.6
Segment assets	9,680.4	3,565.1	1,140.4	913.0	(355.6)	14,943.3
Capital expenditures	641.0	167.0	50.0	65.0	—	923.0
2001						
Unaffiliated revenues	$ 614.3	$2,039.6	$ 674.3	$ 550.6	$ —	$ 3,878.8
Intersegment revenues	1,151.2	0.4	6.4	2.0	(1,160.0)	—
Total revenues	1,765.5	2,040.0	680.7	552.6	(1,160.0)	3,878.8
Depreciation and amortization	174.9	173.3	47.7	23.2	—	419.1
Fixed charges	25.8	135.8	28.5	48.7	—	238.8
Income tax expense (benefit)	25.2	36.8	25.7	(49.8)	—	37.9
Cumulative effect of change in accounting principle	—	—	—	8.5	—	8.5
Net income (loss) (c)	93.1	50.9	37.5	(90.6)	—	90.9
Segment assets	8,694.3	3,764.9	1,104.2	1,331.7	(197.6)	14,697.5
Capital expenditures	1,044.0	180.3	58.7	35.0	—	1,318.0

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

(a) Our merchant energy business, our regulated electric business, our regulated gas business, and our other nonregulated businesses recognized after-tax charges (income) of $0.7 million, $0.4 million, $0.1 million, and ($15.9 million), respectively, for workforce reduction costs, impairment losses and other costs, and net gains on sales of investments and other assets as described in more detail in Note 2.

(b) Our merchant energy business, our regulated electric business, our regulated gas business, and our other nonregulated businesses recognized after-tax charges (income) of $28.3 million, $20.5 million, $0.8 million, and ($161.1 million), respectively, for workforce reduction costs, business exit costs, impairment losses and other costs, and net gains on sales of investments and other assets as described in more detail in Note 2.

(c) Our merchant energy business, our regulated electric business, our regulated gas business, and our other nonregulated businesses recognized after-tax charges of $198.1 million, $33.6 million, $0.8 million, and $72.3 million, respectively, for workforce reduction costs, contract termination related costs, impairment losses and other costs, and a net gain on sales of investments and other assets as described in more detail in Note 2.

4 Investments

Real Estate Projects and Investments

Real estate projects and investments recorded in "Other investments" consist of the following:

At December 31,	**2003**	2002
	(In millions)	
Operating properties and properties under development	**$44.3**	$77.8
Equity interest in real estate investments	**—**	8.3
Total real estate projects and investments	**$44.3**	$86.1

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

See *Note 2* for a discussion of impairments recorded in 2002 and 2001.

Investments in Qualifying Facilities and Power Projects

Our merchant energy business holds up to a 50% ownership interest in 25 operating domestic energy projects that consist of electric generation, fuel processing, or fuel handling facilities. Of these 25 projects, 18 are "qualifying facilities" that receive certain exemptions and pricing under the Public Utility Regulatory Policy Act of 1978 based on the facilities' energy source or the use of a cogeneration process.

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

At December 31,	**2003**	2002
	(In millions)	
Coal	**$130.5**	$133.9
Hydroelectric	**57.3**	62.6
Geothermal*	**56.0**	151.4
Biomass	**51.4**	52.6
Fuel Processing	**22.5**	23.2
Solar	**10.5**	10.5
Total	**$328.2**	$434.2

**During 2003, we acquired the minority interest from our partner in a geothermal project and removed the equity-method investment in the project and consolidated the assets and liabilities of the project in our Consolidated Balance Sheets.*

The investment in qualifying facilities and domestic power projects were accounted for under the following methods:

At December 31,	**2003**	2002
	(In millions)	
Equity method	**$317.6**	$423.7
Cost method	**10.6**	10.5
Total power projects	**$328.2**	$434.2

Our percentage voting interest in qualifying facilities and domestic power projects accounted for under the equity method ranges from 16% to 50%. Equity in earnings of these power projects were $2.1 million in 2003, $9.1 million in 2002, and $23.1 million in 2001.

Our power projects accounted for under the equity method include investments of $251.8 million in 2003 and $260.6 million in 2002 that sell electricity in California under power purchase agreements called "Interim Standard Offer No. 4" agreements.

Our other nonregulated businesses also held international energy projects accounted for under the equity method of $4.4 million at December 31, 2003 and $5.0 million at December 31, 2002.

See *Note 2* for a discussion of impairments recorded in 2002 and 2001.

Financial Investments

Financial investments recorded in "Other investments" consist of the following:

At December 31,	**2003**	2002
	(In millions)	
Financial limited partnerships	**$22.5**	$24.2
Leveraged leases	**2.8**	12.7
Total financial investments	**$25.3**	$36.9

Investments Classified as Available-for-Sale

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

- nuclear decommissioning trust funds, and
- trust assets securing certain executive benefits.

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

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

At December 31, 2003	Amortized Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value
		(In millions)		
Marketable equity securities	$644.8	$35.7	$(26.9)	$653.6
Corporate debt and U.S. treasuries	39.6	0.8	(0.1)	40.3
State municipal bonds	46.0	4.2	—	50.2
Totals	$730.4	$40.7	$(27.0)	$744.1

At December 31, 2002	Amortized Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value
		(In millions)		
Marketable equity securities	$642.6	$18.9	$(69.2)	$592.3
Corporate debt and U.S. treasuries	51.5	1.7	(0.1)	53.1
State municipal bonds	22.0	1.3	—	23.3
Totals	$716.1	$21.9	$(69.3)	$668.7

In addition to the above securities, the nuclear decommissioning trust funds included $17.2 million at December 31, 2003 and $14.0 million at December 31, 2002 of cash and cash equivalents.

The preceding tables include $13.7 million in 2003 of net unrealized gains and $47.4 million in 2002 of net unrealized losses associated with the nuclear decommissioning trust funds that are reflected as a change in the nuclear decommissioning trust funds in our Consolidated Balance Sheets.

We have unrealized losses relating to certain available-for-sale investments included in our decommissioning trust funds. We believe these losses are a result of the general downturn of the economy and expect the investments to recover their value in the future given the long-term nature of these investments. Decommissioning costs will not be incurred until the operating licenses for our nuclear facilities expire. We show the fair values and unrealized losses of our investments that were in a loss position at December 31, 2003.

	Less than 12 months		12 months or more		Total	
Description of Securities	Fair Value	Unrealized Losses	Fair Value	Unrealized Losses	Fair Value	Unrealized Losses
			(In millions)			
Marketable equity securities	$71.8	$(12.3)	$414.7	$(14.6)	$486.5	$(26.9)
Corporate debt and U.S. treasuries	18.3	(0.1)	—	—	18.3	(0.1)
Total temporarily impaired securities	$90.1	$(12.4)	$414.7	$(14.6)	$504.8	$(27.0)

Gross and net realized gains and losses on available-for-sale securities, excluding the gains on our sales of the Orion investment, were as follows:

	2003	2002	2001
		(In millions)	
Gross realized gains	$ 6.7	$ 6.0	$47.6
Gross realized losses	(6.1)	(9.5)	(7.9)
Net realized (losses) gains	$ 0.6	$ (3.5)	$39.7

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

At December 31, 2003	Amount
	(In millions)
Less than 1 year	$ —
1-5 years	37.8
5-10 years	36.7
More than 10 years	16.0
Total maturities of debt securities	$90.5

5 Intangible Assets

Goodwill

Goodwill is the cost of an acquisition less the fair value of the net assets acquired. The changes in the carrying amount of goodwill at our merchant energy business for the years ended December 31, 2003 and 2002 are as follows:

2003	Balance at January 1,	Goodwill Acquired	Other(a)	Balance at December 31,
		(In millions)		
Goodwill	$115.9	$27.5	$0.6	$144.0

2002	Balance at January 1,	Goodwill Acquired	Other(a)	Balance at December 31,
		(In millions)		
Goodwill	$ —	$115.9	$ —	$115.9

(a) Other represents purchase price adjustments

Goodwill is not amortized, rather it is evaluated for impairment at least annually. We evaluated our goodwill in 2003 and no impairment was recorded. We discuss our acquisitions in more detail in *Note 15.*

Intangible Assets Subject to Amortization

Intangible assets with finite lives are subject to amortization over their estimated useful lives. The primary assets included in this category are as follows:

At December 31,	2003			2002		
	Gross Carrying Amount	Accumulated Amortization	Net Asset	Gross Carrying Amount	Accumulated Amortization	Net Asset
			(In millions)			
Software	$285.6	$155.1	$130.5	$225.1	$111.8	$113.3
Acquired energy contracts (net)	182.5	36.7	145.8	106.1	1.5	104.6
Permits and licenses	28.8	3.2	25.6	48.7	12.7	36.0
Operating manuals and procedures	12.5	2.7	9.8	22.3	2.5	19.8
Other	22.6	10.7	11.9	21.5	7.7	13.8
Total	$532.0	$208.4	$323.6	$423.7	$136.2	$287.5

Acquired energy contracts (net) represent the fair value of a contract at the time of contract acquisition, which includes contracts acquired as part of a business, asset, or portfolio acquisition. Acquired energy contracts (net) can either be an asset or a liability. We are currently in a net asset position.

We recognized amortization expense related to our intangible assets as follows:

- $84.6 million during 2003
- $46.4 million during 2002, and
- $36.1 million during 2001.

The following is our estimated amortization expense for 2004 through 2008 for the intangible assets included in our Consolidated Balance Sheets at December 31, 2003:

Year Ended December 31,	2004	2005	2006	2007	2008
			(In millions)		
Estimated amortization expense	$103.0	$58.1	$40.4	$29.7	$30.0

6 Regulatory Assets (net)

As discussed in *Note 1*, the Maryland PSC and the FERC provide the final determination of the rates we charge our customers for our regulated businesses. Generally, we use the same accounting policies and practices used by nonregulated companies for financial reporting under accounting principles generally accepted in the United States of America. However, sometimes the Maryland PSC or FERC orders an accounting treatment different from that used by nonregulated companies to determine the rates we charge our customers. When this happens, we must defer certain 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,	2003	2002
	(In millions)	
Electric generation-related regulatory asset	$ 211.3	$ 230.1
Net cost of removal	(147.8)	(108.4)
Income taxes recoverable through future rates (net)	81.8	88.8
Deferred postretirement and postemployment benefit costs	29.0	32.3
Deferred environmental costs	20.4	23.2
Deferred fuel costs (net)	11.9	1.9
Workforce reduction costs	21.2	28.2
Other (net)	1.7	1.2
Total regulatory assets (net)	$ 229.5	$ 297.3

Electric Generation-Related Regulatory Asset

As a result of the deregulation of electric generation, BGE no longer met the requirements for the application of SFAS No. 71 for the electric generation portion of its business. In accordance with SFAS No. 101, *Regulated Enterprises—Accounting for the Discontinuation of Application of FASB Statement No. 71*, and EITF 97-4, *Deregulation of the Pricing of Electricity—Issues Related to the Application of FASB Statements No. 71 and 101*, all individual generation-related regulatory assets and liabilities must be eliminated from our balance sheet unless these regulatory assets and liabilities will be recovered in the regulated portion of the business. BGE wrote-off all of its individual, generation-related regulatory assets and liabilities. BGE established a single, new generation-related regulatory asset for amounts to be collected through its regulated transmission and distribution business. The new regulatory asset is being amortized on a basis that approximates the pre-existing individual regulatory asset amortization schedules.

A portion of this regulatory asset represents the decommissioning and decontamination fund payment for federal uranium enrichment facilities that do not earn a return on the rate base investment. These amounts were $13.4 million at December 31, 2003, and $16.3 million at December 31, 2002. Prior to the deregulation of electric generation, these costs were recovered through the electric fuel rate mechanism, and were excluded from rate base. We will continue to amortize this amount through 2008.

Net Cost of Removal

As discussed in *Note 1*, we use the composite depreciation method for the utility business. This method is currently an acceptable method of accounting under accounting principles generally accepted in the United States of America and is widely used in the energy, transportation, and telecommunication industries.

Historically, under the composite depreciation method, the anticipated costs of removing assets upon retirement were provided for over the life of those assets as a component of depreciation expense. However, effective January 1, 2003, we adopted SFAS No. 143, *Accounting for Asset Retirement Obligations*. In addition to providing the accounting requirements for recognizing an estimated liability for legal obligations associated with the retirement of tangible long-lived assets, SFAS No. 143 precludes the recognition of expected net future costs of removal as a component of depreciation expense or accumulated depreciation.

BGE is required by the Maryland PSC to use the composite depreciation method, including cost of removal, under regulatory accounting. In accordance with SFAS No. 71, BGE continues to accrue for the future cost of removal for its regulated gas and electric utility assets increasing its regulatory liability. This liability is relieved when actual removal costs are incurred.

Income Taxes Recoverable Through Future Rates (net)

As described in *Note 1*, income taxes recoverable through future rates are the portion of our net deferred income tax liability that is applicable to our regulated utility business, but has not been reflected in the rates we charge our customers. These income taxes represent the tax effect of temporary differences in depreciation and the allowance for equity funds used during construction, offset by differences in deferred tax rates and deferred taxes on deferred investment tax credits. We amortize these amounts as the temporary differences reverse.

Deferred Postretirement and Postemployment Benefit Costs

Deferred postretirement and postemployment benefit costs are the costs we recorded under SFAS No. 106, *Employers' Accounting for Postretirement Benefits Other Than Pensions*, and SFAS No. 112, *Employers' Accounting for Postemployment Benefits*, in excess of the costs we included in the rates we charge our customers. We began amortizing these costs over a 15-year period in 1998. We discuss these costs further in *Note 7*.

Deferred Environmental Costs

Deferred environmental costs are the estimated costs of investigating and cleaning up contaminated sites we own. We discuss this further in *Note 12*. We are amortizing $21.6 million of these costs (the amount we had incurred through October 1995) and $6.4 million of these costs (the amount we incurred from November 1995 through June 2000) over 10-year periods in accordance with the Maryland PSC's orders.

Deferred Fuel Costs

As described in *Note 1*, deferred fuel costs are the difference between our actual costs of natural gas and our fuel rate revenues collected from customers. We reduce deferred fuel costs as we collect them from or refund them to our customers.

In December 2002, a Hearing Examiner from the Maryland PSC issued a proposed order related to our annual gas adjustment clause review disallowing $7.7 million of a previously established regulatory asset of $9.4 million for certain credits that were over-refunded to customers through our market-based rates. BGE reserved the $7.7 million as disallowed fuel costs in the fourth quarter of 2002. In August 2003, the Maryland PSC issued an order authorizing us to recover the $7.7 million and we reinstated the $9.4 million regulatory asset.

We exclude gas deferred fuel costs from rate base because their existence is relatively short-lived. These costs are recovered in the following year through our gas cost adjustment clauses.

Workforce Reduction Costs

The portions of the costs associated with our VSERP and workforce reduction programs that relate to BGE's gas business are deferred as regulatory assets in accordance with the Maryland PSC's orders in prior rate cases. These costs are amortized over 5-year periods. See *Note 2* and *Note 7*.

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

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

We use a December 31 measurement date for our pension, postretirement, other postemployment, and employee savings plans.

Pension Benefits

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

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

We fund the qualified plans by contributing at least the minimum amount required under Internal Revenue Service (IRS) regulations. We calculate the amount of funding using an actuarial method called the projected unit credit cost method. The assets in all of the plans at December 31, 2003 were mostly marketable equity and fixed income securities.

Postretirement Benefits

We sponsor defined benefit postretirement health care and life insurance plans that cover the vast majority of our employees. Generally, we calculate the benefits under these plans based on age, years of service, and pension benefit levels. 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. The adoption of that statement caused:

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

For our regulated utility business, we accounted for the increase in annual postretirement benefit costs under two Maryland PSC rate orders:

- in an April 1993 rate order, the Maryland PSC allowed us to expense one-half and defer, as a regulatory asset (see *Note 6*), the other half of the increase in annual postretirement benefit costs related to our regulated electric and gas businesses, and
- in a November 1995 rate order, the Maryland PSC allowed us to expense all of the increase in annual postretirement benefit costs related to our regulated gas business.

Beginning in 1998, the Maryland PSC authorized us to:

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

Effective in 2002, we amended our postretirement medical plans for all affiliates other than Nine Mile Point. Our contributions for retiree medical coverage for future retirees that were under the age of 55 on January 1, 2002 are capped at the 2002 level. We also amended our plans to increase the Medicare eligible retirees' share of medical costs.

In 2003, the President signed into law the Medicare Prescription Drug Improvement and Modernization Act of 2003. This legislation provides a prescription drug benefit for Medicare beneficiaries, a benefit that we provide to our Medicare eligible retirees. We are currently evaluating the provisions of this Act, and thus we have not reflected the effects in our Consolidated Financial Statements or related disclosures. If our retiree drug program is determined to be actuarially equivalent to the Medicare Part D program in the Act, we may be eligible for a federal subsidy. Pending authoritative guidance on accounting for that subsidy could require us to change previously reported information.

VSERP

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

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

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

The age 50 to 54 program allowed employees to make their elections beginning in 2002. The cost of that program was approximately $52.9 million ($43.0 million in pension termination costs, $8.5 million in postretirement benefit costs, and $1.4 million in education and outplacement assistance costs). Of this amount, BGE recorded approximately $13.4 million on its balance sheet as a regulatory asset of its gas business. We incurred approximately $0.7 million of postretirement benefit costs related to additional workforce reduction initiatives in 2002.

In connection with the retirement of a significant number of the participants in the nonqualified pension plans we recognized a settlement loss of approximately $10.5 million and a curtailment loss of approximately $5.8 million for those plans in accordance with SFAS No. 88 in 2001. We recorded additional settlement charges of $29.6 million related to our qualified and nonqualified pension plans in 2002 as a result of retirees electing to take their pension benefit in the form of a lump-sum payment.

Although not in connection with any type of workforce reduction initiative, lump-sum payments made to employees retiring in 2003 were high enough to result in a $2.8 million settlement charge for our Nine Mile Point qualified pension plan.

Our pension accumulated benefit obligation has exceeded the fair value of our plan assets since 2001. At December 31, 2003 and 2002, our pension obligations were greater than the fair value of our plan assets for our qualified and our nonqualified pension plans as follows:

At December 31, 2003	Qualified Plans Nine Mile	Qualified Plans Other	Non-Qualified Plans	Total
	(In millions)			
Accumulated benefit obligation	$98.3	$1,044.9	$37.1	$1,180.3
Fair value of assets	66.7	887.9	—	954.6
Unfunded obligation	$31.6	$ 157.0	$37.1	$ 225.7

At December 31, 2002	Qualified Plans Nine Mile	Qualified Plans Other	Non-Qualified Plans	Total
	(In millions)			
Accumulated benefit obligation	$85.7	$981.6	$35.0	$1,102.3
Fair value of assets	57.8	709.9	—	767.7
Unfunded obligation	$27.9	$271.7	$35.0	$ 334.6

As required under SFAS No. 87, we recorded additional minimum pension liability adjustments as follows:

	Increase (Decrease)			
	Pension Liability Adjustment	Intangible Asset *	Accumulated Other Comprehensive Income (Loss) Pre-tax	Accumulated Other Comprehensive Income (Loss) After-tax
		(In millions)		
2001	$133.0	$59.0	$ (74.0)	$ (44.7)
2002	189.5	(5.8)	(195.3)	(118.1)
2003	(27.3)	(6.5)	20.8	12.6
Total	$295.2	$46.7	$(248.5)	$(150.2)

* *Included in "Other deferred charges" in our Consolidated Balance Sheets.*

The cost of the voluntary retirement programs and the settlement and curtailment losses are not included in the tables of net periodic pension and postretirement benefit costs for the respective years.

Obligations, Assets, and Funded Status

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

	Pension Benefits 2003	Pension Benefits 2002	Postretirement Benefits 2003	Postretirement Benefits 2002
	(In millions)			
Change in benefit obligation				
Benefit obligation at January 1	**$1,247.5**	$1,259.2	**$415.4**	$ 475.2
Service cost	**33.7**	29.6	**6.1**	5.0
Interest cost	**81.3**	82.2	**26.3**	26.7
Plan participants' contributions	**—**	—	**6.1**	4.7
Actuarial loss	**76.0**	78.9	**11.4**	34.9
Plan amendments	**(0.4)**	—	**—**	(110.3)
VSERP charge	**—**	43.0	**—**	9.2
Settlement of liability	**—**	(37.9)	**—**	—
Benefits paid	**(112.1)**	(207.5)	**(34.5)**	(30.0)
Benefit obligation at December 31	**$1,326.0**	$1,247.5	**$430.8**	$ 415.4

	Pension Benefits 2003	Pension Benefits 2002	Postretirement Benefits 2003	Postretirement Benefits 2002
	(In millions)			
Change in plan assets				
Fair value of plan assets at January 1	**$ 767.7**	$ 912.2	**$ —**	$ —
Actual return on plan assets	**183.6**	(89.4)	**—**	—
Employer contribution	**115.4**	152.4	**28.4**	25.3
Plan participants' contributions	**—**	—	**6.1**	4.7
Benefits paid	**(112.1)**	(207.5)	**(34.5)**	(30.0)
Fair value of plan assets at December 31	**$ 954.6**	$ 767.7	**$ —**	$ —

	Pension Benefits		Postretirement Benefits	
	2003	2002	**2003**	2002
	(In millions)			
Funded Status				
Funded Status at December 31	**$(371.4)**	$(479.8)	**$(430.8)**	$(415.4)
Unrecognized net actuarial loss	**397.0**	417.8	**140.6**	135.5
Unrecognized prior service cost	**43.9**	49.9	**(40.2)**	(43.8)
Unrecognized transition obligation	**—**	—	**19.2**	21.3
Pension liability adjustment	**(295.2)**	(322.5)	**—**	—
Accrued benefit cost	**$(225.7)**	$(334.6)	**$(311.2)**	$(302.4)

Net Periodic Benefit Cost

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

Year Ended December 31,	**2003**	2002	2001
		(In millions)	
Components of net periodic pension benefit cost			
Service cost	**$33.7**	$29.6	$ 25.8
Interest cost	**81.3**	82.2	76.1
Expected return on plan assets	**(95.0)**	(91.0)	(87.5)
Amortization of transition obligation	**—**	—	(0.2)
Amortization of prior service cost	**5.8**	6.7	6.5
Recognized net actuarial loss	**5.0**	1.3	2.8
Amount capitalized as construction cost	**(2.6)**	(2.9)	(2.5)
Net periodic pension benefit cost	**$28.2**	$25.9	$ 21.0

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

Year Ended December 31,	**2003**	2002	2001
		(In millions)	
Components of net periodic postretirement benefit cost			
Service cost	**$ 6.1**	$ 5.0	$ 8.4
Interest cost	**26.3**	26.7	29.2
Amortization of transition obligation	**2.1**	2.1	7.9
Recognized net actuarial loss	**5.8**	6.4	3.3
Amortization of unrecognized prior service cost	**(3.5)**	(3.5)	—
Amount capitalized as construction cost	**(8.8)**	(9.1)	(14.5)
Net periodic postretirement benefit cost	**$ 28.0**	$27.6	$ 34.3

Assumptions

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

	Pension Benefits		Postretirement Benefits		Assumption Impacts
	2003	2002	**2003**	2002	Calculation of
Discount rate	**6.25%**	6.75%	**6.25%**	6.75%	Benefit Obligation and Periodic Cost
Expected return on plan assets	**9.0**	9.0	**N/A**	N/A	Periodic Cost
Rate of compensation increase	**4.0**	4.0	**4.0**	4.0	Benefit Obligation and Periodic Cost

Our 9.0% overall expected long-term rate of return on plan assets reflects our long-term investment strategy in terms of asset mix targets and expected returns for each asset class.

Annual health care inflation rate assumptions also impact the calculation of our postretirement benefit obligation and periodic cost. We assumed the following health care inflation rates:

At December 31,	**2003**	2002
Next year	**8.0%**	11.0%
Following year	**6.0%**	8.0%
Ultimate trend rate	**5.0%**	5.0%
Year ultimate trend rate reached	**2010**	2010

A one-percent increase in the health care inflation rate from the assumed rates would increase the accumulated postretirement benefit obligation by approximately $34.1 million as of December 31, 2003 and would increase the combined service and interest costs of the postretirement benefit cost by approximately $2.5 million annually.

A one-percent decrease in the health care inflation rate from the assumed rates would decrease the accumulated postretirement benefit obligation by approximately $28.3 million as of December 31, 2003 and would decrease the combined service and interest costs of the postretirement benefit cost by approximately $2.0 million annually.

Qualified Pension Plan Assets

The asset allocations for our qualified pension plans were as follows:

At December 31,	**2003**	2002
Equity securities	**56%**	48%
Debt securities	**32**	36
Other	**12**	16
Total	**100%**	100%

The category "Other" primarily represents investments in financial limited partnerships. Our long-term pension plan investment strategy is to seek an asset mix of 53% equity, 35% fixed income, and 12% other investments. We rebalance our portfolio periodically when the sum of equity and other investments differs from 65% by 5% or more, we change an outside investment advisor, or we make contributions to the trust.

Contributions and Benefit Payments

We plan to contribute a total of $60 million to our qualified pension plans in 2004, even though there is no IRS required minimum contribution. We made a $50 million contribution on January 16, 2004.

Our non-qualified pension plans and our postretirement benefit programs are not funded. We estimate that we will incur approximately $2.7 million in pension benefits for our non-qualified pension plans and approximately $31.0 million for retiree health and life insurance costs during 2004.

Other Postemployment Benefits

We provide the following postemployment benefits:

- health and life insurance benefits to eligible employees determined to be disabled under our Disability Insurance Plan,
- income replacement payments for Nine Mile Point union-represented employees determined to be disabled, and
- income replacement payments for other employees determined to be disabled before November 1995 (payments for employees determined to be disabled after that date are paid by an insurance company, and the cost is paid by employees).

The liability for these benefits totaled $50.6 million as of December 31, 2003 and $49.7 million as of December 31, 2002.

Effective December 31, 1993, we adopted SFAS No. 112. We deferred, as a regulatory asset (see *Note* 6), the postemployment benefit liability attributable to our regulated utility business as of December 31, 1993, consistent with the Maryland PSC's orders for postretirement benefits (described earlier in this Note).

We began to amortize the regulatory asset over 15 years beginning in 1998. The Maryland PSC authorized us to reflect this change in our regulated electric and gas base rates to recover the higher costs in 1998.

We assumed the discount rate for other postemployment benefits to be 5.25% in 2003 and 5.75% in 2002. This assumption impacts the calculation of our other postemployment benefit obligation and periodic cost.

Employee Savings Plan Benefits

We sponsor defined contribution savings plans that are offered to all eligible employees. The savings plans are qualified 401(k) plans under the Internal Revenue Code. In a defined contribution plan, the benefits a participant is to receive result from regular contributions to a participant account. Matching contributions to participant accounts are made under these plans. Matching contributions to these plans were:

- $14.1 million in 2003,
- $13.3 million in 2002, and
- $12.2 million in 2001.

8 Short-Term Borrowings

Our short-term borrowings may include bank loans, commercial paper, and bank lines of credit. Short-term borrowings mature within one year from the date of issuance. We pay commitment fees to banks for providing us lines of credit. When we borrow under the lines of credit, we pay market interest rates.

Constellation Energy

Constellation Energy had committed bank lines of credit under three credit facilities of $1.5 billion at December 31, 2003 for short-term financial needs as follows:

- $447.5 million 364-day revolving credit facility expiring in June 2004,
- $447.5 million three-year revolving credit facility expiring in June 2006, and
- $640.0 million three-year revolving credit facility expiring in June 2005.

We use these facilities to allow issuance of commercial paper and letters of credit primarily for our merchant energy business. These facilities can issue letters of credit up to approximately $1.1 billion. Letters of credit issued under all of our facilities totaled $507.1 million at December 31, 2003 and $338.7 million at December 31, 2002. Constellation Energy had no commercial paper outstanding at December 31, 2003 and 2002.

BGE

BGE had no commercial paper outstanding at December 31, 2003 and 2002.

During 2003, certain credit facilities expired and BGE renewed those facilities. BGE continues to maintain $200.0 million in committed credit facilities, expiring May 2004 through November 2004. BGE can borrow directly from the banks or use the facilities to allow the issuance of commercial paper.

Other Nonregulated Businesses

Our other nonregulated businesses had short-term borrowings outstanding of $9.6 million at December 31, 2003 and $10.5 million at December 31, 2002. The weighted-average effective interest rates for our other nonregulated businesses' short-term borrowings were 3.11% at December 31, 2003 and 3.61% at December 31, 2002.

9 Long-Term Debt and Preference Stock

Long-term Debt

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

Constellation Energy

Constellation Energy issued the following fixed rate notes during 2003:

	Principal	Date Issued	Maturity and Repayment Date	Net Proceeds
		(In millions)		
4.55% Fixed Rate Notes; semi-annual interest payments	$550.0	6/03	6/15	$543.8

We used the net proceeds from this issuance to refinance the debt associated with the High Desert Power Project that we acquired and consolidated beginning June 30, 2003. We discuss the acquisition of the High Desert Power Project in more detail in *Note 15*.

BGE

BGE's First Refunding Mortgage Bonds

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

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

- 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.

In June 2003, BGE announced that it would redeem prior to maturity approximately $98.0 million principal amount outstanding of its 7½% Series due March 1, 2023 First Refunding Mortgage Bonds, which were redeemed on July 21, 2003 at the regular redemption price of 103.32% of principal plus accrued interest from March 1, 2003 to July 20, 2003. BGE also announced that it would redeem prior to maturity approximately $72.3 million principal amount outstanding of its 7½% Series due April 15, 2023 First Refunding Mortgage Bonds, which were redeemed on July 21, 2003 at the regular redemption price of 103.53% of principal plus accrued interest from April 15, 2003 to July 20, 2003.

BGE's Other Long-Term Debt

BGE issued the following fixed rate notes during 2003:

	Principal	Date Issued	Maturity and Repayment Date	Net Proceeds
		(In millions)		
5.20% Fixed Rate Notes; semi-annual interest payments	$200.0	6/03	6/33	$196.8

On July 1, 2000, BGE transferred $278.0 million of tax-exempt debt to our merchant energy business related to the transferred assets. At December 31, 2003, BGE remains contingently liable for the $269.8 million outstanding balance of this debt.

We show the weighted-average interest rates and maturity dates for BGE's fixed-rate medium-term notes outstanding at December 31, 2003 in the following table.

Series	Weighted-Average Interest Rate	Maturity Dates
B	8.62%	2006
D	6.67	2004-2006
E	6.66	2006-2012
G	6.08	2008

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

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

BGE Obligated Mandatorily Redeemable Trust Preferred Securities

In December 2003, BGE redeemed the Deferrable Interest Subordinated Debentures due June 30, 2038 (7.16% debentures), which required the redemption of the $250.0 million Trust Originated Preferred Securities, and dissolved BGE Capital Trust I.

BGE Deferrable Interest Subordinated Debentures

On November 21, 2003, BGE Capital Trust II (BGE Trust II), a Delaware statutory trust established by BGE, issued 10,000,000 Trust Preferred Securities for $250 million ($25 liquidation amount per preferred security) with a distribution rate of 6.20%.

BGE Trust II used the net proceeds from the issuance of common securities to BGE and the Trust Preferred Securities to purchase a series of 6.20% Deferrable Interest Subordinated Debentures due October 15, 2043 (6.20% debentures) from BGE in the aggregate principal amount of $257.7 million with the same terms as the Trust Preferred Securities. BGE Trust II must redeem the Trust Preferred Securities at $25 per preferred security plus accrued but unpaid distributions when the 6.20% debentures are paid at maturity or upon any earlier redemption. BGE has the option to redeem the 6.20% debentures at any time on or after November 21, 2008 or at any time when certain tax or other events occur.

BGE Trust II will use the interest paid on the 6.20% debentures to make distributions on the Trust Preferred Securities. The 6.20% debentures are the only assets of BGE Trust II.

BGE fully and unconditionally guarantees the Trust Preferred Securities based on its various obligations relating to the trust agreement, indentures, 6.20% debentures, and the preferred security guarantee agreement.

For the payment of dividends and in the event of liquidation of BGE, the 6.20% debentures are ranked prior to preference stock and common stock.

At December 31, 2003, we applied the provisions of FIN 46R as it relates to special purpose entities. FIN 46R establishes conditions under which an entity must be consolidated based upon variable interests rather than voting interests. FIN 46R requires us to consolidate variable interest entities for which we are the primary beneficiary. Therefore, at December 31, 2003, we and BGE deconsolidated BGE Trust II because BGE is not its primary beneficiary. As a result, we and BGE removed the Trust Preferred Securities from our and BGE's Consolidated Balance Sheets and from our Consolidated Statements of Capitalization as of December 31, 2003, recorded the $257.7 million of 6.20% Deferrable Interest Subordinated Debentures due to BGE Trust II and recorded our and BGE's $7.7 million equity investment in BGE Trust II in "Other investments" in our and BGE's Consolidated Balance Sheets. We discuss FIN 46R in more detail in *Accounting Standards Issued* section in *Note 1*.

Other Nonregulated Businesses
In November 2002, our other nonregulated businesses entered into a long-term bank facility of $51.7 million in principal with an interest rate of 3.25% fixed rate plus 3 months Eurodollar rate (interest payable quarterly), due December 2008 for net proceeds of $50.4 million. At December 31, 2003, the amount of debt outstanding under this long-term facility was $46.3 million.

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

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

Certain credit facilities of Constellation Energy contain a provision requiring Constellation Energy to maintain a ratio of debt to capitalization equal to or less than 65%. At December 31, 2003, the debt to capitalization ratios as defined in the credit agreements were no greater than 55%.

Certain credit agreements of BGE contain provisions requiring BGE to maintain a ratio of debt to capitalization equal to or less 65%. At December 31, 2003, the debt to capitalization ratio for BGE as defined in these credit agreements was 50%. At December 31, 2003, no amounts were outstanding under these agreements.

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

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

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

Year	Constellation Energy	Nonregulated Business	BGE
		(In millions)	
2004	$ —	$ 12.6	$ 151.4
2005	300.0	12.6	43.2
2006	—	15.0	439.5
2007	600.0	17.1	122.5
2008	—	37.0	296.0
Thereafter	2,450.0	294.9	600.8
Total long-term debt at December 31, 2003	$3,350.0	$389.2	$1,653.4

At December 31, 2003, we had long-term loans totaling $387.0 million that mature after 2003 which contain certain put options under which lenders could potentially require us to repay the debt prior to maturity. At December 31, 2003, $179.2 million is classified as current portion of long-term debt as a result of these provisions.

Weighted-Average Interest Rates for Variable Rate Debt
Our weighted-average interest rates for variable rate debt were:

At December 31,	2003	2002
Nonregulated Businesses (including Constellation Energy)		
Loans under credit agreements	3.98%	4.42%
Tax-exempt debt transferred from BGE	1.40	1.97
Other tax-exempt debt	—	1.49
BGE		
Remarketed floating rate series mortgage bonds	1.29%	1.91%

Preference Stock
Each series of BGE preference stock has no voting power, except for the following:

- the preference stock has one vote per share on any charter amendment which would create or authorize any shares of stock ranking prior to or on a parity with the preference stock as to either dividends or distribution of assets, or which would substantially adversely affect the contract rights, as expressly set forth in BGE's charter, of the preference stock, each of which requires the affirmative vote of two-thirds of all the shares of preference stock outstanding; and
- whenever BGE fails to pay full dividends on the preference stock and such failure continues for one year, the preference stock shall have one vote per share on all matters, until and unless such dividends shall have been paid in full. Upon liquidation, the holders of the preference stock of each series outstanding are entitled to receive the par amount of their shares and an amount equal to the unpaid accrued dividends.

10 Taxes

The components of income tax expense are as follows:

Year Ended December 31,	2003	2002	2001
	(Dollar amounts in millions)		
Income Taxes			
Current			
Federal	$134.0	$145.0	$ 45.5
State	33.6	24.2	27.0
Current taxes charged to expense	167.6	169.2	72.5
Deferred			
Federal	93.2	131.2	(22.4)
State	16.0	17.1	(4.1)
Deferred taxes charged to expense	109.2	148.3	(26.5)
Investment tax credit adjustments	(7.3)	(7.9)	(8.1)
Income taxes per Consolidated Statements of Income	$269.5	$309.6	$ 37.9

Total income taxes are different from the amount that would be computed by applying the statutory Federal income tax rate of 35% to book income before income taxes as follows:

Reconciliation of Income Taxes Computed at Statutory Federal Rate to Total Income Taxes			
Income before income taxes (excluding BGE preference stock dividends)	$758.4	$848.4	$133.5
Statutory federal income tax rate	35%	35%	35%
Income taxes computed at statutory federal rate	265.4	296.9	46.7
Increases (decreases) in income taxes due to			
Depreciation differences not normalized on regulated activities	4.1	4.8	5.6
Amortization of deferred investment tax credits	(7.3)	(7.9)	(8.1)
Synthetic fuel tax credits flowed through to income	(35.0)	(20.7)	(13.4)
State income taxes, net of federal income tax benefit	34.1	31.4	13.5
Other	8.2	5.1	(6.4)
Total income taxes	$269.5	$309.6	$ 37.9
Effective income tax rate	35.5%	36.5%	28.4%

The major components of our net deferred income tax liability are as follows:

At December 31,	2003	2002
	(In millions)	
Deferred Income Taxes		
Deferred tax liabilities		
Net property, plant and equipment	$1,295.8	$1,242.4
Asset retirement obligation, net	94.5	—
Regulatory assets, net	105.7	110.7
Mark-to-market energy assets and liabilities, net	88.6	285.5
Financial investments and hedging instruments	33.8	3.2
Other	132.1	130.3
Total deferred tax liabilities	1,750.5	1,772.1
Deferred tax assets		
Accrued pension and post-employment benefit costs	183.3	211.8
Deferred investment tax credits	27.4	30.0
Nuclear decommissioning liability	—	34.4
Reduction of investments	40.4	53.8
Other	115.0	111.4
Total deferred tax assets	366.1	441.4
Deferred tax liability, net	$1,384.4	$1,330.7

10 Taxes

The components of income tax expense are as follows:

Year Ended December 31,	**2003**	2002	2001
		(Dollar amounts in millions)	
Income Taxes			
Current			
Federal	**$134.0**	$145.0	$ 45.5
State	**33.6**	24.2	27.0
Current taxes charged to expense	**167.6**	169.2	72.5
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Federal	**93.2**	131.2	(22.4)
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Deferred taxes charged to expense	**109.2**	148.3	(26.5)
Investment tax credit adjustments	**(7.3)**	(7.9)	(8.1)
Income taxes per Consolidated Statements of Income	**$269.5**	$309.6	$ 37.9

Total income taxes are different from the amount that would be computed by applying the statutory Federal income tax rate of 35% to book income before income taxes as follows:

Reconciliation of Income Taxes Computed at Statutory Federal Rate to Total Income Taxes			
Income before income taxes (excluding BGE preference stock dividends)	**$758.4**	$848.4	$133.5
Statutory federal income tax rate	**35%**	35%	35%
Income taxes computed at statutory federal rate	**265.4**	296.9	46.7
Increases (decreases) in income taxes due to			
Depreciation differences not normalized on regulated activities	**4.1**	4.8	5.6
Amortization of deferred investment tax credits	**(7.3)**	(7.9)	(8.1)
Synthetic fuel tax credits flowed through to income	**(35.0)**	(20.7)	(13.4)
State income taxes, net of federal income tax benefit	**34.1**	31.4	13.5
Other	**8.2**	5.1	(6.4)
Total income taxes	**$269.5**	$309.6	$ 37.9
Effective income tax rate	**35.5%**	36.5%	28.4%

The major components of our net deferred income tax liability are as follows:

At December 31,	**2003**	2002
	(In millions)	
Deferred Income Taxes		
Deferred tax liabilities		
Net property, plant and equipment	**$1,295.8**	$1,242.4
Asset retirement obligation, net	**94.5**	—
Regulatory assets, net	**105.7**	110.7
Mark-to-market energy assets and liabilities, net	**88.6**	285.5
Financial investments and hedging instruments	**33.8**	3.2
Other	**132.1**	130.3
Total deferred tax liabilities	**1,750.5**	1,772.1
Deferred tax assets		
Accrued pension and post-employment benefit costs	**183.3**	211.8
Deferred investment tax credits	**27.4**	30.0
Nuclear decommissioning liability	**—**	34.4
Reduction of investments	**40.4**	53.8
Other	**115.0**	111.4
Total deferred tax assets	**366.1**	441.4
Deferred tax liability, net	**$1,384.4**	$1,330.7

Synthetic Fuel Tax Credits

We have investments in facilities that manufacture solid synthetic fuel produced from coal as defined under Section 29 of the Internal Revenue Code for which we claim tax credits on our Federal income tax return. We recognize the tax benefit of these credits in our Consolidated Statements of Income when we believe it is highly probable that the credits will be sustained. The synthetic fuel process involves combining coal material with a chemical reagent to create a significant chemical change. A taxpayer may request a private letter ruling from the IRS to support its position that the synthetic fuel produced undergoes a significant chemical change and thus qualifies for Section 29 credits.

As of December 31, 2003, we have recognized cumulative tax benefits associated with Section 29 credits of $78.0 million, of which $35.0 million was recognized during the year ended December 31, 2003. These credits relate to our minority ownership in four synthetic fuel facilities located in Ohio, Virginia and West Virginia. These facilities have received private letter rulings from the IRS. In January 2004, the IRS concluded its examination of the partnership that owns these facilities for the tax years 1998 through 2001 and the IRS did not disallow any of the previously recognized synthetic fuel credits. We are awaiting final written notice of the resolution of the examination from the IRS.

In 2003, we purchased 99% ownership in a South Carolina facility that produces synthetic fuel. On January 12, 2004, we submitted our request for a private letter ruling to the IRS for our South Carolina facility. Our South Carolina facility is using the same synthetic fuel process that was utilized by the previous owner, which had received a private letter ruling. As of the date of this report, we have not yet received our private letter ruling from the IRS for our South Carolina facility.

Since we may not rely upon a private letter ruling issued by the IRS to another taxpayer, we have not recognized the tax benefit of approximately $36 million for these credits in our Consolidated Statements of Income during 2003. We have the option under the amended purchase agreement for this facility to terminate our participation, without penalty, by April 5, 2004. We are currently evaluating our strategy regarding this facility and have not decided whether we will end our participation.

While we believe the production and sale of synthetic fuel from all of our synthetic fuel facilities meet the conditions to qualify for tax credits under Section 29 of the IRS Code, we cannot predict the timing or outcome of any future challenge by the IRS, legislative or regulatory action, or the ultimate impact of such events on the Section 29 credits that we have claimed to date or expect to claim in the future, but the impact could be material to our financial results.

11 Leases

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

Outgoing Lease Payments

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

Lease expense was:

- $22.7 million in 2003,
- $19.4 million in 2002, and
- $11.7 million in 2001.

At December 31, 2003, we owed future minimum payments for long-term, noncancelable, operating leases as follows:

Year	*(In millions)*
2004	$ 22.1
2005	20.0
2006	18.8
2007	15.2
2008	11.4
Thereafter	117.2
Total future minimum lease payments	$204.7

12 Commitments, Guarantees, and Contingencies

Commitments

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

- purchase of electric generating capacity and energy,
- procurement and delivery of fuels, and
- long-term service agreements, capital for construction programs and other.

Our merchant energy business enters into various long-term contracts for the procurement and delivery of fuels to supply our generating plant requirements. In most cases, our contracts contain provisions for price escalations, minimum purchase levels, and other financial commitments. These contracts expire in various years between 2004 and 2013. In addition, our merchant energy business enters into long-term contracts for the capacity and transmission rights for the delivery of energy to meet our physical obligations to our customers. These contracts expire in various years between 2004 and 2018.

Our merchant energy business also has committed to long-term service agreements and other purchase commitments for our plants.

Our regulated gas business enters into various long-term contracts for the procurement, transportation, and storage of gas. Our regulated gas business has gas transportation and storage contracts that expire between 2005 and 2020. These contracts are recoverable under BGE's gas cost adjustment clause discussed in *Note 1* and therefore are excluded from the table below.

Our other nonregulated business has committed to gas purchases, as well as to contribute additional capital for construction programs and joint ventures in which they have an interest.

Corporately, we have committed to long-term service agreements and other obligations related to our information technology systems.

At December 31, 2003, we estimate our future obligations to be as follows:

	Payments				
	2004	2005-2006	2007-2008	Thereafter	Total
	(In millions)				
Merchant Energy:					
Purchased capacity and energy	$1,318.8	$1,105.7	$267.3	$188.9	$2,880.7
Fuel and transportation	549.2	424.6	63.9	52.8	1,090.5
Long-term service agreements, capital, and other	28.1	27.8	37.3	217.1	310.3
Total merchant energy	1,896.1	1,558.1	368.5	458.8	4,281.5
Corporate and Other:					
Fuel and transportation	2.6	—	—	—	2.6
Long-term service agreements, capital, and other	48.6	21.0	3.4	1.8	74.8
Total corporate and other	51.2	21.0	3.4	1.8	77.4
Total future obligations	$1,947.3	$1,579.1	$371.9	$460.6	$4,358.9

Long-Term Power Sales Contracts

We enter into long-term power sales contracts in connection with our load-serving activities. We also enter into long-term power sales contracts associated with certain of our power plants. Our load-serving power sales contracts extend for terms through 2012 and provide for the sale of full requirements energy to electricity distribution utilities and certain retail customers. Our power sales contracts associated with our power plants extend for terms into 2011 and provide for the sale of all or a portion of the actual output of certain of our power plants. All long-term contracts were executed at pricing that approximated market rates, including profit margin, at the time of execution.

Sale of Receivables

BGE Home Products & Services has an agreement to sell on an ongoing basis an undivided interest in a designated pool of customer receivables. Under the agreement, BGE Home Products & Services can sell up to a total of $50 million. Under the terms of the agreement, the buyer of the receivables has limited recourse against BGE Home Products & Services. BGE Home Products & Services recorded reserves for credit losses. At December 31, 2003, BGE Home Products & Services sold $37.8 million of receivables under the agreement.

Planned Acquisition

On November 25, 2003 we announced an agreement to acquire the R.E. Ginna Nuclear Power Plant located north of Rochester, New York from Rochester Gas & Electric (RG&E). Upon closing the acquisition of this 495 MW facility, we will own and operate three nuclear power stations. The purchase price for the Ginna facility is $401 million, excluding approximately $22 million for purchased nuclear fuel. RG&E will transfer approximately $202 million in decommissioning funds at the time of closing. We believe this transfer will be sufficient to meet the decommissioning requirements of the facility.

The transaction, which is contingent upon license extension and other regulatory approvals, includes a long-term unit contingent power purchase agreement where we will sell 90% of the plant's output and capacity to RG&E for 10 years at an average price of $44.00 per MWH. The remaining 10% of the plant's output will be managed by our wholesale marketing and risk management operation and be sold into the wholesale market.

Guarantees

The terms of our guarantees are as follows:

	Payments/Expiration				
	2004	2005-2006	2007-2008	Thereafter	Total
			(In millions)		
Competitive Supply	$3,166.0	$265.6	$162.0	$381.8	$3,975.4
Other	16.1	9.9	10.6	508.6	545.2
Total Guarantees	$3,182.1	$275.5	$172.6	$890.4	$4,520.6

At December 31, 2003, Constellation Energy had a total of $4,520.6 million guarantees outstanding related to loans, credit facilities, and contractual performance of certain of its subsidiaries as described below. These guarantees do not represent our incremental obligations and we do not expect to fund the full amount under these guarantees.

- Constellation Energy guaranteed $3,975.4 million on behalf of our subsidiaries for competitive supply activities. These guarantees are put into place in order to allow our subsidiaries the flexibility needed to conduct business with counterparties without having to post substantial cash collateral. While the face amount of these guarantees is $3,975.4 million, our calculated fair value of obligations covered by these guarantees was $902.2 million at December 31, 2003. If the parent company was required to fund subsidiary obligations, the total amount at current market price is $902.2 million. The recorded fair value of obligations in our Consolidated Balance Sheets for these guarantees was $689.3 million at December 31, 2003.
- Constellation Energy guaranteed $209.6 million primarily on behalf of Nine Mile Point related to nuclear decommissioning.
- Constellation Energy guaranteed $34.4 million on behalf of our other nonregulated businesses primarily for loans and performance bonds of which $25.6 million was recorded in our Consolidated Balance Sheets at December 31, 2003.
- Our merchant energy business guaranteed $21.1 million for loans and other performance guarantees related to certain power projects in which we have an investment.
- Our other nonregulated business guaranteed $16.8 million for performance bonds.
- BGE guaranteed two-thirds of certain debt of Safe Harbor Water Power Corporation, an unconsolidated investment. At December 31, 2003, Safe Harbor Water Power Corporation had outstanding debt of $20.0 million. The maximum amount of BGE's guarantee is $13.3 million.
- BGE guaranteed the Trust Preferred Securities of $250.0 million of BGE Trust II, an unconsolidated investment, as discussed in *Note 9*.

The total fair value of the obligations for our guarantees recorded in our Consolidated Balance Sheets was $714.9 million and not the $4.5 billion of total guarantees. We assess the risk of loss from these guarantees to be minimal.

Environmental Matters

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

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

The development (involving site selection, environmental assessments, and permitting), construction, acquisition, and operation of electric generating and distribution facilities are subject to extensive federal, state, and local environmental and land use laws and regulations. From the beginning phases of siting and developing, to the ongoing operation of existing or new electric generating and distribution facilities, our activities involve compliance with diverse laws and regulations that address emissions and impacts to air and water, special, protected and cultural resources (such as wetlands, endangered species, and archeological/historical resources), chemical, and waste handling and noise impacts.

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

Our capital expenditures (excluding allowance for funds used during construction) were approximately $260 million during the five-year period 1999-2003 to comply with existing environmental standards and regulations.

Clean Air Act

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

On October 27, 1998, the Environmental Protection Agency (EPA) issued a rule requiring 22 Eastern states and the District of Columbia to reduce emissions of NOx. The EPA rule requires states to implement controls sufficient to meet their NOx budget by May 30, 2004. However, the Northeast states decided to require compliance in 2003. Coal-fired power plants are a principal target of NOx reductions under this initiative.

Many of our generation facilities are subject to NOx reduction requirements under the EPA rule, including those located in Maryland and Pennsylvania. At the Brandon Shores and Wagner facilities, we installed emission reduction equipment for our coal-fired units to meet Maryland regulations issued pursuant to the EPA's rule. The owners of the Keystone plant in Pennsylvania completed the installation of emissions reduction equipment by July 2003 to meet Pennsylvania regulations issued pursuant to the EPA's rule. Our total cost of the emissions reduction equipment at the Keystone plant was approximately $37 million.

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

We may be impacted by the EPA's designation of certain areas as severe ozone nonattainment areas. These are areas where air pollution levels severely exceed national air quality standards. We own several generating facilities in severe ozone nonattainment areas in Maryland and California. The Clean Air Act requires states to assess fees against every major stationary source of NOx and volatile organic chemicals in severe ozone nonattainment areas if national air quality standards are not achieved by a specified deadline. If implemented, the fee would be assessed based on the magnitude of a source's emissions as compared to its emissions when the area failed to meet the deadline. The exact method of computing these fees has not been established and will depend in part on state implementing regulations that have not been finalized.

The current deadline for most severe nonattainment areas is 2005, including those in which our generating facilities are located. Assessment of fees would commence in 2006 if the current effective date is maintained. However, there is significant uncertainty regarding the date when fees would be assessed in light of pending federal legislation and anticipated EPA rulemaking. Currently, we are unable to estimate the ultimate timing or financial impact of the standard in light of the uncertainty surrounding its effective date and the methodology that will be used in calculating the fees.

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

Based on the level of emissions control that the EPA and states are seeking in these new source review enforcement actions, we believe that material additional costs and penalties could be incurred, and planned capital expenditures could be accelerated, if the EPA was successful in any future actions regarding our facilities.

On October 27, 2003, the EPA's new source review rule on routine maintenance was published in the Federal Register. The new regulations would establish an equipment replacement cost threshold for determining when major new source review requirements are triggered. Plant owners may spend up to 20% of the replacement value of a generation unit on certain improvements each year without triggering requirements for new pollution controls. Parties had until December 26, 2003, the effective date of the rule, to appeal the agency's decision in court. An appeal was filed with the United States Court of Appeals. The effective date of the rule has been delayed pending review.

The Clean Air Act required the EPA to evaluate the public health impacts of emissions of mercury, a hazardous air pollutant, from coal-fired plants. The EPA decided to control mercury emissions from coal-fired plants. On December 15, 2003, the EPA proposed two alternatives for controlling mercury emissions from generating facilities. The EPA may require the installation of mercury reduction equipment. Alternatively, the EPA may revise standards to allow for the purchase of allowances. Compliance could be required as soon as 2007, or by 2010 depending on which alternative is selected. We believe final regulations could be issued in 2004 and could affect all oil-fired and coal-fired boilers. The cost of compliance with the final regulations could be material.

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

Clean Water Act

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

In April 2002, the EPA proposed rules under the Clean Water Act that require that cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts. In February 2004, the proposed rules were finalized. The final rules require the installation of additional intake screens or other protective measures, as well as extensive site-specific study and monitoring requirements. We are currently reviewing the final rules and their potential impact to us. Our compliance costs associated with the final rules could be material.

Under current provisions of the Clean Water Act, existing permits must be renewed at least every five years, at which time permit limits come under extensive review and can be modified to account for more stringent regulations. In addition, the permits can be modified at any time. Changes to the water discharge permits of our coal or other fuel suppliers due to federal or state initiatives may increase the cost of fuel, which in turn could have a significant impact on our operations.

Waste Disposal

The EPA and several state agencies have notified us that we are considered a potentially responsible party with respect to the clean-up of certain environmentally contaminated sites owned and operated by others. We cannot estimate the clean-up costs for all of these sites.

However, based on a Record of Decision (ROD) issued by the EPA in 1997, we can estimate that BGE's current 15.47% share of the reasonably possible clean-up costs at one of these sites, Metal Bank of America, a metal reclaimer in Philadelphia, could be as much as $1.3 million higher than amounts we believe are probable and have recorded as a liability in our Consolidated Balance Sheets. There has been no significant regulatory activity with respect to actual site remediation since the EPA's ROD in 1997. EPA and the potentially responsible parties, including BGE, are currently pursuing claims against Metal Bank of America for an equitable share of expected site remediation costs.

In 1999, the EPA proposed to add the 68th Street Dump in Baltimore, Maryland to the Comprehensive Environmental Response, Compensation and Liability Act ("Superfund") National Priorities List ("NPL"), which is its list of sites targeted for clean-up and enforcement, and sent a general notice letter to BGE and 19 other parties identifying them as potentially liable parties at the 68th Street Dump site. In April 2003, EPA re-proposed the 68th Street site to the NPL, but decided not to include the site in its September 2003 update. BGE and other potentially responsible parties are pursuing alternatives to NPL listing for the site, but at this stage, it is not possible to predict the outcome of those discussions, the clean-up cost of the site, or BGE's share of the liability. However, the costs could have a material effect on our, or BGE's, financial results.

In late December 1996, BGE signed a consent order with the Maryland Department of the Environment that required BGE to implement remedial action plans for contamination at and around the Spring Gardens site, located in Baltimore, Maryland. The Spring Gardens site was once used to manufacture gas from coal and oil. Based on the remedial action plans, the costs BGE considers to be probable to remedy the contamination are estimated to total $47 million. BGE recorded these costs as a liability in its Consolidated Balance Sheets and deferred these costs, net of accumulated amortization and amounts it recovered from insurance companies, as a regulatory asset. Because of the results of studies at this site, it is reasonably possible that additional costs could exceed the amount BGE recognized by approximately $14 million. Through December 31, 2003, BGE spent approximately $39 million for remediation at this site. BGE also investigated other small sites where gas was manufactured in the past. We do not expect the clean-up costs of the remaining smaller sites to have a material effect on our financial results.

The EPA issued its ROD for the Kane and Lombard Drum site located in Baltimore, Maryland on September 30, 2003. The ROD specifies the clean-up plan for the site, consisting of enhanced reductive dechlorination, a soil management plan, and institutional controls. The ROD was consistent with the proposed remedy the EPA released in December 2002. We expect the EPA to approach the potentially responsible parties regarding implementation of the plan in 2004. The total clean-up costs are estimated to be $7.3 million. We estimate our current share of site-related costs to be 11.1%. Our share of these future costs has not been determined and it may vary from the current estimate. In December 2002, we recorded a liability in our Consolidated Balance Sheets for our share of the clean-up costs that we believe is probable.

Litigation

In the normal course of business, we are involved in various legal proceedings. We discuss the significant matters below.

California

Baldwin Associates, Inc. v. Gray Davis, Governor of California and 22 other defendants (including Constellation Power Development, Inc., a subsidiary of Constellation Power, Inc.)—This class action lawsuit was filed on October 5, 2001 in the Superior Court, County of San Francisco. The action seeks damages of $43 billion, recession and reformation of approximately 38 long-term power purchase contracts, and an injunction against improper spending by the state of California.

Constellation Power Development, Inc. is named as a defendant but does not have a power purchase agreement with the State of California. However, our High Desert Power Project does have a power purchase agreement with the California Department of Water Resources. In 2002, the court issued an order to the plaintiff asking that he show cause why he had not yet served the defendants. In April 2002, a second show cause order was issued. After numerous postponements, a hearing is now scheduled on April 16, 2004 on that order.

James M. Millar v. Allegheny Energy Supply, Constellation Power Source, Inc., High Desert Power Project, LLC, et al—On December 19, 2003, plaintiffs filed an amended complaint in Superior Court of California, County of San Francisco, naming for the first time, Constellation Power Source, Inc. (CPS) and High Desert Power Project, LLC (High Desert), two of our subsidiaries, as additional defendants. The complaint is a putative class action on behalf of California electricity consumers and alleges that the defendant power suppliers, including CPS and High Desert, violated California's Unfair Competition Law in connection with certain long-term power contracts that the defendants negotiated with the California Department of Water Resources in 2001 and 2002. Notwithstanding the amended long-term power contracts and the releases and settlement agreements negotiated at the time of such amendments, the plaintiff seeks to have the Court certify the case as a class action and to order the repayment of any monies that were acquired by the defendants under the long-term contracts or the amended long-term contracts by means of unfair competition in violation of California law. On February 6, 2004, the case was removed to the United States District Court for the Northern District of California. We believe that we have meritorious defenses to this action and intend to defend against it vigorously. However, we can not predict the timing, or outcome, of this case, or its possible effect on our results.

NewEnergy

Constellation NewEnergy, Inc. v. PowerWeb Technology, Inc.—Prior to our acquisition, NewEnergy filed a complaint on May 9, 2002 in the U.S. District Court of Eastern Pennsylvania seeking approximately $100,000 in direct damages relating to a contract previously entered into with PowerWeb. PowerWeb Technology has counter-claimed seeking $100 million in damages against NewEnergy alleging a breach of a non-disclosure agreement by misappropriation of trade secrets and tortious interference claims. Discovery is ongoing in the matter. We cannot predict the timing, or outcome, of the action or its possible effect on our financial results. However, based on the information available to Constellation Energy at this time, we believe NewEnergy has meritorious defenses to the PowerWeb Technology counterclaim.

Mercury Poisoning

Beginning in September 2002, BGE, Constellation Energy, and several other defendants have been involved in numerous actions alleging mercury poisoning from several sources, including coal plants formerly owned by BGE. The plants are now owned by a subsidiary of Constellation Energy. In addition to BGE and Constellation Energy, approximately 11 other defendants, consisting of pharmaceutical companies, manufacturers of vaccines, and manufacturers of Thimerosal have been sued. Approximately 60 cases have been filed to date in the Circuit Court for Baltimore City, with each case seeking $90 million in damages from the group of defendants.

In a ruling applicable to all but several of the cases, the Circuit Court for Baltimore City dismissed with prejudice all claims against BGE and Constellation Energy and entered a stay of the proceedings as they relate to other defendants. The several cases that were not dismissed were filed subsequent to the ruling by the Circuit Court. Plaintiffs' may attempt to pursue appeals of the rulings in favor of BGE and Constellation Energy once the cases are finally concluded as to all defendants. At this time no discovery has occurred. We believe that we have meritorious defenses to all of the cases and intend to defend the action vigorously. However, we cannot predict the timing or outcome of these cases, or their possible effect on our, or BGE's, financial results.

Employment Discrimination

Miller, et. al v. Baltimore Gas and Electric Company, et al.—This action was filed on September 20, 2000 in the U.S. District Court for the District of Maryland. Besides BGE, Constellation Energy Group, Constellation Nuclear, and Calvert Cliffs Nuclear Power Plant are also named defendants. The action seeks class certification for approximately 150 past and present employees and alleges racial discrimination at Calvert Cliffs Nuclear Power Plant. The amount of damages is unspecified, however the plaintiffs seek back and front pay, along with compensatory and punitive damages. The Court scheduled a briefing process for the motion to certify the case as a class action suit. The briefing process has concluded and oral argument on the class certification motion is scheduled for April 16, 2004. We do not believe class certification is appropriate and we further believe that we have meritorious defenses to the underlying claims and intend to defend the action vigorously. However, we cannot predict the timing, or outcome, of the action or its possible effect on our, or BGE's, financial results.

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

The first type is direct claims by individuals exposed to asbestos. BGE is involved in these claims with approximately 70 other defendants. Approximately 570 individuals that were never employees of BGE each claim $6 million in damages ($2 million compensatory and $4 million punitive). These claims are currently pending in state courts in Maryland and Pennsylvania. BGE does not know the specific facts necessary to estimate its potential liability for these claims. The specific facts BGE does not know include:

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

To date, 259 asbestos cases were dismissed or resolved for amounts that were not significant. Approximately 155 cases are scheduled for trial by the end of 2004.

The second type is claims by one manufacturer—Pittsburgh Corning Corp. (PCC)—against BGE and approximately eight others, as third-party defendants. On April 17, 2000, PCC declared bankruptcy.

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

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

Until the relevant facts for both types of claims are determined, we are unable to estimate what our, or BGE's, liability might be. Although insurance and hold harmless agreements from contractors who employed the plaintiffs may cover a portion of any awards in the actions, the potential effect on our, or BGE's, financial results could be material.

Other
McCray, et. al. v. Baltimore Gas and Electric Company—On June 10, 2002, a suit was filed in the Circuit Court of Baltimore City, Maryland seeking compensatory and punitive damages from BGE as a result of a fire in a home that caused five fatalities. This case was settled for an immaterial amount.

Storage of Spent Nuclear Fuel
The Nuclear Waste Policy Act of 1982 (NWPA) required the federal government through the Department of Energy (DOE), to develop a repository for, and disposal of, spent nuclear fuel and high-level radioactive waste. The NWPA and our contracts with the DOE required the DOE to begin taking possession of spent nuclear fuel generated by nuclear generating units no later than January 31, 1998. The DOE has stated that it will not meet that obligation until 2010 at the earliest. This delay has required that we undertake additional actions related to on-site fuel storage at Calvert Cliffs and Nine Mile Point, including the installation of on-site dry fuel storage capacity at Calvert Cliffs. In January 2004, we filed a complaint against the federal government in the United States Court of Federal Claims seeking to recover damages caused by the DOE's failure to meet its contractual obligation to begin disposing of spent nuclear fuel by January 31, 1998.

Nuclear Insurance
We maintain nuclear insurance coverage for Calvert Cliffs and Nine Mile Point in four program areas: liability, worker radiation, property, and accidental outage. These policies contain certain industry standard exclusions, including, but not limited to, ordinary wear and tear, and war.

In November 2002, the President signed into law the Terrorism Risk Insurance Act ("TRIA") of 2002. Under the TRIA, property and casualty insurance companies are required to offer insurance for losses resulting from Certified acts of terrorism. Certified acts of terrorism are determined by the Secretary of State and Attorney General and primarily are based upon the occurrence of significant acts of international terrorism. Our nuclear property and accidental outage insurance programs, as discussed later in this section, provide coverage for Certified acts of terrorism.

Losses resulting from non-certified acts of terrorism are covered as a common occurrence, meaning that if non-certified terrorist acts occur against one or more commercial nuclear power plants insured by our insurance company within a 12-month period, they would be treated as one event and the owners of the plants would share one full limit of liability (currently $3.24 billion).

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

Nuclear Liability Insurance
Pursuant to the Price-Anderson Act, we are required to insure against public liability claims resulting from nuclear incidents to the full limit of public liability. This limit of liability consists of the maximum available commercial insurance of $300 million and mandatory participation in an industry-wide retrospective premium assessment program. The retrospective premium assessment has been increased to $100.6 million per reactor, increasing the total amount of insurance for public liability to approximately $10.8 billion. Under the retrospective assessment program, we can be assessed up to $402.4 million per incident at any commercial reactor in the country, payable at no more

than $40 million per incident per year. This assessment also applies in excess of our worker radiation claims insurance and is subject to inflation and state premium taxes. In addition, the U.S. Congress could impose additional revenue-raising measures to pay claims.

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

- Nuclear worker claims reported on or after January 1, 1998 are covered by a new insurance policy with an annual industry aggregate limit of $300 million for radiation injury claims against all those insured by this policy.
- All nuclear worker claims reported prior to January 1, 1998 are still covered by the old policy. Insureds under the old policies, with no current operations, are not required to purchase the new policy described above, and may still make claims against the old policies through 2007. If radiation injury claims under these old policies exceed the policy reserves, all policyholders could be retroactively assessed, with our share being up to $6.3 million.

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

Nuclear Property Insurance
Our policies provide $500 million in primary and an additional $2.25 billion in excess coverage for property damage, decontamination, and premature decommissioning liability for Calvert Cliffs or Nine Mile Point. This coverage currently is purchased through an industry mutual insurance company. If accidents at plants insured by the mutual insurance company cause a shortfall of funds, all policyholders could be assessed, with our share being up to $68.6 million.

Accidental Nuclear Outage Insurance
Our policies provide indemnification on a weekly basis for losses resulting from an accidental outage of a nuclear unit. Coverage begins after a 12-week deductible period and continues at 100% of the weekly indemnity limit for 52 weeks and then 80% of the weekly indemnity limit for the next 110 weeks. Our coverage is up to $490.0 million per unit at Calvert Cliffs, $420.0 million for Unit 1 of Nine Mile Point, and $412.6 million for Unit 2 of Nine Mile Point. This amount can be reduced by up to $98.0 million per unit at Calvert Cliffs and $82.5 million for Nine Mile Point if an outage of more than one unit is caused by a single insured physical damage loss.

Non-Nuclear Property Insurance
Our conventional property insurance provides coverage of $1.0 billion per occurrence for Certified acts of terrorism as defined under the Terrorism Risk Insurance Act of 2002. Certified acts of terrorism are determined by the Secretary of State and Attorney General of the United States and primarily are based upon the occurrence of significant acts of international terrorism. Our conventional property insurance program also provides coverage of $333.0 million per occurrence (subject to a $333.0 million annual aggregate) for losses resulting from non-certified acts of terrorism. If a terrorist act occurs at any of our facilities, it could have a significant adverse impact on our financial results.

California Power Purchase Agreements
Our merchant energy business has $251.8 million invested in operating power projects of which our ownership percentage represents 140 megawatts of electricity that are sold to Pacific Gas & Electric (PGE) and to Southern California Edison (SCE) in California under power purchase agreements.

As a result of ongoing litigation before the Federal Energy Regulatory Commission (FERC) regarding sales into the spot markets of the California Independent System Operator (ISO) and Power Exchange (PX), we currently estimate that we may be required to pay refunds of between $2 million and $6 million for transactions that we entered into with these entities for the period between October 2000 and June 2001. However, we cannot determine the actual amount we could be required to pay because litigation is ongoing and new events could occur that may cause the actual amount, if any, to be materially different from our estimate.

13 Hedging Activities and Fair Value of Financial Instruments

SFAS No. 133 Hedging Activities

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

Interest Rates

We use interest rate swaps to manage our interest rate exposures associated with new debt issuances. These swaps are designated as cash-flow hedges under SFAS No. 133 in anticipation of planned financing transactions as discussed in *Note 1*. The notional amounts of the contracts do not represent amounts that are exchanged by the parties and are not a measure of our exposure to market or credit risks. The notional amounts are used in the determination of the cash settlements under the contracts.

During 2003, we entered into various forward starting interest rate swaps to manage our interest rate exposure for the issuances of $550.0 million of Constellation Energy debt and $200.0 million of BGE debt. All of these swap contracts expired in the second quarter of 2003 resulting in a pre-tax net loss of $8.7 million that was recorded in "Accumulated other comprehensive income" in our Consolidated Balance Sheets. Of this amount, BGE recorded a pre-tax gain of $1.2 million in "Accumulated other comprehensive income" in its Consolidated Balance Sheets.

At December 31, 2003, we have net unrealized pre-tax gains of $21.2 million on interest rate cash-flow hedges recorded in "Accumulated other comprehensive income." We expect to reclassify $2.9 million of pre-tax net gains on these cash-flow hedges from "Accumulated other comprehensive income" into "Interest expense" during the next twelve months.

Commodity Prices

Our wholesale marketing and risk management operation uses a variety of derivative and non-derivative instruments to manage the commodity price risk of our competitive supply activities and our electric generation facilities, including power sales, fuel and energy purchases, gas purchased for resale, emission credits, weather risk, and the market risk of outages. In order to manage these risks, we may enter into fixed-price derivative or non-derivative contracts to hedge the variability in future cash flows from forecasted sales of energy and purchases of fuel and energy, including:

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

The objectives for entering into such hedges include:

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

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

At December 31, 2003, our merchant energy business had designated certain fixed-price forward contracts as cash-flow hedges of forecasted sales of energy and forecasted purchases of fuel and energy for the years 2004 through 2010 under SFAS No. 133.

At December 31, 2003, our merchant energy business has net unrealized pre-tax gains of $16.1 million on these hedges recorded in "Accumulated other comprehensive income." We expect to reclassify $104.1 million of net pre-tax gains on cash-flow hedges from "Accumulated other comprehensive income" into earnings during the next twelve months based on the market prices at December 31, 2003. However, the actual amount reclassified into earnings could vary from the amounts recorded at December 31, 2003 due to future changes in market prices. In 2003, we recognized $7.0 million of pre-tax gains in earnings related to hedge ineffectiveness.

Regulated Gas Business

BGE uses basis swaps in the winter months (November through March) to hedge its price risk associated with natural gas purchases under its market-based rates incentive mechanism. BGE also uses fixed-to-floating and floating-to-fixed swaps to hedge its price risk associated with its off-system gas sales. The fixed portion represents a specific dollar amount that BGE will pay or receive, and the floating portion represents a fluctuating amount based on a published index that BGE will receive or pay. BGE'S regulated gas business internal guidelines do not permit the use of swap agreements for any purpose other than to hedge price risk.

Fair Value of Financial Instruments

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

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

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

At December 31,	2003		2002	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In millions)			
Investments and other assets for which it is:				
Practicable to estimate fair value	$ 876.2	$ 876.2	$ 713.7	$ 713.7
Not practicable to estimate fair value	22.5	N/A	24.2	N/A
Fixed-rate long-term debt	5,069.4	5,723.5	4,713.9	5,018.8
Variable-rate long-term debt	323.2	323.2	335.9	335.9

It was not practicable to estimate the fair value of investments held by our nonregulated businesses in several financial partnerships that invest in nonpublic debt and equity securities. This is because the timing and amount of cash flows from these investments are difficult to predict. We report these investments at their original cost in our Consolidated Balance Sheets.

The investments in financial partnerships totaled $22.5 million at December 31, 2003, representing ownership interests up to 10% and $24.2 million at December 31, 2002, representing ownership interests up to 10%. The total assets of all of these partnerships totaled $4.0 billion at December 31, 2002 (which is the latest information available).

14 Stock-Based Compensation

Under our long-term incentive plans, we granted stock options, performance and service-based restricted stock, and equity to officers, key employees, and members of the Board of Directors. Under the plans, we can grant up to a total of 18,000,000 shares. At December 31, 2003, we had stock options and restricted stock grants outstanding as discussed below.

Non-Qualified Stock Options

Options are granted with an exercise price not less than the market value of the common stock at the date of grant, become vested over a period up to five years, and expire ten years from the date of grant. In accordance with APB No. 25, no compensation expense is recognized for these awards.

In February 2002, our Compensation Committee of the Board of Directors granted options, contingent on shareholder approval of our long-term incentive plan, with an exercise price equal to the fair market value of our stock on the date of grant of $27.93. Our shareholders approved the plan at the annual meeting in May 2002 when then stock price had increased to $31.21. The difference between the exercise price and the fair market value in May when the shareholder approval contingency was satisfied was $6.3 million and is being amortized to compensation expense over a period up to five years. We recorded compensation expense of $1.8 million in 2003 and $3.0 million in 2002 related to this grant.

All other stock options grants have an exercise price equal to or greater than market value on the date of grant and were not subject to any future contingencies, therefore no compensation expense has been recognized. We reverse any expense associated with stock options that are canceled or forfeited prior to the vesting of the grants. Summarized information for our stock option grants is as follows:

	2003		2002		2001	
	Shares	Weighted-Average Exercise Price	Shares	Weighted-Average Exercise Price	Shares	Weighted-Average Exercise Price
	(In thousands, except for exercise prices)					
Outstanding, beginning of year	6,081	$29.65	2,646	$30.73	2,420	$34.65
Granted with Exercise Prices:						
At fair market value	1,485	29.24	1,708	30.62	1,015	25.08
Less than fair market value on the date contingency was satisfied (1)	—	—	1,935	27.93	—	—
Greater than fair market value	9	28.53	103	31.21	—	—
Total granted	1,494	29.24	3,746	29.25	1,015	25.08
Exercised	(267)	27.92	—	—	(512)	(34.25)
Canceled/Expired	(191)	33.28	(311)	34.01	(277)	(37.74)
Outstanding, end of year	7,117	$29.53	6,081	$29.65	2,646	$30.73
Exercisable, end of year	3,169	$29.89	1,413	$30.78	235	$34.25
Weighted-average fair value per share of options granted with Exercise Prices:						
At fair market value		$ 6.80		$ 7.79		$ 9.27
Less than fair market value on the date contingency was satisfied (1)		—		$ 9.15		—
Greater than fair market value		$ 5.56		$ 5.89		—

(1) Shares were granted in February 2002 with an exercise price equal to the fair market value of the stock on the grant date, and the grant was subject to shareholder approval of our long-term incentive plan. At the date of shareholder approval, the fair market value of the stock was higher than the grant date fair market value. Therefore, the difference is being amortized to compensation expense.

The following table summarizes information about stock options outstanding at December 31, 2003 (stock options in thousands):

Range of Exercise Prices	Stock Options Outstanding	Weighted-Average Remaining Contractual Life	Stock Options Exercisable
$21.47 - $36.82	7,117	8.1 years	3,169

Restricted Stock Awards

In addition, we issue common stock based on meeting certain performance and/or service goals. This stock vests to participants at various times ranging from one to five years if the performance and/or service goals are met. In accordance with APB No. 25, we recognize compensation expense for our performance-based awards using the variable accounting method, whereby we amortize the value of the market price of the underlying stock on the date of grant (adjusted for subsequent changes in fair market value through the performance measurement date) to compensation expense over the service period. We account for our service-based awards using the fixed accounting method, whereby we amortize the value of the market price of the underlying stock on the date of grant to compensation expense over the service period. We reverse any expense associated with restricted stock that is canceled or forfeited during the performance or service period.

We recorded compensation expense related to our restricted stock awards of $16.4 million in 2003 and $6.6 million in 2002. In 2001, due to non-attainment of performance criteria, we recorded a reduction to compensation expense of $10.1 million. Summarized share information for our restricted stock awards is as follows:

	2003	2002	2001
	(In thousands)		
Outstanding, beginning of year	314	435	377
Granted	555	344	87
Released to participants	(109)	(170)	—
Canceled	(8)	(295)	(29)
Outstanding, end of year	752	314	435
Weighted-average fair value restricted stock granted	$30.53	$27.23	$35.24

Equity-Based Grants

We recorded compensation expense of $0.4 million in 2003 and $0.5 million in 2002 related to equity-based grants to members of the Board of Directors.

Pro-forma Information

Disclosure of pro-forma information regarding net income and earnings per share is required under SFAS No. 123, which uses the fair value method. The fair value of our stock-based awards were estimated as of the date of grant using the Black-Scholes option pricing model based on the following weighted-average assumptions:

	2003	2002	2001
Risk-free interest rate	**2.92%**	4.45%	4.79%
Expected life (in years)	**5.0**	5.0	5.0
Expected market price volatility factor	**32.0%**	31.9%	41.3%
Expected dividend yield	**3.3%**	3.3%	1.8%

We disclose the pro-forma effect on net income and earnings per share in accordance with SFAS No. 148, *Accounting for Stock-Based Compensation—Transition and Disclosure*, in *Note 1*.

15 Acquisitions

Acquisition of Blackhawk Energy Services and Kaztex Energy Management

On October 22, 2003, we completed our purchase of Blackhawk Energy Services (Blackhawk) and Kaztex Energy Management (Kaztex). Blackhawk and Kaztex are providers of natural gas and electricity services, serving approximately 1,100 customers representing approximately 70 billion cubic feet of natural gas and 0.9 million megawatt hours of electricity throughout Illinois and Wisconsin. We acquired 100% ownership of both companies for $26.9 million cash. We acquired cash of $1.2 million as part of the purchase.

Our preliminary purchase price allocation for the net assets acquired is as follows:

At October 22, 2003

	(In millions)
Cash	$ 1.2
Other Current Assets	41.0
Total Current Assets	42.2
Net Property, Plant and Equipment	0.1
Goodwill	25.9
Other Assets	0.9
Total Assets Acquired	69.1
Current Liabilities	40.8
Deferred Credits and Other Liabilities	1.4
Net Assets Acquired	$26.9

We recorded the existing contracts at fair value as part of the purchase price allocation. The preliminary fair value of the contracts was a net liability of $0.4 million. We recorded the fair value of these contracts as follows:

Net fair value of acquired contracts

	(In millions)
Current Assets	$ 3.2
Noncurrent Assets	0.1
Total Assets	3.3
Current Liabilities	2.3
Noncurrent Liabilities	1.4
Total Liabilities	3.7
Net fair value of acquired contracts	$(0.4)

Acquired contracts include both executory contracts and risk management liabilities associated with certain hedges. We will amortize the acquired executory contracts over a period extending through 2008. The weighted-average amortization period is approximately 20 months and represents the expected contract duration. The risk management liabilities will be accounted for as described in *Note 1*.

There are further refinements to the preliminary valuation of the existing contracts that have not been finalized that could impact our purchase price allocation.

On an unaudited pro-forma basis, had the acquisition of Blackhawk and Kaztex occurred on the first day of each of the periods presented below, our nonregulated revenues and total revenues would have been as follows:

Year Ended December 31,	2003	2002	2001
		(In millions)	
Nonregulated revenues			
As reported	7,068.8	2,190.6	1,164.9
Pro-forma	7,423.7	2,418.1	1,468.3
Total revenues			
As reported	9,703.0	4,726.7	3,878.8
Pro-forma	10,057.9	4,954.2	4,182.2

We believe that the pro-forma impact on "Income before cumulative effect of change in accounting principle," "Net income," and "Earnings per common share" would not have been material had the acquisition of Blackhawk and Kaztex occurred on the first day of each of the years presented.

Acquisition of the High Desert Power Project

In April 2003, our High Desert Power Project in Victorville, California, an 830 megawatt (MW) gas-fired combined cycle facility, commenced operations. The project has a long-term power sales agreement with the California Department of Water Resources (CDWR). The contract is a "tolling" structure, under which the CDWR pays a fixed amount of $12.1 million per month and provides CDWR the right, but not the obligation, to purchase power from the project at a price linked to the variable cost of production. During the term of the contract, which runs for seven years and nine months from the April 2003 commercial operation date of the plant, the project will provide energy exclusively to the CDWR.

Prior to June 2003, we accounted for this project as an operating lease. In June 2003, we elected to refinance the lease to extend the tenor of the financing at attractive interest rates. Accordingly, we exercised our option under the lease associated with the High Desert Power Project, paid off the lease, and acquired the assets from the lessor. Beginning June 30, 2003, the assets and liabilities associated with the High Desert Power Project were included in our Consolidated Balance Sheets.

Our purchase price allocation for the net assets acquired is as follows:

At June 27, 2003

	(In millions)
Cash	$ 4.3
Other Current Assets	1.6
Other Noncurrent Assets	1.7
Net Property Plant and Equipment	528.3
Total Assets Acquired	535.9
Accounts Payable	(17.5)
Net Assets Acquired	$518.4

Other Acquisitions

As part of our growth strategy, our merchant energy business had other acquisitions including a synthetic fuel facility in South Carolina, various competitive energy supply contract portfolios with commercial and industrial customers, certain gas contracts and a wholesale marketing business in Canada.

Acquisition of Alliance

On December 31, 2002, we purchased Alliance Energy Services, LLC and Fellon-McCord Associates, Inc. (collectively, Alliance) from Allegheny Energy, Inc. These businesses provide gas supply and transportation services and energy consulting services to commercial and industrial customers primarily in the Mid-West region, but also in other competitive energy markets including the Northeast, Mid-Atlantic, Texas and California regions. We acquired 100% ownership of these companies for a note payable of $21.2 million that was settled in cash on January 2, 2003. Purchase price adjustments were finalized during 2003 which resulted in a reduction of $0.4 million to the purchase price. We acquired cash of $4.1 million as part of the purchase. We include these companies in our merchant energy business segment.

Our purchase price allocation for the net assets acquired is as follows:

At December 31, 2002

	(In millions)
Cash	$ 4.1
Other Current Assets	89.4
Total Current Assets	93.5
Net Property, Plant and Equipment	0.6
Goodwill	14.8
Other Assets	3.6
Total Assets Acquired	112.5
Current Liabilities	88.6
Deferred Credits and Other Liabilities	3.1
Net Assets Acquired	$20.8

We recorded the existing contracts at fair value as part of the purchase price allocation. The fair value of the contracts was a $4.0 million net asset. We recorded the fair value of these contracts as follows:

Net fair value of acquired contracts

	(In millions)
Current Assets	$25.3
Noncurrent Assets	3.7
Total Assets	29.0
Current Liabilities	21.9
Noncurrent Liabilities	3.1
Total Liabilities	25.0
Net fair value of acquired contracts	$ 4.0

Acquired contracts include both executory contracts and risk management assets and liabilities associated with certain hedges. We will amortize the acquired executory contracts over a period extending through 2005. The weighted-average amortization period is approximately one year and represents the expected contract duration. The risk management assets and liabilities will be accounted for as described in *Note 1*.

On an unaudited pro-forma basis, had the acquisition of Alliance occurred on the first day of each of the years presented below, our nonregulated revenues and total revenues would have been as follows:

Year Ended December 31,	2002	2001
	(In millions)	
Nonregulated revenues		
As reported	$2,190.6	$1,164.9
Pro-forma	2,730.3	1,659.5
Total revenues		
As reported	$4,726.7	$3,878.8
Pro-forma	5,266.4	4,373.4

We believe that the pro-forma impact on "Income before cumulative effect of change in accounting principle," "Net income," and "Earnings per common share" would not have been material had the acquisition of Alliance occurred on the first day of each of the years presented.

Acquisition of NewEnergy

On September 9, 2002, we purchased AES NewEnergy, Inc. from AES Corporation. Subsequent to the acquisition, we renamed AES NewEnergy, Inc. as Constellation NewEnergy, Inc. (NewEnergy). NewEnergy is a leading national provider of electricity, natural gas, and energy services, serving approximately 4,300 megawatts of load associated with commercial and industrial customers in competitive energy markets including the Northeast, Mid-Atlantic, Mid-West, Texas and California. We acquired 100% ownership of NewEnergy for cash of $251.6 million, including $1.6 million of direct costs associated with the acquisition. We acquired cash of $45.5 million as part of the purchase. We include NewEnergy in our merchant energy business segment.

Our purchase price allocation for the net assets acquired is as follows:

At September 9, 2002

	(In millions)
Cash	$ 45.5
Other Current Assets	377.8
Total Current Assets	423.3
Net Property, Plant and Equipment	7.0
Goodwill	100.6
Other Assets	48.7
Total Assets Acquired	579.6
Current Liabilities	283.2
Deferred Credits and Other Liabilities	44.8
Net Assets Acquired	$251.6

We recorded the existing contracts at fair value as part of the purchase price allocation. The fair value of the contracts was a $46.7 million net asset. We recorded the fair value of these contracts as follows:

Net fair value of acquired contracts

	(In millions)
Current Assets	$80.7
Noncurrent Assets	46.1
Total Assets	126.8
Current Liabilities	54.3
Noncurrent Liabilities	25.8
Total Liabilities	80.1
Net fair value of acquired contracts	$46.7

We will amortize this value over a period extending through 2007. The weighted-average amortization period is approximately 2 years and represents the expected contract duration.

On an unaudited pro-forma basis, had the acquisition of NewEnergy occurred on the first day of each of the years presented below, our nonregulated revenues and total revenues would have been as follows:

Year Ended December 31,	2002	2001
	(In millions)	
Nonregulated revenues		
As reported	$2,190.6	$1,164.9
Pro-forma	3,331.4	1,885.1
Total revenues		
As reported	$4,726.7	$3,878.8
Pro-forma	5,867.5	4,599.0

We believe that the pro-forma impact on "Income before cumulative effect of change in accounting principle," "Net income," and "Earnings per common share" would not have been material had the acquisition of NewEnergy occurred on the first day of each of the years presented.

16 Related Party Transactions—BGE

Income Statement

BGE is providing standard offer service to customers at fixed rates over various time periods during the transition period, July 1, 2000 to June 30, 2006, for those customers that do not choose an alternate supplier. Our wholesale marketing and risk management operation is under contract to provide BGE with the energy and capacity required to meet its standard offer service obligations for the first three years of the initial transition period. In August 2001, BGE entered into contracts with our wholesale marketing and risk management operation to supply 90% and Allegheny Energy Supply Company, LLC (Allegheny) to supply the remaining 10% of BGE's standard offer service for the final three years (July 1, 2003 to June 30, 2006) of the initial transition period. During the second quarter of 2003, after a competitive bid process, our wholesale marketing and risk management operation assumed the obligation from Allegheny to serve the remaining 10% of BGE's standard offer service for the remainder of the transition period.

The cost of BGE's purchased energy from nonregulated affiliates of Constellation Energy to meet its standard offer service obligation was as follows:

Year Ended December 31,	2003	2002	2001
		(In millions)	
Purchased energy	$1,023.4	$1,080.5	$1,150.1

In addition, Constellation Energy charges BGE for the costs of certain corporate functions. Certain costs are directly assigned to BGE. We allocate other corporate function costs based on a total percentage of expected use by BGE. Management believes this method of allocation is reasonable and approximates the cost BGE would have incurred as an unaffiliated entity. These costs were:

- $84.0 million for the year ended December 31, 2003,
- $37.6 million for the year ended December 31, 2002, and
- $33.3 million for the year ended December 31, 2001.

Balance Sheet

BGE participates in a cash pool under a Master Demand Note agreement with Constellation Energy. Under this arrangement, participating subsidiaries may invest in or borrow from the pool at market interest rates. Constellation Energy administers the pool and invests excess cash in short-term investments or issues commercial paper to manage consolidated cash requirements. Under this arrangement, BGE had invested $230.2 million at December 31, 2003 and $338.1 million at December 31, 2002.

Amounts related to corporate functions performed at the Constellation Energy holding company, BGE's purchases to meet its standard offer service obligation, BGE's charges to Constellation Energy and its nonregulated affiliates for certain services it provides them, and the participation of BGE's employees in the Constellation Energy pension plan result in intercompany balances on BGE's Consolidated Balance Sheets.

Management believes its allocation methods are reasonable and approximate the costs that would be charged to unaffiliated entities.

17 Quarterly Financial Data (Unaudited)

Our quarterly financial information has not been audited but, in management's opinion, includes all adjustments necessary for a fair 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.

2003 Quarterly Data—Constellation Energy

	Revenues	Income from Operations	Income Before Cumulative Effects of Changes in Accounting Principles	Earnings Applicable to Common Stock	Earnings Per Share Assuming Dilution Before Cumulative Effects of Changes in Accounting Principles	(Loss) Earnings Per Share of Common Stock-Diluted
	(In millions, except per share amounts)					
Quarter Ended						
March 31	$2,330.0	$ 175.6	$ 67.0	$(131.4)	$0.40	$(0.80)
June 30	2,271.1	229.1	96.8	96.8	0.58	0.58
September 30	2,604.4	389.2	192.9	192.9	1.15	1.15
December 31	2,497.5	272.4	119.0	119.0	0.71	0.71
Year Ended						
December 31	$9,703.0	$1,066.3	$475.7	$ 277.3	$2.85	$ 1.66

2003 Quarterly Data—BGE

	Revenues	Income from Operations	Earnings Applicable to Common Stock
		(In millions)	
Quarter Ended			
March 31	$ 789.8	$164.6	$ 78.5
June 30	577.0	69.2	21.7
September 30	663.3	62.8	20.6
December 31	617.5	88.4	29.2
Year Ended			
December 31	$2,647.6	$385.0	$150.0

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

First quarter results include:

Constellation Energy and BGE

- workforce reduction costs totaling $0.4 million after-tax, of which BGE recorded $0.1 million.

Constellation Energy

- a $266.1 million loss after-tax for the cumulative effect of adopting EITF 02-3,
- a $67.7 million gain after-tax for the cumulative effect of adopting SFAS 143, and
- gain on the sale of investments and other assets of $8.3 million after-tax.

Second quarter results include:

Constellation Energy and BGE

- workforce reduction costs totaling $0.4 million after-tax, of which BGE recorded $0.1 million.

Constellation Energy

- gain on the sale of investments of $0.3 million after-tax.

Third quarter results include:

Constellation Energy and BGE

- workforce reduction costs totaling $0.5 million after-tax, of which BGE recorded $0.2 million.

Constellation Energy

- net gain on sale of investment and other assets of $1.4 million after-tax.

Fourth quarter results include:

Constellation Energy

- net gain on sale of investments of $6.4 million after-tax and,
- an other than temporary decline in the value of our investment in an airplane of $0.4 million after-tax.

We discuss our special items in *Note 2*.

2002 Quarterly Data—Constellation Energy

	Revenues	Income from Operations	Earnings Applicable to Common Stock	Earnings Per Share of Common Stock
	(In millions, except per share amounts)			
Quarter Ended				
March 31	$1,053.5	$ 418.6	$228.6	$1.40
June 30	1,030.1	184.9	81.3	0.50
September 30	1,269.5	308.0	150.7	0.92
December 31	1,373.6	174.7	65.0	0.39
Year Ended				
December 31	$4,726.7	$1,086.2	$525.6	$3.20

2002 Quarterly Data—BGE

	Revenues	Income from Operations	Earnings Applicable to Common Stock
		(In millions)	
Quarter Ended			
March 31	$ 683.7	$113.0	$ 43.9
June 30	572.9	73.1	20.3
September 30	668.5	87.3	30.6
December 31	622.2	92.9	35.1
Year Ended			
December 31	$2,547.3	$366.3	$129.9

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

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

First quarter results include:
Constellation Energy and BGE
- workforce reduction costs totaling $15.6 million after-tax, of which BGE recorded $12.6 million.

Constellation Energy
- gain on the sale of investments, including Orion, of $164.2 million after-tax.

Second quarter results include:
Constellation Energy and BGE
- workforce reduction costs totaling $8.0 million after-tax, of which BGE recorded $4.8 million.

Constellation Energy
- gain on the sale of investments of $1.9 million after-tax, and
- loss on sale of turbine of $3.9 million after-tax.

Third quarter results include:
Constellation Energy and BGE
- workforce reduction costs totaling $7.5 million after-tax, of which BGE recorded $2.0 million.

Constellation Energy
- impairment of investments in qualifying facilities and domestic power projects, costs associated with exit of BGE Home merchandise stores, and impairment of real estate and international investments totaling $17.2 million after-tax.

Fourth quarter results include:
Constellation Energy and BGE
- workforce reduction costs totaling $6.9 million after-tax, of which BGE recorded $1.9 million.

Constellation Energy
- gains on the sale of investments of $4.5 million after-tax.

We discuss our special items in *Note 2*.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure
None.

Item 9A. Controls and Procedures
A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within Constellation Energy or BGE have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple error or mistake. Additionally, controls can be circumvented by the individual acts of some persons or by collusion of two or more people.

The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no absolute assurance that any design will succeed in achieving its stated goals under all potential future conditions; over time, controls may become inadequate because of changes in conditions, or the degree of compliance with the policies or procedures may deteriorate. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected.

The principal executive officers and principal financial officer of both Constellation Energy and BGE have evaluated the effectiveness of the disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")) as of the end of the period covered by this report (the "Evaluation Date"). Based on such evaluation, such officers have concluded that, as of the Evaluation Date, Constellation Energy's and BGE's disclosure controls and procedures are effective, in that they provide reasonable assurance that such officers are alerted on a timely basis to material information relating to Constellation Energy and BGE that is required to be included in Constellation Energy's and BGE's periodic filings under the Exchange Act.

PART III

BGE meets the conditions set forth in General Instruction I(1)(a)and (b) of Form 10-K for a reduced disclosure format. Accordingly, all items in this section related to BGE are not presented.

Item 10. Directors and Executive Officers of the Registrant
The information required by this item with respect to directors is set forth under *Election of Constellation Energy Directors* in the Proxy Statement and is incorporated herein by reference.

The information required by this item with respect to executive officers of Constellation Energy Group, pursuant to instruction 3 of paragraph (b) of Item 401 of Regulation S-K, is set forth in Item 4 of Part I of this Form 10-K under *Executive Officers of the Registrant.*

Item 11. Executive Compensation
The information required by this item is set forth under *Directors' Compensation, Executive Compensation, Common Stock Performance Graph* and *Report of Compensation Committee* in the Proxy Statement and is incorporated herein by reference.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Shareholder Matters

Equity Compensation Plan Information

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants, and rights	(b) Weighted-average exercise price of outstanding options, warrants, and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in item (a))
	(In thousands)		*(In thousands)*
Equity compensation plans approved by security holders	4,111	$29.44	5,660
Equity compensation plans not approved by security holders	3,006	$29.65	2,698
Total	7,117	$29.53	8,358

The plans that do not require security holder approval are the Constellation Energy Group, Inc. 2002 Senior Management Long-Term Incentive Plan (Designated as Exhibit No. 10(v)) and the Constellation Energy Group, Inc. Management Long-Term Incentive Plan (Designated as Exhibit No. 10(w)). Under these plans, we may grant up to a total of 7,000,000 equity shares. We have granted stock options and performance and service-based restricted stock to officers and key employees.

The additional information required by this item is set forth under *Security Ownership* in the Proxy Statement and is incorporated herein by reference.

Item 13. Certain Relationships and Related Transactions

The additional information required by this item is set forth under *Certain Relationships and Transactions* in the Proxy Statement and is incorporated herein by reference.

Item 14. Principal Accountant Fees and Services

The information required by this item is set forth under *Proposal No. 2—Ratification of PricewaterhouseCoopers LLP as Independent Auditors for 2004* in the Proxy Statement and is incorporated herein by reference.

PART IV

Item 15. Exhibits, Financial Statement Schedules and Reports on Form 8-K

(a) The following documents are filed as a part of this Report:

1. Financial Statements:
   Report of Independent Auditors dated January 28, 2004 of PricewaterhouseCoopers LLP
   Consolidated Statements of Income—Constellation Energy Group for three years ended December 31, 2003
   Consolidated Balance Sheets—Constellation Energy Group at December 31, 2003 and December 31, 2002
   Consolidated Statements of Cash Flows—Constellation Energy Group for three years ended December 31, 2003
   Consolidated Statements of Common Shareholders' Equity and Comprehensive Income—Constellation Energy Group for three years ended December 31, 2003
   Consolidated Statements of Capitalization—Constellation Energy Group at December 31, 2003 and December 31, 2002
   Consolidated Statements of Income—Baltimore Gas and Electric Company for three years ended December 31, 2003
   Consolidated Statements of Comprehensive Income—Baltimore Gas and Electric Company for three years ended December 31, 2003
   Consolidated Balance Sheets—Baltimore Gas and Electric Company at December 31, 2003 and December 31, 2002
   Consolidated Statements of Cash Flows—Baltimore Gas and Electric Company for three years ended December 31, 2003
   Notes to Consolidated Financial Statements
2. Financial Statement Schedules:
   Schedule II—Valuation and Qualifying Accounts
   Schedules other than Schedule II are omitted as not applicable or not required.
3. Exhibits Required by Item 601 of Regulation S-K.

Exhibit Number	
*2	— Agreement and Plan of Share Exchange between Baltimore Gas and Electric Company and Constellation Energy Group, Inc. dated as of February 19, 1999. (Designated as Exhibit No. 2 to the Registration Statement on Form S-4 dated March 3, 1999, File No. 33-64799.)
*2(a)	— Agreement and Plan of Reorganization and Corporate Separation (Nuclear). (Designated as Exhibit No. 2(a) to the Current Report on Form 8-K dated July 7, 2000, File Nos. 1-12869 and 1-1910.)
*2(b)	— Agreement and Plan of Reorganization and Corporate Separation (Fossil). (Designated as Exhibit No. 2(b) to the Current Report on Form 8-K dated July 7, 2000, File Nos. 1-12869 and 1-1910.)
*3(a)	— Articles of Amendment and Restatement of the Charter of Constellation Energy Group, Inc. as of April 30, 1999. (Designated as Exhibit No. 99.2 to the Current Report on Form 8-K dated April 30, 1999, File No. 1-1910.)
*3(b)	— Articles Supplementary to the Charter of Constellation Energy Group, Inc., as of July 19, 1999. (Designated as Exhibit No. 3(a) to the Quarterly Report on Form 10-Q for the quarter ended June 30, 1999, File Nos. 1-12869 and 1-1910.)
*3(c)	— Certificate of Correction to the Charter of Constellation Energy Group, Inc. as of September 13, 1999. (Designated as Exhibit No. 3(c) to the Annual Report on Form 10-K for the year ended December 31, 1999, File Nos. 1-12869 and 1-1910.)
*3(d)	— Charter of BGE, restated as of August 16, 1996. (Designated as Exhibit No. 3 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 1996, File No. 1-1910.)
*3(e)	— Articles Supplementary to the Charter of Constellation Energy Group, Inc. as of November 20, 2001. (Designated as Exhibit No. 3(e) to the Annual Report on Form 10-K for the year ended December 31, 2001, File Nos. 1-12869 and 1-1910.)

*3(f) — Bylaws of Constellation Energy Group, Inc., as amended to January 24, 2003. (Designated as Exhibit 3(f) to the Annual Report on Form 10-K for the year ended December 31, 2002, File Nos. 1-12869 and 1-1910.)

*3(g) — Bylaws of BGE, as amended to October 16, 1998. (Designated as Exhibit No. 3 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 1998, File No. 1-1910.)

*4(a) — Indenture between Constellation Energy Group, Inc. and the Bank of New York, Trustee dated as of March 24, 1999. (Designated as Exhibit No. 4(a) to the Registration Statement on Form S-3 dated March 29, 1999, File No. 333-75217.)

*4(b) — First Supplemental Indenture between Constellation Energy Group, Inc. and the Bank of New York, Trustee dated as of January 24, 2003. (Designated as Exhibit No. 4(b) to the Registration Statement on Form S-3 dated January 24, 2003, File No. 333-102723.)

*4(c) — Supplemental Indenture between BGE and Bankers Trust Company, as Trustee, dated as of June 20, 1995, supplementing, amending and restating Deed of Trust dated February 1, 1919. (Designated as Exhibit No. 4 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 1995, File No. 1-1910); and the following Supplemental Indentures between BGE and Bankers Trust Company, Trustee:

Dated	File No.	Designated In	Exhibit Number
*January 15, 1992	33-45259	(Form S-3 Registration)	4(a)(ii)
*February 15, 1993	1-1910	(Form 10-K Annual Report for 1992)	4(a)(i)
*March 1, 1993	1-1910	(Form 10-K Annual Report for 1992)	4(a)(ii)
*March 15, 1993	1-1910	(Form 10-K Annual Report for 1992)	4(a)(iii)
*April 15, 1993	1-1910	(Form 10-Q dated May 13, 1993)	4
*July 1, 1993	1-1910	(Form 10-Q dated August 13, 1993)	4(a)
*October 15, 1993	1-1910	(Form 10-Q dated November 12, 1993)	4
*June 15, 1996	1-1910	(Form 10-Q dated August 13, 1996)	4

*4(d) — Indenture dated July 1, 1985, between BGE and The Bank of New York (Successor to Mercantile-Safe Deposit and Trust Company), Trustee. (Designated as Exhibit 4(a) to the Registration Statement on Form S-3, File No. 2-98443); as supplemented by Supplemental Indentures dated as of October 1, 1987 (Designated as Exhibit 4(a) to the Current Report on Form 8-K, dated November 13, 1987, File No. 1-1910) and as of January 26, 1993 (Designated as Exhibit 4(b) to the Current Report on Form 8-K, dated January 29, 1993, File No. 1-1910.)

*4(e) — Form of Subordinated Indenture between the Company and The Bank of New York, as Trustee in connection with the issuance of the Junior Subordinated Debentures. (Designated as Exhibit 4(d) to the Registration Statement on Form S-3 dated August 5, 2003, File No. 333-107681.)

*4(f) — Form of Supplemental Indenture between the Company and The Bank of New York, as Trustee in connection with the issuances of the Junior Subordinated Debentures. (Designated as Exhibit 4(e) to the Registration Statement on Form S-3 dated August 5, 2003, File No. 333-107681.)

*4(g) — Form of Preferred Securities Guarantee (Designated as Exhibit 4(f) to the Registration Statement on Form S-3 dated August 5, 2003, File No. 333-107681.)

*4(h) — Form of Junior Subordinated Debenture (Designated as Exhibit 4(h) to the Registration Statement on Form S-3 dated August 5, 2003, File No. 333-107681.)

*4(i) — Form of Amended and Restated Declaration of Trust (including Form of Preferred Security) (Designated as Exhibit 4(c) to the Registration Statement on Form S-3 dated August 5, 2003, File No. 333-107681.)

*10(a) — Executive Annual Incentive Plan of Constellation Energy Group, Inc., as amended and restated. (Designated as Exhibit No. 10(a) to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2003, File Nos. 1-12869 and 1-1910.)

*10(b) — Constellation Energy Group, Inc. 1995 Long-Term Incentive Plan, as amended and restated. (Designated as Exhibit No. 10(b) to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2003, File Nos. 1-12869 and 1-1910.)

*10(c) — Constellation Energy Group, Inc. Nonqualified Deferred Compensation Plan, as amended and restated. (Designated as Exhibit No. 10(c) to the Annual Report on Form 10-K for the year ended December 31, 2002, File Nos. 1-12869 and 1-1910.)

*10(d) — Constellation Energy Group, Inc. Deferred Compensation Plan for Non-Employee Directors, as amended and restated. (Designated as Exhibit No. 10(c) to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2003, File Nos. 1-12869 and 1-1910.)

*10(e) — Baltimore Gas and Electric Company Retirement Plan for Non-Employee Directors, as amended and restated. (Designated as Exhibit No. 10(m) in Form 10-Q dated May 14, 1999, File Nos. 1-12869 and 1-1910.)

*10(f) — Summary of severance arrangement for Edward A. Crooke. (Designated as Exhibit No. 10(g) to the Annual Report on Form 10-K for the year ended December 31, 1999, File Nos. 1-12869 and 1-1910.)

*10(g) — Grantor Trust Agreement Dated as of April 25, 2003 between Constellation Energy Group, Inc. and Citibank, N.A. (Designated as Exhibit No. 10(d) to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2003, File Nos. 1-12869 and 1-1910.)

*10(h) — Form of Severance Agreements between Constellation Energy Group, Inc. and the following named executive officers: Mayo A. Shattuck III, E. Follin Smith, and Frank O. Heintz. (Designated as Exhibit 10(h) to the Annual Report on Form 10-K for the year ended December 31, 2002, File Nos. 1-12869 and 1-1910.)

*10(i) — Grantor Trust Agreement dated as of April 25, 2003 between Constellation Energy Group, Inc. and T. Rowe Price Trust Company. (Designated as Exhibit No. 10(e) to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2003, File Nos. 1-12869 and 1-1910.)

*10(j) — Full Requirements Service Agreement between Constellation Power Source, Inc. and Baltimore Gas and Electric Company. (Designated as Exhibit No. 10(a) to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2000, File Nos. 1-12869 and 1-1910.) (Portions of this exhibit have been omitted pursuant to a request for confidential treatment.)

*10(k) — Full Requirements Service Agreement between Constellation Power Source, Inc. and Baltimore Gas and Electric Company. (Designated as Exhibit No. 10(a) to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2001, File Nos. 1-12869 and 1-1910.) (Portions of this exhibit have been omitted pursuant to a request for confidential treatment.)

*10(l) — Full Requirements Service Agreement between Baltimore Gas and Electric Company and Allegheny Energy Supply Company, L.L.C. (Designated as Exhibit No. 10(b) to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2001, File Nos. 1-12869 and 1-1910.) (Portions of this exhibit have been omitted pursuant to a request for confidential treatment.)

*10(m) — Consent to Assignment and Assumption Agreement by and among Allegheny Energy Supply, LLC and Baltimore Gas and Electric Company and Constellation Power Source, Inc. (Designated as Exhibit 10(l) to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2003, File Nos. 1-12869 and 1-1910.) (Portions of this exhibit have been omitted pursuant to a request for confidential treatment.)

*10(n) — Constellation Energy Group, Inc. Benefits Restoration Plan, as amended and restated. (Designated as Exhibit No. 10(m) to the Annual Report on Form 10-K for the year ended December 31, 2001, File Nos. 1-12869 and 1-1910.)

*10(o) — Constellation Energy Group, Inc. Supplemental Pension Plan, as amended and restated. (Designated as Exhibit No. 10(f) to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2003, File Nos. 1-12869 and 1-1910.)

*10(p) — Constellation Energy Group, Inc. Senior Executive Supplemental Plan, as amended and restated. (Designated as Exhibit No. 10(g) to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2003, File Nos. 1-12869 and 1-1910.)

*10(q) — Constellation Energy Group, Inc. Supplemental Benefits Plan, as amended and restated. (Designated as Exhibit No. 10(p) to the Annual Report on Form 10-K for the year ended December 31, 2001, File Nos. 1-12869 and 1-1910.)

*10(r) — Compensation agreements between Constellation Energy Group, Inc. and Michael J. Wallace (Attachment 1—Employment Agreement; Attachment 2—Severance Agreement.) (Designated as Exhibit 10(q) to the Annual Report on Form 10-K for the year ended December 31, 2002, File Nos. 1-12869 and 1-1910.)

*10(s) — Compensation agreements between Constellation Energy Group, Inc. and Thomas V. Brooks (Attachment 1—Offer letter; Attachment 2—Equity letter; Attachment 3—Retention plan summary.) (Designated as Exhibit No. 10(r) to the Annual Report on Form 10-K for the year ended December 31, 2001, File Nos. 1-12869 and 1-1910.)

*10(t) — Constellation Energy Group, Inc. Executive Long-Term Incentive Plan, as amended and restated. (Designated as Exhibit 10(h) to the Quarter Report on Form 10-Q for the quarter ended June 30, 2003, File Nos. 1-12869 and 1-1910.)

*10(u) — Constellation Energy Group, Inc. 2002 Executive Annual Incentive Plan, as amended and restated. (Designated as Exhibit 10(i) to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2003, File Nos. 1-12869 and 1-1910.)

*10(v) — Constellation Energy Group, Inc. 2002 Senior Management Long-Term Incentive Plan, as amended and restated. (Designated as Exhibit 10(j) to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2003, File Nos. 1-12869 and 1-1910.)

*10(w) — Constellation Energy Group, Inc. Management Long-Term Incentive Plan, as amended and restated. (Designated as Exhibit 10(k) to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2003, File Nos. 1-2869 and 1-1910.)

*10(x) — Compensation agreements between Constellation Energy Group, Inc. and E. Follin Smith (Attachment 1. Offer letter; Attachment 2—Severance agreement.) (Designated as Exhibit 10(w) to the Annual Report on Form 10-K for the year ended December 31, 2002.)

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

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

21 — Subsidiaries of the Registrant.

23 — Consent of PricewaterhouseCoopers LLP, Independent Auditors.

31(a) — Certification of Chairman of the Board, Chief Executive Officer and President of Constellation Energy Group, Inc. pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31(b) — Certification of Executive Vice President and Chief Financial Officer of Constellation Energy Group, Inc. pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31(c) — Certification of President and Chief Executive Officer of Baltimore Gas and Electric Company pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31(d) — Certification of Senior Vice President and Chief Financial Officer of Baltimore Gas and Electric Company pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

32(a) — Certification of Chairman of the Board, Chief Executive Officer and President of Constellation Energy Group, Inc. pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

32(b) — Certification of Executive Vice President and Chief Financial Officer of Constellation Energy Group, Inc. pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

32(c) — Certification of President and Chief Executive Officer of Baltimore Gas and Electric Company pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

32(d) — Certification of Senior Vice President and Chief Financial Officer of Baltimore Gas and Electric Company pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Incorporated by Reference.

(b) Reports on Form 8-K:

Date	Item Reported
October 30, 2003	Item 7. Financial Statements and Exhibits
	Item 12. Results of Operations and Financial Condition
November 25, 2003	Item 5. Other Events
	Item 7. Financial Statements and Exhibits

CONSTELLATION ENERGY GROUP, INC. AND SUBSIDIARIES
AND
BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARIES
SCHEDULE II—VALUATION AND QUALIFYING ACCOUNTS

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at beginning of period	Charged to costs and expenses	Charged to Other Accounts—Describe	(Deductions)—Describe	Balance at end of period
			(In millions)		
Reserves deducted in the Balance Sheet from the assets to which they apply:					
Constellation Energy					
Accumulated Provision for Uncollectibles					
2003	$ 41.9	$22.0	$ —	$ (12.2)(A)	$ 51.7
2002	22.8	26.4	12.5 (B)	(19.8)(A)	41.9
2001	21.3	26.5	—	(25.0)(A)	22.8
Valuation Allowance—					
Net unrealized (gain) loss on available for sale securities					
2003	—	—	—	—	—
2002	(243.7)	—	243.7 (C)	—	—
2001	(33.7)	—	(210.0)(C)	—	(243.7)
Net unrealized (gain) loss on nuclear decommissioning trust funds					
2003	47.4	—	(61.1)(C)	—	(13.7)
2002	(21.0)	—	68.4 (C)	—	47.4
2001	(34.7)	—	13.7 (C)	—	(21.0)
Mark-to-market energy assets reserves					
2003	49.9	(15.2) (D)	(4.4)(E)	(5.5) (F)	24.8
2002	43.4	—	6.5 (E)	—	49.9
2001	54.4	—	(11.0)(E)	—	43.4
BGE					
Accumulated Provision for Uncollectibles					
2003	11.5	9.0	—	(9.8)(A)	10.7
2002	13.4	14.5	—	(16.4)(A)	11.5
2001	13.4	21.8	—	(21.8)(A)	13.4

(A) Represents principally net amounts charged off as uncollectible.
(B) Represents amounts acquired resulting from our acquisitions of NewEnergy and Alliance.
(C) Represents amounts recorded in or reclassified from accumulated other comprehensive income.
(D) Represents amounts credited to "Cumulative effects of changes in accounting principles" in our Consolidated Statements of Income for non-derivative contracts removed from our Consolidated Balance Sheets in connection with the adoption of Emerging Issues Task Force (EITF) Issue 02-3, *Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities.*
(E) Represents reserves from mark-to-market energy assets (credited) charged to revenues.
(F) Represents reserves from derivatives classified as "Mark-to-market energy assets" at December 31, 2002, which were designated as hedges and reclassified in our Consolidated Balance Sheets to "Risk management assets and liabilities" upon adoption of EITF 02-3.

SIGNATURES

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

CONSTELLATION ENERGY GROUP, INC.
(Registrant)

Date: March 9, 2004

By /s/ MAYO A. SHATTUCK III

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

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

Signature	Title	Date
Principal executive officer and director:		
By /s/ M. A. Shattuck III **M. A. Shattuck III**	Chairman of the Board, Chief Executive Officer, President and Director	March 9, 2004
Principal financial and accounting officer:		
By /s/ E. F. Smith **E. F. Smith**	Executive Vice President, Chief Financial Officer and Chief Administrative Officer	March 9, 2004
Directors:		
/s/ D. L. Becker **D. L. Becker**	Director	March 9, 2004
/s/ J. T. Brady **J. T. Brady**	Director	March 9, 2004
/s/ F. P. Bramble, Sr. **F. P. Bramble, Sr.**	Director	March 9, 2004
/s/ E. A. Crooke **E. A. Crooke**	Director	March 9, 2004
/s/ J. R. Curtiss **J. R. Curtiss**	Director	March 9, 2004
/s/ Y.C. de Balmann **Y.C. de Balmann**	Director	March 9, 2004

	Signature	Title	Date
/s/	R. W. Gale **R. W. Gale**	Director	March 9, 2004
/s/	F. A. Hrabowski, III **F. A. Hrabowski, III**	Director	March 9, 2004
/s/	E. J. Kelly, III **E. J. Kelly, III**	Director	March 9, 2004
/s/	N. Lampton **N. Lampton**	Director	March 9, 2004
/s/	R. J. Lawless **R. J. Lawless**	Director	March 9, 2004
/s/	L. M. Martin **L. M. Martin**	Director	March 9, 2004
/s/	M. D. Sullivan **M. D. Sullivan**	Director	March 9, 2004

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

BALTIMORE GAS AND ELECTRIC COMPANY
(Registrant)

Date: March 9, 2004

By /s/ FRANK O. HEINTZ

Frank O. Heintz
President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this Report has been signed below by the following persons on behalf of Baltimore Gas and Electric Company, the Registrant, and in the capacities and on the dates indicated.

Signature	Title	Date
Principal executive officer and director:		
By /s/ F. O. Heintz **F. O. Heintz**	President, Chief Executive Officer, and Director	March 9, 2004
Principal financial and accounting officer and director:		
By /s/ E. F. Smith **E. F. Smith**	Senior Vice President, Chief Financial Officer, and Director	March 9, 2004
Directors:		
/s/ M. A. Shattuck III **M. A. Shattuck III**	Director	March 9, 2004

CONSTELLATION ENERGY GROUP, INC.
CERTIFICATION

I, Mayo A. Shattuck III, certify that:

1. I have reviewed this report on Form 10-K of Constellation Energy Group, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(c) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal controls over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 9, 2004

/s/ MAYO A. SHATTUCK III

Chairman of the Board, Chief Executive Officer and President

CONSTELLATION ENERGY GROUP, INC.

CERTIFICATION

I, E. Follin Smith, certify that:

1. I have reviewed this report on Form 10-K of Constellation Energy Group, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(c) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal controls over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 9, 2004

/s/ E. FOLLIN SMITH

Executive Vice President and Chief Financial Officer

BALTIMORE GAS AND ELECTRIC COMPANY

CERTIFICATION

I, Frank O. Heintz, certify that:

1. I have reviewed this report on Form 10-K of Baltimore Gas and Electric Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(c) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal controls over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 9, 2004

/s/ FRANK O. HEINTZ

President and Chief Executive Officer

BALTIMORE GAS AND ELECTRIC COMPANY
CERTIFICATION

I, E. Follin Smith, certify that:

1. I have reviewed this report on Form 10-K of Baltimore Gas and Electric Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(c) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal controls over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 9, 2004

/s/ E. FOLLIN SMITH

Senior Vice President and Chief Financial Officer

Exhibit 32(a)

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350 AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

I, Mayo A. Shattuck III, Chairman of the Board, Chief Executive Officer and President of Constellation Energy Group, Inc., certify pursuant to 18 U.S.C. Section 1350 adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that to my knowledge:

(i) The accompanying Annual Report on Form 10-K for the year ended December 31, 2003 fully complies with the requirements of Section 13(a) or Section 15(d) of the Securities Exchange Act of 1934, as amended; and

(ii) The information contained in such report fairly presents, in all material respects, the financial condition and results of operations of Constellation Energy Group, Inc.

/s/ MAYO A. SHATTUCK III

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

Date: March 9, 2004

Exhibit 32(b)

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350 AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

I, E. Follin Smith, Executive Vice President and Chief Financial Officer of Constellation Energy Group, Inc., certify pursuant to 18 U.S.C. Section 1350 adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that to my knowledge:

(i) The accompanying Annual Report on Form 10-K for the year ended December 31, 2003 fully complies with the requirements of Section 13(a) or Section 15(d) of the Securities Exchange Act of 1934, as amended; and

(ii) The information contained in such report fairly presents, in all material respects, the financial condition and results of operations of Constellation Energy Group, Inc.

/s/ E. FOLLIN SMITH

E. Follin Smith
Executive Vice President and Chief Financial Officer

Date: March 9, 2004

Exhibit 32(c)

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350 AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

I, Frank O. Heintz, President and Chief Executive Officer of Baltimore Gas and Electric Company, certify pursuant to 18 U.S.C. Section 1350 adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that to my knowledge:

(i) The accompanying Annual Report on Form 10-K for the year ended December 31, 2003 fully complies with the requirements of Section 13(a) or Section 15(d) of the Securities Exchange Act of 1934, as amended; and

(ii) The information contained in such report fairly presents, in all material respects, the financial condition and results of operations of Baltimore Gas and Electric Company.

/s/ FRANK O. HEINTZ

Frank O. Heintz
President and Chief Executive Officer

Date: March 9, 2004

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350 AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

I, E. Follin Smith, Senior Vice President and Chief Financial Officer of Baltimore Gas and Electric Company, certify pursuant to 18 U.S.C. Section 1350 adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that to my knowledge:

(i) The accompanying Annual Report on Form 10-K for the year ended December 31, 2003 fully complies with the requirements of Section 13(a) or Section 15(d) of the Securities Exchange Act of 1934, as amended; and

(ii) The information contained in such report fairly presents, in all material respects, the financial condition and results of operations of Baltimore Gas and Electric Company.

/s/ E. FOLLIN SMITH

E. Follin Smith
Senior Vice President and Chief Financial Officer

Date: March 9, 2004

Shareholder Information

Common Stock Dividends and Price Ranges

2003 Dividend Declared		Price* High	Price* Low
First Quarter	$0.26	$30.23	$25.17
Second Quarter	0.26	34.92	27.50
Third Quarter	0.26	37.65	31.75
Fourth Quarter	0.26	39.61	35.03
Total	$1.04		

2002 Dividend Declared		Price* High	Price* Low
First Quarter	$0.24	$31.18	$26.16
Second Quarter	0.24	32.38	27.65
Third Quarter	0.24	29.85	21.51
Fourth Quarter	0.24	29.02	19.30
Total	$0.96		

** Based on NYSE composite transactions*

Dividend Policy
Constellation Energy pays dividends on its common stock after its Board of Directors declares them. There are no contractual limitations on Constellation Energy paying common stock dividends. Dividends have been paid continuously on our common stock since 1910. Future dividends depend upon future earnings, our financial condition, and other factors.

Dividend Increase
In January 2004, we announced an increase in our quarterly dividend from 26 cents to 28.5 cents per share on our common stock payable April 1, 2004, to holders of record on March 10, 2004. This is equivalent to an annual rate of $1.14 per share.

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 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.

Form 10-K
The company has furnished a copy of its Form 10-K as a part of this annual report. In addition, our Form 10-K and other SEC filings can be found on our Web site, constellation.com. Upon written request the company will furnish, without charge, additional copies of its Form 10-K. Requests should be sent to Constellation Energy, Shareholder Services, Ellen Trippe, 750 East Pratt Street, Baltimore, MD 21202.

Auditor
PricewaterhouseCoopers LLP

Forward Looking Disclaimer
We make statements in this Annual Report that are considered forward looking within the meaning of the Securities Exchange Act of 1934. These statements are not guarantees of our future results and are subject to risks, uncertainties, and other important factors that could cause our actual results to differ, including those set forth in our Form 10-K under the "Forward Looking Statements" section.

Shareholder Investment Plan
Constellation Energy'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 Agent and Registrar
American Stock Transfer & Trust Company
Shareholder Services
59 Maiden Lane
New York, NY 10038
800-258-0499
www.amstock.com

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, please contact our stock transfer agent by mail, telephone, or online. The contact information is listed above in the Stock Transfer Agent and Registrar section.

New Shareholder Account Numbers
Your shareholder account number has changed to a new format that gives you easy telephone and online access to your account. The new format uses your old shareholder account number and simply adds a 9 and 0s to the front to make it a 10-digit number.

You can determine what your new shareholder account number will be by following these steps:

1. Find your old shareholder account number on one of your dividend check stubs or investment plan statements.
2. Add a 9 and then add enough 0s to the front of your old shareholder account number to make it a 10-digit number. For example, if your old account number is 1234, your new account number is 9000001234.

Constellation Energy

The way energy **works.**

750 E. Pratt Street
Baltimore, MD 21202-3106

constellation.com

EXHIBIT II

QUARTERLY FINANCIAL STATEMENTS

AS OF MARCH 31, 2004

Calvert Cliffs Nuclear Power Plant, Inc.
July 30, 2004

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For The Quarterly Period Ended March 31, 2004

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

MARYLAND
(State of Incorporation of both registrants)

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

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

NOT APPLICABLE
(Former name, former address and former fiscal year, if changed since last report)

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months, and (2) have been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether Constellation Energy Group, Inc. is an accelerated filer Yes ☒ No ☐

Indicate by check mark whether Baltimore Gas and Electric Company is an accelerated filer Yes ☐ No ☒

COMMON STOCK, WITHOUT PAR VALUE 168,490,454 SHARES OUTSTANDING OF CONSTELLATION ENERGY GROUP, INC. ON APRIL 30, 2004.

Baltimore Gas and Electric Company meets the conditions set forth in General Instruction H(1)(a) and (b) of Form 10-Q and is therefore filing this form in the reduced disclosure format.

TABLE OF CONTENTS

PART 1—FINANCIAL INFORMATION
Item 1—Financial Statements

CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

Constellation Energy Group, Inc. and Subsidiaries

Three Months Ended March 31,	2004	2003
	(In millions, except per share amounts)	
Revenues		
Nonregulated revenues	$2,234.3	$1,545.5
Regulated electric revenues	484.4	486.3
Regulated gas revenues	317.9	298.2
Total revenues	3,036.6	2,330.0
Expenses		
Operating expenses	2,600.7	1,978.0
Depreciation and amortization	123.0	111.1
Accretion of asset retirement obligations	11.2	10.7
Taxes other than income taxes	67.5	68.3
Total expenses	2,802.4	2,168.1
Net Gain on Sales of Investments and Other Assets	1.5	13.7
Income from Operations	235.7	175.6
Other Income	4.8	8.9
Fixed Charges		
Interest expense	84.8	82.3
Interest capitalized and allowance for borrowed funds used during construction	(2.6)	(4.4)
BGE preference stock dividends	3.3	3.3
Total fixed charges	85.5	81.2
Income from Continuing Operations Before Income Taxes	155.0	103.3
Income Taxes	42.5	36.3
Income from Continuing Operations and Before Cumulative Effects of Changes in Accounting Principles	112.5	67.0
Loss from Discontinued Operations, Net of Income Taxes of $23.8	(46.3)	—
Cumulative Effects of Changes in Accounting Principles, Net of Income Taxes of $119.5	—	(198.4)
Net Income (Loss)	$ 66.2	$ (131.4)
Earnings (Loss) Applicable to Common Stock	$ 66.2	$ (131.4)
Average Shares of Common Stock Outstanding—Basic	168.1	164.9
Average Shares of Common Stock Outstanding—Diluted	169.2	164.9
Earnings Per Common Share and Earnings Per Common Share—Assuming Dilution from Continuing Operations and Before Cumulative Effects of Changes in Accounting Principles	$ 0.66	$ 0.40
Loss from Discontinued Operations	(0.27)	—
Cumulative Effects of Changes in Accounting Principles	—	(1.20)
Earnings (Loss) Per Common Share and Earnings (Loss) Per Common Share—Assuming Dilution	$ 0.39	$ (0.80)
Dividends Declared Per Common Share	$ 0.285	$ 0.260

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

Constellation Energy Group, Inc. and Subsidiaries

Three Months Ended March 31,	2004	2003
	(In millions)	
Net Income (Loss)	$ 66.2	$ (131.4)
Other comprehensive income (OCI)		
Reclassification of net gain on sales of securities from OCI to net income, net of taxes	(0.3)	(2.6)
Reclassification of net gain on hedging instruments from OCI to net income, net of taxes	(24.8)	(6.0)
Net unrealized gain (loss) on hedging instruments, net of taxes	96.3	(6.0)
Net unrealized gain (loss) on securities, net of taxes	26.9	(11.7)
Comprehensive Income (Loss)	$ 164.3	$ (157.7)

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

CONSOLIDATED BALANCE SHEETS

Constellation Energy Group, Inc. and Subsidiaries

	March 31, 2004*	*December 31,* 2003
	(In millions)	
Assets		
Current Assets		
Cash and cash equivalents	$ 840.8	$ 721.3
Accounts receivable (net of allowance for uncollectibles of $53.5 and $51.7, respectively)	1,441.1	1,563.0
Mark-to-market energy assets	569.5	488.3
Risk management assets	577.7	249.5
Materials and supplies	202.9	211.7
Fuel stocks	108.9	178.2
Assets held for sale—discontinued operations	87.6	—
Acquired contracts, net of amortization	50.9	67.0
Other	177.8	154.4
Total current assets	4,057.2	3,633.4
Investments and Other Assets		
Nuclear decommissioning trust funds	792.5	736.1
Investments in qualifying facilities and power projects	328.1	332.6
Mark-to-market energy assets	343.5	261.9
Risk management assets	251.6	158.4
Goodwill	144.1	144.0
Acquired contracts, net of amortization	98.8	105.8
Other	238.1	238.0
Total investments and other assets	2,196.7	1,976.8
Property, Plant and Equipment		
Regulated property, plant and equipment	5,285.8	5,266.7
Nonregulated generation property, plant and equipment	7,614.9	7,769.1
Other nonregulated property, plant and equipment	404.2	340.9
Nuclear fuel (net of amortization)	229.6	202.9
Accumulated depreciation	(4,001.4)	(3,978.1)
Net property, plant and equipment	9,533.1	9,601.5
Deferred Charges		
Regulatory assets (net)	211.1	229.5
Other	138.2	149.6
Total deferred charges	349.3	379.1
Total Assets	$16,136.3	$15,590.8

* *Unaudited*

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

CONSOLIDATED BALANCE SHEETS

Constellation Energy Group, Inc. and Subsidiaries

	March 31, 2004*	*December 31,* 2003
	(In millions)	
Liabilities and Equity		
Current Liabilities		
Short-term borrowings	$ 7.5	$ 9.6
Current portion of long-term debt	362.9	343.2
Accounts payable	1,051.1	1,167.7
Customer deposits and collateral	235.9	181.7
Mark-to-market energy liabilities	544.3	474.6
Risk management liabilities	193.9	134.6
Liabilities associated with assets held for sale	47.5	—
Other	442.7	523.6
Total current liabilities	2,885.8	2,835.0
Deferred Credits and Other Liabilities		
Deferred income taxes	1,466.4	1,384.4
Mark-to-market energy liabilities	355.1	258.0
Risk management liabilities	404.0	170.1
Asset retirement obligations	605.1	595.9
Postretirement and postemployment benefits	364.2	361.8
Net pension liability	185.6	225.7
Deferred investment tax credits	76.6	78.4
Other	197.5	198.4
Total deferred credits and other liabilities	3,654.5	3,272.7
Long-term Debt		
Long-term debt of Constellation Energy	3,350.0	3,350.0
Long-term debt of nonregulated businesses	384.9	389.2
First refunding mortgage bonds of BGE	476.1	476.1
Other long-term debt of BGE	919.6	919.6
6.20% deferrable interest subordinated debentures due October 15, 2043 to BGE wholly owned BGE Capital Trust II relating to trust preferred securities	257.7	257.7
Unamortized discount and premium	(12.8)	(10.2)
Current portion of long-term debt	(362.9)	(343.2)
Total long-term debt	5,012.6	5,039.2
Minority Interests	115.7	113.4
BGE Preference Stock Not Subject to Mandatory Redemption	190.0	190.0
Common Shareholders' Equity		
Common stock	2,200.6	2,179.8
Retained earnings	2,100.2	2,081.9
Accumulated other comprehensive loss	(23.1)	(121.2)
Total common shareholders' equity	4,277.7	4,140.5
Commitments, Guarantees, and Contingencies (see Notes)		
Total Liabilities and Equity	$16,136.3	$15,590.8

* *Unaudited*

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

CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

Constellation Energy Group, Inc. and Subsidiaries

Three Months Ended March 31,	2004	2003
	(In millions)	
Cash Flows From Operating Activities		
Net income (loss)	$ 66.2	$ (131.4)
Adjustments to reconcile to net cash provided by operating activities		
Loss from discontinued operations	46.3	—
Cumulative effects of changes in accounting principles	—	198.4
Depreciation and amortization	156.6	139.4
Accretion of asset retirement obligations	11.2	10.7
Deferred income taxes	27.8	30.5
Investment tax credit adjustments	(1.8)	(1.8)
Deferred fuel costs	4.0	(24.9)
Pension and postemployment benefits	(36.9)	(98.1)
Net gain on sales of investments and other assets	(1.5)	(13.7)
Equity in earnings of affiliates less than dividends received	3.3	8.7
Changes in		
Accounts receivable	119.2	(559.4)
Mark-to-market energy assets and liabilities	4.0	37.1
Risk management assets and liabilities	2.2	(61.6)
Materials, supplies and fuel stocks	71.9	44.8
Other current assets	(25.9)	(40.9)
Accounts payable	(121.6)	486.0
Other current liabilities	7.4	190.2
Other	(0.8)	28.8
Net cash provided by operating activities	331.6	242.8
Cash Flows From Investing Activities		
Purchases of property, plant and equipment	(171.3)	(145.2)
Contributions to nuclear decommissioning trust funds	(8.8)	(4.4)
Sales of investments and other assets	6.7	89.8
Other investments	(7.4)	(21.9)
Net cash used in investing activities	(180.8)	(81.7)
Cash Flows From Financing Activities		
Net (maturity) issuance of short-term borrowings	(2.1)	1.9
Proceeds from issuance of common stock	15.2	10.1
Repayment of long-term debt	(2.4)	(134.9)
Common stock dividends paid	(43.5)	(39.6)
Other	1.5	(1.4)
Net cash used in financing activities	(31.3)	(163.9)
Net Increase (Decrease) in Cash and Cash Equivalents	119.5	(2.8)
Cash and Cash Equivalents at Beginning of Period	721.3	615.0
Cash and Cash Equivalents at End of Period	$ 840.8	$ 612.2

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

CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

Baltimore Gas and Electric Company and Subsidiaries

Three Months Ended March 31,	2004	2003
	(In millions)	
Revenues		
Electric revenues	$484.4	$486.3
Gas revenues	319.5	303.5
Total revenues	803.9	789.8
Expenses		
Operating expenses		
Electricity purchased for resale	240.4	243.6
Gas purchased for resale	216.0	203.1
Operations and maintenance	92.6	77.4
Depreciation and amortization	59.9	55.9
Taxes other than income taxes	45.2	45.2
Total expenses	654.1	625.2
Income from Operations	149.8	164.6
Other Income	1.0	0.3
Fixed Charges		
Interest expense	25.4	30.0
Allowance for borrowed funds used during construction	(0.3)	(0.5)
Total fixed charges	25.1	29.5
Income Before Income Taxes	125.7	135.4
Income Taxes	49.7	53.6
Net Income	76.0	81.8
Preference Stock Dividends	3.3	3.3
Earnings Applicable to Common Stock	$ 72.7	$ 78.5

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

CONSOLIDATED BALANCE SHEETS

Baltimore Gas and Electric Company and Subsidiaries

	March 31, 2004*	*December 31,* 2003
	(In millions)	
Assets		
Current Assets		
Cash and cash equivalents	$ 7.9	$ 11.0
Accounts receivable (net of allowance for uncollectibles of $11.7 and $10.7, respectively)	359.1	354.8
Investment in cash pool, affiliated company	358.8	230.2
Accounts receivable, affiliated companies	1.6	4.5
Fuel stocks	14.9	62.8
Materials and supplies	32.8	29.9
Prepaid taxes other than income taxes	21.5	42.8
Other	9.3	9.9
Total current assets	805.9	745.9
Other Assets		
Receivable, affiliated company	159.4	131.6
Other	92.1	90.4
Total other assets	251.5	222.0
Utility Plant		
Plant in service		
Electric	3,624.7	3,599.3
Gas	1,071.4	1,064.7
Common	460.9	467.7
Total plant in service	5,157.0	5,131.7
Accumulated depreciation	(1,832.9)	(1,807.7)
Net plant in service	3,324.1	3,324.0
Construction work in progress	124.3	130.5
Plant held for future use	4.5	4.5
Net utility plant	3,452.9	3,459.0
Deferred Charges		
Regulatory assets (net)	211.1	229.5
Other	48.2	50.2
Total deferred charges	259.3	279.7
Total Assets	$ 4,769.6	$ 4,706.6

** Unaudited*

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

CONSOLIDATED BALANCE SHEETS

Baltimore Gas and Electric Company and Subsidiaries

	March 31, 2004*	*December 31,* 2003
	(In millions)	
Liabilities and Equity		
Current Liabilities		
Current portion of long-term debt	$ 350.6	$ 330.6
Accounts payable	83.8	111.2
Accounts payable, affiliated companies	189.1	151.7
Customer deposits	60.7	59.7
Accrued taxes	63.1	33.0
Accrued interest	34.5	22.3
Other	15.8	43.3
Total current liabilities	797.6	751.8
Deferred Credits and Other Liabilities		
Deferred income taxes	594.8	585.8
Postretirement and postemployment benefits	279.7	279.2
Other	47.8	49.5
Total deferred credits and other liabilities	922.3	914.5
Long-term Debt		
First refunding mortgage bonds of BGE	476.1	476.1
Other long-term debt of BGE	919.6	919.6
6.20% deferrable interest subordinated debentures due October 15, 2043 to wholly owned BGE Capital Trust II relating to trust preferred securities	257.7	257.7
Long-term debt of nonregulated businesses	25.0	25.0
Unamortized discount and premium	(3.8)	(4.1)
Current portion of long-term debt	(350.6)	(330.6)
Total long-term debt	1,324.0	1,343.7
Minority Interest	18.8	18.9
Preference Stock Not Subject to Mandatory Redemption	190.0	190.0
Common Shareholder's Equity		
Common stock	912.2	912.2
Retained earnings	603.9	574.7
Accumulated other comprehensive income	0.8	0.8
Total common shareholder's equity	1,516.9	1,487.7
Commitments, Guarantees, and Contingencies (see Notes)		
Total Liabilities and Equity	$ 4,769.6	$ 4,706.6

* *Unaudited*

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

CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

Baltimore Gas and Electric Company and Subsidiaries

Three Months Ended March 31,	2004	2003
	(In millions)	
Cash Flows From Operating Activities		
Net income	$ 76.0	$ 81.8
Adjustments to reconcile to net cash provided by operating activities		
Depreciation and amortization	60.7	56.7
Deferred income taxes	9.3	17.6
Investment tax credit adjustments	(0.5)	(0.5)
Deferred fuel costs	4.0	(24.9)
Pension and postemployment benefits	(26.5)	(73.5)
Allowance for equity funds used during construction	(0.5)	(0.9)
Changes in		
Accounts receivable	(4.3)	(33.8)
Receivables, affiliated companies	2.9	48.7
Materials, supplies, and fuel stocks	45.0	23.7
Other current assets	21.9	20.4
Accounts payable	(27.4)	22.6
Accounts payable, affiliated companies	37.4	(14.0)
Other current liabilities	15.8	45.1
Other	8.2	9.5
Net cash provided by operating activities	222.0	178.5
Cash Flows From Investing Activities		
Utility construction expenditures (excluding AFC)	(54.6)	(40.9)
Investment in cash pool at parent	(128.6)	(0.6)
Sales of investments and other assets	4.9	—
Net cash used in investing activities	(178.3)	(41.5)
Cash Flows From Financing Activities		
Distribution to parent	(43.5)	—
Repayment of long-term debt	—	(134.8)
Preference stock dividends paid	(3.3)	(3.3)
Net cash used in financing activities	(46.8)	(138.1)
Net Decrease in Cash and Cash Equivalents	(3.1)	(1.1)
Cash and Cash Equivalents at Beginning of Period	11.0	10.2
Cash and Cash Equivalents at End of Period	$ 7.9	$ 9.1

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

Various factors can have a significant impact on our results for interim periods. This means that the results for this quarter are not necessarily indicative of future quarters or full year results given the seasonality of our business.

Our interim financial statements on the previous pages reflect all adjustments that management believes are necessary for the fair presentation of the financial position and results of operations for the interim periods presented. These adjustments are of a normal recurring nature.

Basis of Presentation

This Quarterly Report on Form 10-Q is a combined report of Constellation Energy Group, Inc. (Constellation Energy) and Baltimore Gas and Electric Company (BGE). References in this report to "we" and "our" are to Constellation Energy and its subsidiaries, collectively. References in this report to the "regulated business(es)" are to BGE.

Earnings Per Share

Basic earnings per common share (EPS) is computed by dividing earnings applicable to common stock by the weighted-average number of common shares outstanding for the period. Diluted EPS reflects the potential dilution of common stock equivalent shares that could occur if securities or other contracts to issue common stock were exercised or converted into common stock. Our dilutive common stock equivalent shares consist of stock options of 1.1 million for the quarter ended March 31, 2004. There were no stock options excluded from the computation of diluted EPS for the quarter ended March 31, 2004. Stock options to purchase approximately 5.0 million shares during the quarter ended March 31, 2003 were not dilutive and were excluded from the computation of diluted EPS for that period.

Stock-Based Compensation

Under our long-term incentive plans, we granted stock options, performance and service-based restricted stock, and equity to officers, key employees, and members of the Board of Directors. As permitted by Statement of Financial Accounting Standards (SFAS) No. 123, *Accounting for Stock-Based Compensation*, we measure our stock-based compensation using the intrinsic value method in accordance with Accounting Principles Board Opinion (APB) No. 25, *Accounting for Stock Issued to Employees*, and related interpretations. We discuss these plans and accounting further in *Note 14* of our 2003 Annual Report on Form 10-K.

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

Quarter Ended March 31,	2004	2003
	(In millions, except per share amounts)	
Net income (loss), as reported	$66.2	$(131.4)
Add: Stock-based compensation expense determined under intrinsic value method and included in reported net income (loss), net of related tax effects	2.1	0.9
Deduct: Stock-based compensation expense determined under fair value based method for all awards, net of related tax effects	(3.6)	(3.0)
Pro-forma net income (loss)	$64.7	$(133.5)
Earnings (loss) per share:		
Basic – as reported	$0.39	$ (0.80)
Basic – pro forma	$0.38	$ (0.81)
Diluted – as reported	$0.39	$ (0.80)
Diluted – pro forma	$0.38	$ (0.81)

Accretion of Asset Retirement Obligations

SFAS No. 143, *Accounting for Asset Retirement Obligations*, provides the accounting requirements for recognizing an estimated liability for legal obligations associated with the retirement of tangible long-lived assets. We measure the liability at fair value when incurred and capitalize a corresponding amount as part of the book value of the related long-lived assets. The increase in the capitalized cost is included in determining depreciation expense over the estimated useful life of these assets. Since the fair value of the asset retirement obligations is determined using a present value approach, accretion of the liability due to the passage of time is recognized each period to "Accretion of asset retirement obligations" in our Consolidated Statements of Income until the settlement of the liability. We record a gain or loss when the liability is settled after retirement.

The change in our "Asset retirement obligations" liability during 2004 was as follows:

	(In millions)
Liability at January 1, 2004	$595.9
Accretion expense	11.2
Other	(2.0)
Liabilities incurred	—
Liabilities settled	—
Revisions to cash flows	—
Liability at March 31, 2004	$605.1

"Other" in the table above represents the asset retirement obligation associated with our geothermal facility in Hawaii that has been reclassified as a liability held for sale at March 31, 2004. We expect that at the time of the sale, the asset retirement obligation will be transferred to the buyer of the geothermal facility. We discuss the transfer of the geothermal facility assets and liabilities to held for sale in more detail in the *Loss from Discontinued Operations* section below.

Net Gain on Sales of Investments and Other Assets

2004

During the first quarter of 2004, our other nonregulated businesses recognized $1.5 million pre-tax, or $1.0 million after-tax, gains on the sale of non-core assets as follows:

- $1.1 million pre-tax gain on an installment sale of real estate, and
- $0.4 million pre-tax gain on the sale of a financial investment, as we continue to liquidate this operation.

2003

During the first quarter of 2003, our other nonregulated businesses recognized $13.7 million pre-tax, or $8.3 million after-tax, gains on the sale of non-core assets as follows:

- a $7.2 million pre-tax gain on the sale of an oil tanker to the U.S. Navy,
- a $5.3 million pre-tax gain on the favorable settlement of a contingent obligation we had previously reserved relating to the sale of our Guatemalan power plant operation in the fourth quarter of 2001, and
- a $1.2 million pre-tax gain on an installment sale of a parcel of real estate.

Loss from Discontinued Operations

In the fourth quarter of 2003, we began to re-evaluate our strategy regarding our geothermal generating facility in Hawaii. The reevaluation of our strategy included soliciting bids to determine the level of interest in the project. As of December 31, 2003, management determined that disposal of the project was more likely than not to occur. As a result, we evaluated our facility for impairment as of December 31, 2003, in accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, and determined that the assets were not impaired primarily due to indicative bids from third parties above the carrying value of the assets.

In March 2004, after reviewing final binding offers, management committed to a plan to sell the facility that met the "held for sale" criteria under SFAS No. 144. Under SFAS No. 144, we record assets and liabilities held for sale at the lesser of the carrying amount or fair value less cost to sell.

The fair value of the facility as of March 31, 2004, based on the bids under consideration was below carrying value, therefore, we recorded a $71.6 million pre-tax, or $47.3 million after-tax, impairment charge during the first quarter of 2004. We reported the after-tax impairment charge as a component of "Loss from discontinued operations" in our Consolidated Statements of Income.

Additionally we recognized the $1.5 million pre-tax, or $1.0 million after-tax, of earnings from the geothermal facility for the quarter ended March 31, 2004 as a component of "Loss from discontinued operations." We have not reclassified the prior year results of operations, which were reported under the equity method as "Nonregulated revenues" because we believe that reclassification of immaterial prior period results would be less useful than consistent reporting of prior year amounts. The geothermal facility had a $4.7 million net loss, including a $1.1 million cumulative effect of change in accounting principle for the adoption of SFAS No. 143, during the quarter ended March 31, 2003.

Presented in the table below are the components of the assets and liabilities held for sale which are included in our merchant energy business:

At March 31, 2004

	(In millions)
Assets held for sale	
Cash	$ 6.2
Accounts receivable	1.6
Property, plant and equipment	65.0
Other assets	14.8
Total	$87.6
Liabilities associated with assets held for sale	
Accounts payable	$ 0.3
Long-term debt	40.3
Asset retirement obligation	2.0
Other liabilities	4.9
Total	$47.5

On April 22, 2004, we executed a definitive agreement to sell the geothermal facility subject to standard closing conditions. We expect to record an additional loss on discontinued operations of approximately $4 million after-tax in the second quarter of 2004. The additional loss may vary from the current estimate based upon the actual sales price and costs to resolve remaining contingencies upon closing, which is expected to occur in mid-2004.

Information by Operating Segment

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

- Our nonregulated merchant energy business in North America includes:
  - fossil, nuclear, and hydroelectric generating facilities and interests in qualifying facilities, fuel processing facilities, and power projects in the United States,
  - origination of structured transactions (such as load-serving and power purchase agreements), and risk management services to various customers (including hedging of output from generating facilities and fuel costs),
  - electric and gas retail energy services to commercial and industrial customers, and
  - generation and consulting services.
- Our regulated electric business purchases, transmits, distributes, and sells electricity in Maryland.
- Our regulated gas business purchases, transports, and sells natural gas in Maryland.

Our remaining nonregulated businesses:

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

In addition, we own several investments that we do not consider to be core operations. These include financial investments, real estate projects, and interests in a Latin American power distribution project and in a fund that holds interests in two South American energy projects.

Our Merchant Energy, Regulated Electric, and Regulated Gas reportable segments are strategic businesses based principally upon regulations, products, and services that require different technology and marketing strategies. We evaluate the performance of these segments based on net income. We account for intersegment revenues using market prices. A summary of information by operating segment is shown in the table on the next page.

	Reportable Segments					
	Merchant Energy Business	Regulated Electric Business	Regulated Gas Business	Other Nonregulated Businesses	Eliminations	Consolidated
For the three months ended March 31,				*(In millions)*		
2004						
Unaffiliated revenues	$2,130.5	$484.4	$317.9	$103.8	$ —	$3,036.6
Intersegment revenues	254.3	—	1.6	—	(255.9)	—
Total revenues	2,384.8	484.4	319.5	103.8	(255.9)	3,036.6
Loss from discontinued operations	(46.3)	—	—	—	—	(46.3)
Net (loss) income	(6.8)	45.1	27.8	0.1	—	66.2
2003						
Unaffiliated revenues	$ 1,389.9	$ 486.3	$ 298.2	$ 155.6	$ —	$ 2,330.0
Intersegment revenues	287.2	—	5.3	—	(292.5)	—
Total revenues	1,677.1	486.3	303.5	155.6	(292.5)	2,330.0
Cumulative effects of changes in accounting principles	(198.4)	—	—	—	—	(198.4)
Net (loss) income	(218.9)	50.2	28.6	8.7	—	(131.4)

Pension and Postretirement Benefits

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

Three Months Ended March 31,	2004	2003
	(In millions)	
Components of net periodic pension benefit cost		
Service cost	$ 8.6	$ 8.8
Interest cost	19.3	21.3
Expected return on plan assets	(22.4)	(24.9)
Amortization of unrecognized prior service cost	1.3	1.5
Recognized net actuarial loss	3.5	1.3
Amount capitalized as construction cost	(0.7)	(0.9)
Net periodic pension benefit cost	$ 9.6	$ 7.1

We plan to contribute a total of between $50 million and $60 million to our qualified pension plans in 2004, even though there is no IRS required minimum contribution. We made a $50 million contribution on January 16, 2004.

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

Three Months Ended March 31,	2004	2003
	(In millions)	
Components of net periodic postretirement benefit cost		
Service cost	$ 1.3	$ 1.8
Interest cost	6.6	7.5
Amortization of transition obligation	0.6	0.6
Recognized net actuarial loss	2.0	1.6
Amortization of unrecognized prior service cost	(1.0)	(1.0)
Amount capitalized as construction cost	(2.4)	(2.1)
Net periodic postretirement benefit cost	$ 7.1	$ 8.4

Our non-qualified pension plans and our postretirement benefit programs are not funded, however we have trust assets securing certain executive pension benefits. We estimate that we will incur approximately $3 million in pension benefit payments for our non-qualified pension plans and approximately $30 million for retiree health and life insurance benefit payments during 2004.

Financing Activities

During the first quarter of 2004, we decided to continue our ownership in a synthetic fuel processing facility in South Carolina. We discuss this facility in more detail in the *Income Tax Credits* section below. In connection with our decision to continue with our ownership in this facility, we are committed to making fixed payments until the end of 2007. We have recorded a liability of $39.3 million in "Long-term debt" in our Consolidated Balance Sheets for these fixed payments.

Additionally, under our continuous offering program, employee benefit plans, and shareholder investment plans we issued $15.2 million of common stock during the quarter ended March 31, 2004.

Income Tax Credits

We have investments in facilities that manufacture solid synthetic fuel produced from coal as defined under Section 29 of the Internal Revenue Code for which we claim tax credits on our Federal income tax return. We recognize the tax benefit of these credits in our Consolidated Statements of Income when we believe it is highly probable that the credits will be sustained. The synthetic fuel process involves combining coal material with a chemical reagent to create a significant chemical change. A taxpayer may request a private letter ruling from the IRS to support its position that the synthetic fuel produced undergoes a significant chemical change and thus qualifies for Section 29 credits.

As of March 31, 2004, we have recognized cumulative tax benefits associated with Section 29 credits of $100.1 million, of which $22.1 million was recognized during the quarter ended March 31, 2004.

We own a minority ownership in four synthetic fuel facilities located in Ohio, Virginia, and West Virginia. These facilities have received private letter rulings from the IRS. In January 2004, the IRS concluded its examination of the partnership that owns these facilities for the tax years 1998 through 2001 and the IRS did not disallow any of the previously recognized synthetic fuel credits. We are awaiting final written notice of the resolution of the examination from the IRS.

In 2003, we purchased 99% ownership in a South Carolina facility that produces synthetic fuel. We did not recognize in our Consolidated Statements of Income the tax benefit of approximately $36 million for credits claimed on our South Carolina facility in 2003 pending receipt of a favorable private letter ruling. On January 12, 2004, we submitted our request for a private letter ruling to the IRS for our South Carolina facility.

In the first quarter of 2004, we implemented certain measures to mitigate our risk in the event that synthetic fuel tax credits associated with production at our South Carolina facility after January 1, 2004 were disallowed by the IRS. By mitigating our risk, we believe we obtained assurance that it is highly probable that the financial benefit of tax credits claimed in 2004 will be sustained. Accordingly, in the first quarter 2004, we recognized the tax benefit of $13.5 million for synthetic tax credits related to the 2004 production at our South Carolina facility.

On April 15, 2004, we received a favorable private letter ruling. We believe receipt of the private letter ruling provides assurance that it is highly probable that the credits will be sustained. Therefore, we expect to recognize the tax benefit of approximately $36 million of the credits claimed in 2003 in our Consolidated Statements of Income during the quarter ended June 30, 2004, the quarter in which we received the private letter ruling.

While we believe the production and sale of synthetic fuel from all of our synthetic fuel facilities meet the conditions to qualify for tax credits under Section 29 of the IRS Code, we cannot predict the timing or outcome of any future challenge by the IRS, legislative or regulatory action, or the ultimate impact of such events on the Section 29 credits that we have claimed to date or expect to claim in the future, but the impact could be material to our financial results.

Commitments, Guarantees, and Contingencies

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

- purchase of electric generating capacity and energy,
- procurement and delivery of fuels,
- the capacity and transmission and transportation rights for the physical delivery of energy to meet our obligations to our customers, and
- long-term service agreements, capital for construction programs and other.

Our merchant energy business has committed to long-term service agreements and other purchase commitments for our plants.

Our regulated gas business enters into various long-term contracts for the procurement, transportation, and storage of gas.

Our other nonregulated businesses have committed to gas purchases, as well as to contribute additional capital for construction programs and joint ventures in which they have an interest.

Corporately, we have committed to long-term service agreements and other obligations related to our information technology systems.

At March 31, 2004, the total amount of commitments was $4,178.4 million, which are primarily related to our merchant energy business.

Planned Acquisition

On November 25, 2003, we announced an agreement with Rochester Gas and Electric (RG&E) to acquire the R.E. Ginna Nuclear Power Plant (Ginna) located north of Rochester, New York. Upon closing the acquisition of this 495 MW facility, we will own and operate three nuclear power stations. We expect to acquire this facility in mid-2004.

The estimated purchase price for the Ginna plant is approximately $400 million, excluding approximately $22 million for purchased nuclear fuel. RG&E will transfer approximately $202 million in decommissioning funds at the time of closing. We believe this transfer will be sufficient to meet the decommissioning requirements of the facility.

The transaction is contingent upon regulatory approvals, including license extension. The acquisition includes a long-term unit contingent power purchase agreement where we will sell 90% of the plant's output and capacity to RG&E for 10 years at an average price of $44.00 per megawatt hour. The remaining 10% of the plant's output will be managed by our wholesale marketing and risk management operation and will be sold into the wholesale market.

Long-Term Power Sales Contracts

We enter into long-term power sales contracts in connection with our load-serving activities. We also enter into long-term power sales contracts associated with certain of our power plants. Our load-serving power sales contracts extend for terms through 2012 and provide for the sale of full requirements energy to electricity distribution utilities and certain retail customers. Our power sales contracts associated with our power plants extend for terms into 2011 and provide for the sale of all or a portion of the actual output of certain of our power plants. All long-term contracts were executed at pricing that approximated market rates, including profit margin, at the time of execution.

Guarantees

The terms of our guarantees are as follows:

	Expiration				
	2004	2005-2006	2007-2008	Thereafter	Total
	(In millions)				
Competitive Supply	$3,306.9	$495.0	$292.0	$ 498.1	$4,592.0
Other	9.9	11.6	—	863.7	885.2
Total	$3,316.8	$506.6	$292.0	$1,361.8	$5,477.2

At March 31, 2004, Constellation Energy had a total of $5,477.2 million guarantees outstanding related to loans, credit facilities, and contractual performance of certain of its subsidiaries as described below. These guarantees do not represent our incremental obligations and we do not expect to fund the full amount under these guarantees.

- Constellation Energy guaranteed $4,592.0 million on behalf of our subsidiaries for competitive supply activities. These guarantees are put into place in order to allow our subsidiaries the flexibility needed to conduct business with counterparties without having to post substantial cash collateral. While the face amount of these guarantees is $4,592.0 million, our calculated fair value of obligations covered by these guarantees was $1,125.8 million at March 31, 2004. If the parent company was required to fund subsidiary obligations, the total amount at current market prices is $1,125.8 million. The recorded fair value of obligations in our Consolidated Balance Sheets for these guarantees was $620.4 million at March 31, 2004.
- Constellation Energy guaranteed $552.2 million primarily on behalf of our nuclear facilities related to nuclear insurance and decommissioning.
- Constellation Energy guaranteed $34.7 million on behalf of our other nonregulated businesses primarily for loans and performance bonds of which $25.6 million was recorded in our Consolidated Balance Sheets at March 31, 2004.
- Our merchant energy business guaranteed $18.2 million for loans and other performance guarantees related to certain power projects in which we have an investment.
- Our other nonregulated business guaranteed $16.8 million for performance bonds.
- BGE guaranteed two-thirds of certain debt of Safe Harbor Water Power Corporation, an unconsolidated investment. At March 31, 2004, Safe Harbor Water Power Corporation had outstanding debt of $20.0 million. The maximum amount of BGE's guarantee is $13.3 million.
- BGE guaranteed the Trust Preferred Securities of $250.0 million of BGE Capital Trust II, an unconsolidated investment, as discussed in more detail in *Note 9* of our 2003 Annual Report on Form 10-K.

The total fair value of the obligations for our guarantees recorded in our Consolidated Balance Sheets was $646.0 million and not the $5.5 billion of total guarantees. We assess the risk of loss from these guarantees to be minimal.

Environmental Matters

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

- air quality,
- water quality, and
- treatment, storage, and disposal of solid and hazardous waste.

Clean Air Act

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

On October 27, 1998, the Environmental Protection Agency (EPA) issued a rule requiring 22 Eastern states and the District of Columbia to reduce emissions of NOx. The EPA rule requires states to implement controls sufficient to meet their NOx budget by May 30, 2004. However, the Northeast states decided to require compliance in 2003. Coal-fired power plants are a principal target of NOx reductions under this initiative.

Many of our generation facilities are subject to NOx reduction requirements under the EPA rule, including those located in Maryland and Pennsylvania. At the Brandon Shores and Wagner facilities, we installed emission reduction equipment for our coal-fired units to meet Maryland regulations issued pursuant to the EPA's rule. The owners of the Keystone plant in Pennsylvania completed the installation of emissions reduction equipment by July 2003 to meet Pennsylvania regulations issued pursuant to the EPA's rule. Our total cost of the emissions reduction equipment at the Keystone plant was approximately $37 million.

The EPA established new National Ambient Air Quality Standards for very fine particulates and revised standards for ozone. In April 2004, the EPA identified the areas that would be in ozone nonattainment for the new standards. The affected states will be required to submit plans for compliance within three years. While the new standards may require increased controls at some of our fossil generating plants in the future, planning and implementation of unit specific requirements will take place over the next several years. We cannot estimate the cost of these increased controls until the states and the EPA finalize their plans for meeting these standards.

We own several generating facilities in currently designated severe ozone nonattainment areas in Maryland and California. The Clean Air Act requires states to assess fees against every major stationary source of NOx and volatile organic chemicals in severe ozone nonattainment areas if national air quality standards are not achieved by a specified deadline. If implemented, the fee would be assessed based on the magnitude of a source's emissions as compared to its emissions when the area failed to meet the deadline. The exact method of computing these fees has not been established and will depend in part on state implementation regulations that have not been finalized.

The current deadline for most severe nonattainment areas is 2005, including those in which our generating facilities are located. Assessment of fees would commence in 2006 if the current effective date is maintained. However, there is significant uncertainty regarding the date when fees would be assessed in light of pending federal legislation and anticipated EPA rulemaking. Currently, we are unable to estimate the ultimate timing or financial impact of the standard in light of the uncertainty surrounding its effective date and the methodology that will be used in calculating the fees.

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

Based on the level of emissions control that the EPA and states are seeking in these new source review enforcement actions, we believe that material additional costs and penalties could be incurred, and planned capital expenditures could be accelerated, if the EPA was successful in any future actions regarding our facilities.

On October 27, 2003, the EPA's new source review rule on routine maintenance was published in the Federal Register. The new regulations would establish an equipment replacement cost threshold for determining when major new source review requirements are triggered. Plant owners may spend up to 20% of the replacement value of a generation unit on certain improvements each year without triggering requirements for new pollution controls. Parties had until December 26, 2003, the effective date of the rule, to appeal the agency's decision in court. An appeal was filed with the United States Court of Appeals. The effective date of the rule has been delayed pending review.

The Clean Air Act required the EPA to evaluate the public health impacts of emissions of mercury, a hazardous air pollutant, from coal-fired plants. The EPA decided to control mercury emissions from coal-fired plants. On December 15, 2003, the EPA proposed two alternatives for controlling mercury emissions from generating facilities. The EPA may require the installation of mercury reduction equipment. Alternatively, the EPA may revise standards to allow for the purchase of allowances. Compliance could be required as soon as 2007, or by 2010 depending on which alternative is selected. We believe final regulations could be issued in 2004 and could affect all oil-fired and coal-fired boilers. The cost of compliance with the final regulations could be material.

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

Clean Water Act

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

In April 2002, the EPA proposed rules under the Clean Water Act that require cooling water intake structures to reflect the best technology available for minimizing adverse environmental impacts. In February 2004, the proposed rules were finalized. The final rules require the installation of additional intake screens or other protective measures, as well as extensive site-specific study and monitoring requirements. We currently have five facilities affected by the regulation. The rule allows for a number of compliance options that will be assessed over the next four years. We are currently reviewing the final rules and their potential impact to us. Our compliance costs associated with the final rules could be material.

Under current provisions of the Clean Water Act, existing permits are renewed every five years, at which time permit limits come under extensive review and can be modified to account for more stringent regulations. In addition, the permits can be modified at any time. Changes to the water discharge permits of our coal or other fuel suppliers due to federal or state initiatives may increase the cost of fuel, which in turn could have a significant impact on our operations.

Waste Disposal

The EPA and several state agencies have notified us that we are considered a potentially responsible party with respect to the clean-up of certain environmentally contaminated sites owned and operated by others. We cannot estimate the clean-up costs for all of these sites.

However, based on a Record of Decision (ROD) issued by the EPA in 1997, we can estimate that BGE's current 15.47% share of the reasonably possible clean-up costs at one of these sites, Metal Bank of America, a metal reclaimer in Philadelphia, could be as much as $1.3 million higher than amounts we believe are probable and have recorded as a liability in our Consolidated Balance Sheets. There has been no significant regulatory activity with respect to actual site remediation since the EPA's ROD in 1997. EPA and the potentially responsible parties, including BGE, are currently pursuing claims against Metal Bank of America for an equitable share of expected site remediation costs.

In 1999, the EPA proposed to add the 68th Street Dump in Baltimore, Maryland to the Comprehensive Environmental Response, Compensation and Liability Act ("Superfund") National Priorities List ("NPL"), which is its list of sites targeted for clean-up and enforcement, and sent a general notice letter to BGE and 19 other parties identifying them as potentially liable parties at the 68th Street Dump site. In April 2003, EPA re-proposed the 68th Street site to the NPL, but decided not to include the site in its September 2003 update. We and other potentially responsible parties formed the 68th Street Coalition in March 2004 with the intent of entering into consent order negotiations with the EPA to investigate clean-up options for the site. At this stage, it is not possible to predict the outcome of those discussions or our share of the liability. However, the costs could have a material effect on our financial results.

In late December 1996, BGE signed a consent order with the Maryland Department of the Environment that required BGE to implement remedial action plans for contamination at and around the Spring Gardens site, located in Baltimore, Maryland. The Spring Gardens site was once used to manufacture gas from coal and oil. Based on the remedial action plans, the costs BGE considers to be probable to remedy the contamination are estimated to total $47 million. BGE recorded these costs as a liability in its Consolidated Balance Sheets and deferred these costs, net of accumulated amortization and amounts it recovered from insurance companies, as a regulatory asset. Because of the results of studies at this site, it is reasonably possible that additional costs could exceed the amount BGE recognized by approximately $14 million. Through March 31, 2004, BGE spent approximately $40 million for remediation at this site. BGE also investigated other small sites where gas was manufactured in the past. We do not expect the clean-up costs of the remaining smaller sites to have a material effect on our financial results.

The EPA issued its ROD for the Kane and Lombard Drum site located in Baltimore, Maryland on September 30, 2003. The ROD specifies the clean-up plan for the site, consisting of enhanced reductive dechlorination, a soil management plan, and institutional controls. The ROD was consistent with the proposed remedy the EPA released in December 2002. We expect the EPA to approach the potentially responsible parties regarding implementation of the plan in 2004. The total clean-up costs are estimated to be $7.3 million. We estimate our current share of site-related costs to be 11.1%. Our share of these future costs has not been determined and it may vary from the current estimate. In December 2002, we recorded a liability in our Consolidated Balance Sheets for our share of the clean-up costs that we believe is probable.

Nuclear Insurance

We maintain nuclear insurance coverage for Calvert Cliffs and Nine Mile Point in four program areas: liability, worker radiation, property, and accidental outage. These policies contain certain industry standard exclusions, including, but not limited to, ordinary wear and tear and war. We discuss our insurance programs in *Note 12* of our 2003 Annual Report on Form 10-K.

Non-nuclear Property Insurance

Our conventional property insurance provides coverage of $1.0 billion per occurrence for Certified acts of terrorism as defined under the Terrorism Risk Insurance Act. Certified acts of terrorism are determined by the Secretary of State and Attorney General of the United States and primarily are based upon the occurrence of significant acts of international terrorism. If a terrorist act occurs at any of our facilities, it could have a significant adverse impact on our financial results. We discuss our insurance programs in *Note 12* of our 2003 Annual Report on Form 10-K.

SFAS No. 133 Hedging Activities

We are exposed to market risk, including changes in interest rates and the impact of market fluctuations in the price and transportation costs of electricity, natural gas, and other commodities. We discuss our market risk in more detail on page 49.

Interest Rates

We use interest rate swaps to manage our interest rate exposures associated with new debt issuances. These swaps are designated as cash-flow hedges under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities, as amended*, with gains and losses, net of associated deferred income tax effects, recorded in "Accumulated other comprehensive income" in our Consolidated Balance Sheets, in anticipation of planned financing transactions. We reclassify gains and losses on the hedges from "Accumulated other comprehensive income" into "Interest expense" during the periods in which the interest payments being hedged occur.

At March 31, 2004, we have net unrealized pre-tax gains of $20.5 million related to interest rate hedges recorded in "Accumulated other comprehensive income." We expect to reclassify $2.9 million of pre-tax net gains on these swap contracts from "Accumulated other comprehensive income" into "Interest expense" during the next twelve months.

Commodity Prices

At March 31, 2004 our merchant energy business had designated certain purchase and sale contracts as cash-flow hedges of forecasted transactions for the years 2004 through 2011 under SFAS No. 133.

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

At March 31, 2004, our merchant energy business has net unrealized pre-tax gains of $134.5 million on these hedges recorded in "Accumulated other comprehensive income." We expect to reclassify $357.6 million of net pre-tax gains on cash-flow hedges from "Accumulated other comprehensive income" into earnings during the next twelve months based on the market prices at March 31, 2004. However, the actual amount reclassified into earnings could vary from the amounts recorded at March 31, 2004 due to future changes in market prices. We recognized into earnings a pre-tax gain of $9.3 million for the quarter ended March 31, 2004 and a pre-tax loss of $0.2 million for the quarter ended March 31, 2003 related to the ineffective portion of our hedges.

Accounting Standards Adopted

FIN 46R

In January 2003, the Financial Accounting Standards Board (FASB) issued Interpretation No. (FIN) 46, *Consolidation of Variable Interest Entities*, which was subsequently revised in its entirety with the issuance of FIN 46R in December 2003.

FIN 46R establishes conditions under which an entity must be consolidated based upon variable interests rather than voting interests. Variable interests are ownership interests or contractual relationships that enable the holder to share in the financial risks and rewards resulting from the activities of a Variable Interest Entity (VIE). A VIE can be a corporation, partnership, trust, or any other legal structure used for business purposes. An entity is considered a VIE under FIN 46R if it does not have an equity investment sufficient for it to finance its activities without assistance from variable interests or if its equity investors lack any of the following characteristics of a controlling financial interest:

- control through voting rights,
- obligation to absorb expected losses or
- right to receive expected residual returns.

FIN 46R requires us to consolidate VIEs for which we are the primary beneficiary and to disclose certain information about significant variable interests we hold. The primary beneficiary of a VIE is the entity that receives the majority of a VIE's expected losses, expected residual returns, or both.

FIN 46R was effective March 31, 2004 for all VIEs except special purpose entities (SPEs), for which the effective date was December 31, 2003. Therefore, at December 31, 2003, we and BGE deconsolidated BGE Capital Trust II, an SPE established to issue Trust Preferred Securities as described in *Note 9* of our 2003 Annual Report on Form 10-K because BGE is not the primary beneficiary. As a result, we currently record $257.7 million of Deferrable Interest Subordinated Debentures due to BGE Capital Trust II and $7.7 million equity investment in BGE Capital Trust II in "Other investments" in our and BGE's Consolidated Balance Sheets.

As a result of adopting the remainder of the provisions of FIN 46R as of March 31, 2004, we were not required to consolidate or deconsolidate any non-SPE entities with which we are involved through variable interests. We had preliminarily determined that we were the primary beneficiary for an unconsolidated investment in a hydroelectric generating plant located in Pennsylvania because our two-thirds voting interest is disproportionate to our 50% interest in the plant's earnings. However, we subsequently determined that the entity is not a VIE because less than substantially all of the plant's activities are conducted on our behalf, and therefore we do not have to consolidate the entity.

We have a significant interest in the following VIEs for which we are not the primary beneficiary:

VIE	Nature of Involvement	Date of Involvement
Power projects and fuel supply entities	Equity investment, Guarantees	Prior to 2003
Natural gas producing facility	Volumetric and price swap	July 2003

The following is summary information about these entities as of March 31, 2004:

	(In millions)
Total assets	$304
Total liabilities	161
Our ownership interest	40
Other ownership interests	103
Our maximum exposure to loss	125

The maximum exposure to loss represents the loss that we would incur in the unlikely event that our interests in all of these entities were to become worthless and we were required to fund the full amount of all guarantees associated with these entities. Our maximum exposure to loss as of March 31, 2004 consists of the following:

- the carrying amount of our investment totaling $41 million,
- debt and performance guarantees totaling $12 million, and
- volumetric and price variability of up to $72 million associated with a natural gas producer swap, based on contract volumes and gas prices as of March 31, 2004.

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

Related Party Transactions—BGE

Income Statement

BGE is providing standard offer service to customers at fixed rates over various time periods during the initial transition period from July 1, 2000 to June 30, 2006, for those customers that do not choose an alternate supplier. Our wholesale marketing and risk management operation is under contract to provide BGE the energy and capacity required to meet its standard offer service obligations for the transition period. The cost of BGE's purchased energy from nonregulated affiliates of Constellation Energy to meet its standard offer service obligation was $240.4 million for the quarter ended March 31, 2004 compared to $243.5 million for the same period in 2003.

In addition, Constellation Energy charges BGE for the costs of certain corporate functions. Certain costs are directly assigned to BGE. We allocate other corporate function costs based on a total percentage of expected use by BGE. Management believes this method of allocation is reasonable and approximates the cost BGE would have incurred as an unaffiliated entity. These costs were approximately $17.6 million for the quarter ended March 31, 2004 compared to $14.7 million for the quarter ended March 31, 2003.

Balance Sheet

BGE participates in a cash pool under a Master Demand Note agreement with Constellation Energy. Under this arrangement, participating subsidiaries may invest in or borrow from the pool at market interest rates. Constellation Energy administers the pool and invests excess cash in short-term investments or issues commercial paper to manage consolidated cash requirements. BGE had invested $358.8 million at March 31, 2004 and $230.2 million at December 31, 2003 under this arrangement.

Amounts related to corporate functions performed at the Constellation Energy holding company, BGE's purchases to meet its standard offer service obligation, BGE's charges to Constellation Energy and its nonregulated affiliates for certain services it provides them, and the participation of BGE's employees in the Constellation Energy pension plan result in intercompany balances in BGE's Consolidated Balance Sheets.

Management's Discussion and Analysis of Financial Condition and Results of Operations

Introduction and Overview

Constellation Energy Group, Inc. (Constellation Energy) is a North American energy company that conducts its business through various subsidiaries including a merchant energy business and Baltimore Gas and Electric Company (BGE). We describe our operating segments in the *Notes to Consolidated Financial Statements* on page 13.

This Quarterly Report on Form 10-Q is a combined report of Constellation Energy and BGE. References in this report to "we" and "our" are to Constellation Energy and its subsidiaries, collectively. References in this report to the "regulated business(es)" are to BGE.

Our merchant energy business is a competitive provider of energy solutions for large customers in North America. It has electric generation assets located in various regions of the United States and provides energy solutions to meet customers' needs. Our merchant energy business focuses on serving the full energy and capacity requirements (load-serving activities) of, and providing other risk management activities for various customers, such as utilities, municipalities, cooperatives, retail aggregators, and commercial and industrial customers. These load-serving activities typically occur in regional markets in which end-use customer electricity rates have been deregulated and thereby separated from the cost of generation supply.

Our wholesale marketing and risk management operation actively uses energy and energy-related commodities in order to manage our portfolio of energy purchases and sales to customers through structured transactions. As part of our risk management activities we trade power and gas to enable price discovery and facilitate the hedging of our load-serving and other risk management products and services. Within our trading function we allow limited risk-taking activities for profit. These activities are actively managed through daily value at risk and liquidity position limits. We discuss value at risk in more detail in the *Market Risk* section on page 49.

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

Our other nonregulated businesses:

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

In addition, we own several investments that we do not consider to be core operations. These include financial investments, real estate projects, and interests in a Latin American distribution project and in a fund that holds interests in two South American energy projects.

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

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

As you read this discussion and analysis, refer to our Consolidated Statements of Income on page 3, which present the results of our operations for the quarters ended March 31, 2004 and 2003. We analyze and explain the differences between periods in the specific line items of the Consolidated Statements of Income.

We have organized our discussion and analysis as follows:

- First, we discuss our strategy.
- We then describe the business environment in which we operate including how regulation, weather, and other factors affect our business.
- Next, we discuss our critical accounting policies. These are the accounting policies that are most important to both the portrayal of our financial condition and results and require management's most difficult, subjective or complex judgment.
- We highlight significant events that occurred in 2004 that are important to understanding our results of operations and financial condition.
- We then review our results of operations beginning with an overview of our total company results, followed by a more detailed review of those results by operating segment.
- We review our financial condition, addressing our sources and uses of cash, security ratings, capital resources, capital requirements, and commitments.
- We conclude with a discussion of our exposure to various market risks.

Strategy

We are pursuing a balanced strategy to distribute energy through our North American competitive supply activities and our regulated utility located in Maryland, BGE.

Our merchant energy business focuses on long-term, high-value sales of energy, capacity, and related products to large customers, including distribution utilities, municipalities, cooperatives, industrial customers, and commercial customers primarily in the regional markets in which end-use customer electricity rates have been deregulated and thereby separated from the cost of generation supply. These markets include:

- the New England, New York, and Mid-Atlantic regions,
- Texas,
- the Mid-West region,
- the West region, and
- certain areas in Canada.

We obtain this energy through both owned and contracted generation. Our generation fleet is strategically located in deregulated markets across the country and is diversified by fuel type, including nuclear, coal, gas, oil, and renewable sources. Where we do not own generation, we contract for power from other merchant providers, typically through power purchase agreements. We intend to remain diversified between regulated transmission and distribution and competitive supply. We will use both our owned generation and our contracted generation to support our competitive supply operation.

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

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

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

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

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

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

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

Beginning in the fourth quarter of 2001, we undertook a number of initiatives to reduce our costs towards competitive levels and to ensure that our resources are focused on our core energy businesses. These initiatives included the implementation of workforce reduction programs, the acceleration of our exit strategy for certain non-core assets, and the implementation of productivity initiatives.

We are constantly reevaluating our strategies and might consider:

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

Business Environment

With the shift toward customer choice, competition, and the growth of our merchant energy business, various factors affect our financial results. We discuss these various factors in the *Forward Looking Statements* section on page 54. We discuss our market risks in the *Market Risk* section on page 49.

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

Merchant Competition

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

Increased competition that resulted from some of these initiatives in several states contributed in some instances to a reduction in electricity prices and put pressure on electric utilities to lower their costs, including the cost of purchased electricity. Some states that were considering deregulation have slowed their plans or postponed consideration of deregulation. In addition, other states are reconsidering deregulation. Our merchant energy business is also affected by regional regulatory or legislative decisions, which may impact our financial results and our ability to successfully execute our growth strategy.

We believe there is adequate growth potential in the current deregulated market. However, in response to regional market differences and to promote competitive markets, the Federal Energy Regulatory Commission (FERC) proposed initiatives promoting the formation of Regional Transmission Organizations and a standard market design. If approved, these market changes could provide additional opportunities for our merchant energy business. We discuss these initiatives in the *FERC Regulation—Regional Transmission Organizations and Standard Market Design* section on page 26.

As the economy continues to recover and the market for commercial and industrial supply continues to grow, we have experienced increased competition in our retail commercial and industrial supply activities. The increase in retail competition may affect the margins that we will realize from our customers. However, we believe that our experience and expertise in assessing and managing risk will help us to remain competitive during volatile or otherwise adverse market circumstances.

Regulated Electric Competition

We are facing competition in the sale of electricity to retail customers.

Maryland

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

- All customers can choose their electric energy supplier. BGE provides fixed price standard offer service over various time periods for different classes of customers that do not select an alternative supplier until June 30, 2006.
- While BGE does not sell electric commodity to all customers in its service territory, BGE does deliver electricity to all customers and provides meter reading, billing, emergency response, regular maintenance, and balancing services.
- BGE provides a market rate standard offer service for those commercial and industrial customers who are no longer eligible for fixed price standard offer service.
- BGE residential base rates will not change before July 2006. While total residential base rates remain unchanged over the transition period (July 1, 2000 through June 30, 2006), annual standard offer service rate increases are offset by corresponding decreases in the competitive transition charge (CTC) that BGE receives from its customers.
- Commercial and industrial customers have several service options that will fix electric energy rates through June 30, 2004 and transition charges through June 30, 2006.

Standard Offer Service

Our wholesale marketing and risk management operation provides BGE with 100% of the energy and capacity required to meet its commercial and industrial standard offer service obligations through June 30, 2004, and 100% of the energy and capacity required to meet its residential standard offer service obligations through June 30, 2006. BGE will obtain its supply for standard offer service to its commercial and industrial customers beginning July 1, 2004, and will obtain its supply for standard offer service to its residential customers beginning July 1, 2006, through a competitive wholesale bidding process as discussed in the *Standard Offer Service—Provider of Last Resort (POLR)* section below.

Beginning July 1, 2002, the fixed price standard offer service rate ended for certain of our large commercial and industrial customers. As a result, the majority of these customers purchase their electricity from alternate suppliers, including subsidiaries of Constellation Energy. The remaining large commercial and industrial customers that continue to receive their electric supply from BGE are provided market rate standard offer service rates through June 30, 2004.

Beginning July 1, 2004, all commercial and industrial customers that receive their electric supply from BGE will be charged market-based standard offer service rates. Beginning July 1, 2006, BGE's current obligation to provide fixed price standard offer service to residential customers ends, and all residential customers that receive their electric supply from BGE will be charged market-based standard offer service rates.

Standard Offer Service—Provider of Last Resort (POLR)

In April 2003, the Maryland Public Service Commission (Maryland PSC) approved a settlement agreement reached by BGE and parties representing customers, industry, utilities, suppliers, the Maryland Energy Administration, the Maryland PSC's Staff, and the Office of People's Counsel which, among other things, extends BGE's obligation to supply standard offer service for a second transition period. Under the settlement agreement, BGE is obligated to provide market-based standard offer service to residential customers until June 30, 2010, and for commercial and industrial customers for one, two or four year periods beyond June 30, 2004, depending on customer load. The POLR rates charged during this time will recover BGE's wholesale power supply costs and include an administrative fee.

In September 2003, the Maryland PSC approved a second settlement agreement. This phase deals with the bid procurement process that utilities must follow to obtain wholesale power supply to serve retail customers on standard offer service during the second transition period. The settlement contained a model request for proposals, a model wholesale power supply contract, and various requirements pertaining to, among other things, bidder qualifications and bid evaluation criteria. Bidding to supply BGE's standard offer service to commercial and industrial customers beyond June 30, 2004 occurred through a multi-round competitive bidding process in February and March 2004. BGE executed one and two-year contracts for commercial and industrial electric power supply totaling approximately 2,300 megawatts.

Regulated Gas Competition

The wholesale price of natural gas is not subject to regulation. All BGE gas customers have the option to purchase gas from alternate suppliers.

Regulation by the Maryland PSC

In addition to electric restructuring, regulation by the Maryland PSC influences BGE's businesses. The Maryland PSC determines the rates that BGE can charge customers for the electric distribution and gas businesses. The Maryland PSC incorporates into BGE's electric rates the transmission rates determined by FERC. The rates for BGE's regulated gas business continue to consist of a "base rate" and a "fuel rate."

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

Electric Base Rates

BGE's electric rates are unbundled to show separate components for delivery service, competitive transition charges, standard offer services (generation), transmission, universal service, and certain taxes. As a result of the deregulation of electric generation in Maryland, BGE's residential electric base rates are frozen until June 30, 2006. Electric delivery service rates are frozen until June 30, 2004 for commercial and industrial customers. The generation and transmission components of rates are frozen for different time periods depending on the service options selected by those customers. We discuss the impact on base rates beyond 2004 in the *Regulated Electric Competition—Maryland* section on page 24.

Gas Base Rate
The base rate is the rate the Maryland PSC allows BGE to charge its customers for the cost of providing them service, plus a profit. Gas base rates are not affected by seasonal changes.

Gas Fuel Rate
BGE charges its gas customers separately for natural gas purchases. The price charged 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 42 and in *Note 1* of our 2003 Annual Report on Form 10-K.

FERC Regulation
Regional Transmission Organizations and Standard Market Design
In 1997, BGE turned over the operation of its transmission facilities to PJM, a power pool in the Mid-Atlantic region. In December 1999, FERC issued Order 2000, amending its regulations under the Federal Power Act to advance the formation of Regional Transmission Organizations (RTOs) that would allow easier access to transmission. PJM received FERC approval of its RTO status in December 2002 pending certain compliance filings.

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

In April 2003, the FERC issued a report that indicated its position with respect to the proposed rulemaking and announced that it intends to leave relatively unmodified existing RTO practices, to allow flexibility among regional approaches, to allow phased-in implementation of the final rule, and to provide an increased deference to states' concerns. Concurrently, proposed federal legislation has been introduced that would remand the rulemaking process to FERC, require the issuance of a new notice of proposed rulemaking, and delay the issuance of a final rule until at least January 1, 2007.

We believe that while the original SMD proposal would have led to uniform rules that would have been largely favorable to Constellation Energy and BGE, the revised regional approach should result in improved market operations across various regions. The proposed federal legislation does not appear to exclude a regional approach to market development. Overall, the trend continues to be toward increased competition in the regions. The region where BGE operates is expected to be relatively unaffected by this proceeding, based on current compliance by the PJM with the SMD proposal.

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

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

However, the Maryland PSC allows us to record a monthly adjustment to our regulated gas business revenues to eliminate the effect of abnormal weather patterns. We discuss this further in the *Weather Normalization* section on page 42.

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

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

We show the number of heating degree-days in the quarters ended March 31, 2004 and 2003, and the percentage change in the number of degree-days between these periods in the following table:

Quarter Ended March 31,	2004	2003
Heating degree-days	2,604	2,759
Percent change from prior period	(5.6)%	

Other Factors

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

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

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

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

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

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

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

Accounting Standards Adopted

We discuss recently adopted accounting standards in the *Notes to Consolidated Financial Statements* on page 20.

Critical Accounting Policies

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

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

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

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

Management believes the following accounting policies represent critical accounting policies as defined by the SEC. We discuss our significant accounting policies, including those that do not require management to make difficult, subjective, or complex judgments or estimates, in *Note 1* of our 2003 Annual Report on Form 10-K.

Revenue Recognition—Mark-to-Market Method of Accounting

Our merchant energy business enters into contracts for energy, other energy-related commodities, and related derivatives. We record merchant energy business revenues using two methods of accounting: accrual accounting and mark-to-market accounting. We describe our use of accrual accounting (including hedge accounting) in more detail in *Note 1* of our 2003 Annual Report on Form 10-K.

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

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

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

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

- Close-out reserve—this reserve represents the estimated cost to close out or sell to a third-party open mark-to-market positions. This reserve has the effect of valuing "long" positions at the bid price and "short" positions at the offer price. We compute this reserve using a market-based estimate of the bid/offer spread for each commodity and option price and the absolute quantity of our net open positions for each year. To the extent that we are not able to obtain market information for similar contracts, the close-out reserve is equivalent to the initial contract margin, thereby resulting in no gain or loss at inception. The level of total close-out reserves increases as we have larger unhedged positions, bid-offer spreads increase, or market information is not available, and it decreases as we reduce our unhedged positions, bid-offer spreads decrease, or market information becomes available.
- Credit-spread adjustment—for risk management purposes, we compute the value of our mark-to-market energy assets and liabilities using a risk-free discount rate. In order to compute fair value for financial reporting purposes, we adjust the value of our mark-to-market energy assets to reflect the credit-worthiness of each counterparty based upon published credit ratings, where available, or equivalent internal credit ratings and associated default probability percentages. We compute this reserve by applying the appropriate default probability percentage to our outstanding credit exposure, net of collateral, for each counterparty. The level of this reserve increases as our credit exposure to counterparties increases, the maturity terms of our transactions increase, or the credit ratings of our counterparties deteriorate, and it decreases when our credit exposure to counterparties decreases, the maturity terms of our transactions decrease, or the credit ratings of our counterparties improve.

Market prices for energy and energy-related commodities vary based upon a number of factors, and changes in market prices affect both the recorded fair value of our mark-to-market energy contracts and the level of future revenues and costs associated with accrual-basis activities. Changes in the value of our mark-to-market energy contracts will affect our earnings in the period of the change, while changes in forward market prices related to accrual-basis revenues and costs will affect our earnings in future periods to the extent those prices are realized. We cannot predict whether, or to what extent, the factors affecting market prices may change, but those changes could be material and could affect us either favorably or unfavorably. We discuss our market risk in more detail in the *Market Risk* section on page 49.

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

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

We discuss the impact of mark-to-market accounting on our financial results in the *Results of Operations—Merchant Energy Business* section on page 34.

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

Long-Lived Assets

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

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

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

In order to estimate an asset's future cash flows, we consider historical cash flows, as well as reflect our understanding of the extent to which future cash flows will be either similar to or different from past experience based on all available evidence. To the extent applicable, the assumptions we use are consistent with forecasts that we are otherwise required to make (for example, in preparing our other earnings forecasts). If we are considering alternative courses of action to recover the carrying amount of a long-lived asset (such as the potential sale of an asset), we probability-weight the alternative courses of action to estimate the cash flows.

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

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

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

as discussed on the previous page with respect to undiscounted cash flows. Actual future market prices and project costs could vary from those used in our estimates, and the impact of such variations could be material.

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

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

Goodwill

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

Asset Retirement Obligations

We incur legal obligations associated with the retirement of certain long-lived assets. SFAS No. 143, *Accounting for Asset Retirement Obligations*, provides the accounting for legal obligations associated with the retirement of long-lived assets. We incur such legal obligations as a result of environmental and other government regulations, contractual agreements, and other factors. The application of this standard requires significant judgment due to the large number and diverse nature of the assets in our various businesses and the estimation of future cash flows required to measure legal obligations associated with the retirement of specific assets.

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

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

Events of 2004

Loss from Discontinued Operations

In the fourth quarter of 2003, we began to re-evaluate our strategy regarding our geothermal generating facility in Hawaii. The reevaluation of our strategy included soliciting bids to determine the level of interest in the project. As of December 31, 2003, management had determined that disposal of the project was more likely than not to occur. As a result, we evaluated our facility for impairment as of December 31, 2003, in accordance with SFAS No. 144, and determined that the assets were not impaired primarily due to indicative bids from third parties above the carrying value of the assets.

In March 2004, after reviewing final binding offers, management committed to a plan to sell the facility that met the "held for sale" criteria under SFAS No. 144. Under SFAS No. 144, we record assets and liabilities held for sale at the lesser of the carrying amount or fair value less cost to sell.

The fair value of the facility as of March 31, 2004, based on the bids under consideration was below carrying value, therefore, we recorded a $71.6 million pre-tax, or $47.3 million after-tax, impairment charge during the first quarter of 2004. We reported the after-tax impairment charge as a component of "Loss from discontinued operations" in our Consolidated Statements of Income.

Additionally we recognized the $1.5 million pre-tax, or $1.0 million after-tax, of earnings from the geothermal facility for the quarter ended March 31, 2004 as a component of "Loss from discontinued operations." We have not reclassified the prior year results of operations, which were reported under the equity method as "Nonregulated revenues" because we believe that reclassification of immaterial prior period results would be less useful than consistent reporting of prior year amounts. The geothermal facility had a $4.7 million net loss, including a $1.1 million cumulative effect of change in accounting principle for the adoption of SFAS No. 143, during the quarter ended March 31, 2003.

Presented in the table below are the components of the assets and liabilities held for sale which are included in our merchant energy business:

At March 31, 2004

	(In millions)
Assets held for sale	
Cash	$ 6.2
Accounts receivable	1.6
Property, plant, and equipment	65.0
Other assets	14.8
Total	$87.6
Liabilities associated with assets held for sale	
Accounts payable	$ 0.3
Long-term debt	40.3
Asset retirement obligation	2.0
Other liabilities	4.9
Total	$47.5

On April 22, 2004, we executed a definitive agreement to sell the geothermal facility subject to standard closing conditions. We expect to record an additional loss on discontinued operations of approximately $4 million after-tax in the second quarter of 2004. The additional loss may vary from the current estimate based upon the actual sales price and costs to resolve remaining contingencies upon closing, which is expected in mid-2004.

Synthetic Fuel Tax Credits

We have investments in facilities that manufacture solid synthetic fuel produced from coal as defined under Section 29 of the Internal Revenue Code for which we claim tax credits on our Federal income tax return. We recognize the tax benefit of these credits in our Consolidated Statements of Income when we believe it is highly probable that the credits will be sustained. The synthetic fuel process involves combining coal material with a chemical reagent to create a significant chemical change. A taxpayer may request a private letter ruling from the IRS to support its position that the synthetic fuel produced undergoes a significant chemical change and thus qualifies for Section 29 credits.

As of March 31, 2004, we have recognized cumulative tax benefits associated with Section 29 credits of $100.1 million, of which $22.1 million was recognized during the quarter ended March 31, 2004.

We own a minority ownership in four synthetic fuel facilities located in Ohio, Virginia, and West Virginia. These facilities have received private letter rulings from the IRS. In January 2004, the IRS concluded its examination of the partnership that owns these facilities for the tax years 1998 through 2001 and the IRS did not disallow any of the previously recognized synthetic fuel credits. We are awaiting final written notice of the resolution of the examination from the IRS.

In 2003, we purchased 99% ownership in a South Carolina facility that produces synthetic fuel. We did not recognize in our Consolidated Statements of Income the tax benefit of approximately $36 million for credits claimed on our South Carolina facility in 2003 pending receipt of a favorable private letter ruling. On January 12, 2004, we submitted our request for a private letter ruling to the IRS for our South Carolina facility.

In the first quarter of 2004, we implemented certain measures to mitigate our risk in the event that synthetic fuel tax credits associated with production at our South Carolina facility after January 1, 2004 were disallowed by the IRS. By mitigating our risk, we believe we obtained assurance that it is highly probable that the financial benefit of tax credits claimed in 2004 will be sustained. Accordingly, in the first quarter 2004, we recognized the tax benefit of $13.5 million for synthetic tax credits related to the 2004 production of our South Carolina facility.

On April 15, 2004 we received a favorable private letter ruling. We believe receipt of the private letter ruling provides assurance that it is highly probable that the credits will be sustained. Therefore, we expect to recognize the tax benefit of approximately $36 million of the credits claimed in 2003 in our Consolidated Statements of Income during the quarter ended June 30, 2004, the quarter in which we received the private letter ruling.

While we believe the production and sale of synthetic fuel from all of our synthetic fuel facilities meet the conditions to qualify for tax credits under Section 29 of the IRS Code, we cannot predict the timing or outcome of any future challenge by the IRS, legislative or regulatory action, or the ultimate impact of such events on the Section 29 credits that we have claimed to date or expect to claim in the future, but the impact could be material to our financial results.

Gains on Sale of Investments and Other Assets

During the first quarter of 2004, our other nonregulated businesses recognized $1.5 million of pre-tax gains on the sales of non-core assets as follows:

- $1.1 million pre-tax gain on an installment sale of real estate, and
- $0.4 million pre-tax gain on the sale of financial investments, as we continue to liquidate this operation.

Dividend Increase

In January 2004, we announced an increase in our quarterly dividend to 28.5 cents per share on our common stock payable April 1, 2004 to holders of record on March 10, 2004. This is equivalent to an annual rate of $1.14 per share. Previously, our quarterly dividend on our common stock was 26 cents per share, equivalent to an annual rate of $1.04 per share.

Planned Acquisition

On November 25, 2003, we announced an agreement with Rochester Gas and Electric (RG&E) to acquire the R.E. Ginna Nuclear Power Plant (Ginna) located north of Rochester, New York. Upon closing the acquisition of this 495 MW facility, we will own and operate three nuclear power stations. We expect to acquire this facility in mid-2004.

The estimated purchase price for the Ginna plant is approximately $400 million, excluding approximately $22 million for purchased nuclear fuel. RG&E will transfer approximately $202 million in decommissioning funds at the time of closing. We believe this transfer will be sufficient to meet the decommissioning requirements of the facility.

The transaction is contingent upon regulatory approvals, including license extension. The acquisition includes a long-term unit contingent power purchase agreement where we will sell 90% of the plant's output and capacity to RG&E for 10 years at an average price of $44.00 per megawatt hour. The remaining 10% of the plant's output will be managed by our wholesale marketing and risk management operation and will be sold into the wholesale market.

Results of Operations for the Quarter Ended March 31, 2004 Compared with the Same Period of 2003

In this section, we discuss our earnings and the factors affecting them. We begin with a general overview, then separately discuss earnings for our operating segments. Changes in other income, fixed charges, and income taxes are discussed, as necessary, in the aggregate for all segments in the *Consolidated Nonoperating Income and Expenses* section on page 43.

Overview

Results

Quarter Ended March 31,	2004	2003
	(In millions, after tax)	
Merchant energy	$ 39.5	$ (20.5)
Regulated electric	45.1	50.2
Regulated gas	27.8	28.6
Other nonregulated	0.1	8.7
Income from Continuing Operations and Before Cumulative Effects of Changes in Accounting Principles	112.5	67.0
Loss from Discontinued Operations (see Notes)	(46.3)	—
Cumulative Effects of Changes in Accounting Principles	—	(198.4)
Net Income (Loss)	$ 66.2	$(131.4)
Special Items Included in Operations		
Gains on sale of investments and other assets	$ 1.0	$ 8.3

Quarter Ended March 31, 2004

Our total net income for the quarter ended March 31, 2004 increased $197.6 million, or $1.19 per share, compared to the same period of 2003 mostly because of the following:

- We recorded a $266.1 million after-tax, or $1.61 per share, loss for the cumulative effect of adopting Emerging Issues Task Force (EITF) Issue 02-3, *Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities*. This was partially offset by a $67.7 million after-tax, or $0.41 per share, gain for the cumulative effect of adopting SFAS No. 143. These items had a combined negative impact during the first quarter of 2003.
- We had higher earnings from our nuclear generating assets due to reduced outage days at our Calvert Cliffs nuclear power plant that began replacement of the steam generator for Unit 2 during the first quarter of 2003, partially offset by lower earnings at our Nine Mile Point facility primarily associated with our planned January 2004 outage.
- We had higher earnings from our competitive supply activities mostly due to the growth in that business.
- We had higher earnings due to the absence of losses of approximately $12 million associated with economic hedges that did not qualify for cash-flow hedge accounting treatment in 2003. We also had higher earnings due to the positive impact of approximately $6 million related to hedge ineffectiveness during the first quarter of 2004.
- We had higher earnings of $13.5 million due to the High Desert Power Project that commenced operations in April 2003.
- We had higher earnings of $7.4 million primarily due to the recognition of tax credits associated with the 2004 production at our South Carolina synfuel facility.

These increases were partially offset by the following:

- We recorded a $46.3 million after-tax, or $0.27 per share, loss from discontinued operations.
- We had higher benefit and other inflationary costs.
- We had lower earnings from our regulated electric business mostly because of milder winter weather in the central Maryland region and higher operating expenses in the first quarter of 2004.
- We recognized a gain of $8.3 million after-tax, or $0.05 per share, related to non-core asset sales in the first quarter of 2003 that had a favorable impact in that period.

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

Merchant Energy Business

Background

Our merchant energy business is a competitive provider of energy solutions for large customers in North America. We discuss the impact of deregulation on our merchant energy business in the *Business Environment—Electric Competition* section of our 2003 Annual Report on Form 10-K.

We record merchant energy revenues and expenses in our financial results in different periods depending upon which portion of our business they affect. We discuss our revenue recognition policies in the *Critical Accounting Policies* section on page 28 and in *Note 1* of our 2003 Annual Report on Form 10-K. We summarize our policies as follows:

- We record revenues as they are earned and fuel and purchased energy costs as they are incurred for contracts and activities subject to accrual accounting, including certain load-serving activities.
- Prior to the settlement of the forecasted transaction being hedged, we record changes in the fair value of contracts designated as cash-flow hedges in other comprehensive income to the extent that the hedges are effective. We record the effective portion of the changes in fair value of hedges in earnings in the period the settlement of the hedged transaction occurs. We record the ineffective portion of the changes in fair value of hedges, if any, in earnings in the period in which the change occurs.
- We record changes in the fair value of contracts that are subject to mark-to-market accounting in revenues on a net basis in the period in which the change occurs.

Mark-to-market accounting requires us to make estimates and assumptions using judgment in determining the fair value of our contracts and in recording revenues from those contracts. We discuss the effects of mark-to-market accounting on our revenues in the *Competitive Supply—Mark-to-Market Revenues* section on page 36. We discuss mark-to-market accounting and the accounting policies for the merchant energy business further in the *Critical Accounting Policies* section on page 28 and in *Note 1* of our 2003 Annual Report on Form 10-K.

Results

Quarter Ended March 31,	2004	2003
	(In millions)	
Revenues	$ 2,384.8	$ 1,677.1
Fuel and purchased energy expenses	(1,947.7)	(1,390.1)
Operations and maintenance expenses	(273.1)	(213.3)
Depreciation and amortization	(55.7)	(50.9)
Accretion of asset retirement obligations	(11.2)	(10.7)
Taxes other than income taxes	(21.8)	(22.1)
Income (Loss) from Operations	$ 75.3	$ (10.0)
Income (Loss) from Continuing Operations and Before Cumulative Effects of Changes in Accounting Principles (after-tax)	$ 39.5	$ (20.5)
Loss from Discontinued Operations (after-tax)	(46.3)	—
Cumulative Effects of Changes in Accounting Principles (after-tax)	—	(198.4)
Net Loss	$ (6.8)	$ (218.9)

Above amounts include intercompany transactions eliminated in our Consolidated Financial Statements. The Information by Operating Segments section within the Notes to Consolidated Financial Statements on page 14 provides a reconciliation of operating results by segment to our Consolidated Financial Statements.

Revenues and Fuel and Purchased Energy Expenses

Our merchant energy business manages our costs of procuring fuel and energy and revenues we realize from the sale of energy to our customers. The difference between revenues and fuel and purchased energy expenses is the primary driver of the profitability of our merchant energy business. Accordingly, we believe it is appropriate to discuss the operating results of our merchant energy business by analyzing the changes in the relationship between revenues and fuel and purchased energy expenses. In managing our portfolio, we occasionally terminate, restructure, or acquire contracts. Such transactions are within the normal course of managing our portfolio and may materially impact the timing of our recognition of revenues and fuel and purchased energy expenses.

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

- Mid-Atlantic Fleet—our fossil, nuclear, and hydroelectric generating facilities and load-serving activities in the PJM region for which the output is primarily used to serve BGE. This also includes active portfolio management of the generating assets and associated physical and financial arrangements.
- Plants with Power Purchase Agreements—our generating facilities with long-term power purchase agreements, including our Nine Mile Point Nuclear Station (Nine Mile Point), Oleander, University Park, and High Desert facilities.
- Competitive Supply—our wholesale marketing and risk management operation that provides energy products and services to distribution utilities and other wholesale customers. We also provide electric and gas energy services to retail commercial and industrial customers.
- Other—our investments in qualifying facilities and domestic power projects and our generation and consulting services.

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

Quarter Ended March 31,	2004	2003
	(Dollar amounts in millions)	
Revenues:		
Mid-Atlantic Fleet	$ 431.3	$ 375.7
Plants with Power Purchase Agreements	133.8	109.2
Competitive Supply	1,799.5	1,177.1
Other	20.2	15.1
Total	$ 2,384.8	$ 1,677.1
Fuel and purchased energy expenses:		
Mid-Atlantic Fleet	$ (227.5)	$ (205.5)
Plants with Power Purchase Agreements	(10.5)	(12.7)
Competitive Supply	(1,709.7)	(1,171.9)
Other	—	—
Total	$(1,947.7)	$(1,390.1)

Revenues less fuel and purchased energy expenses:		% of Total		% of Total
Mid-Atlantic Fleet	$ 203.8	47%	$ 170.2	59%
Plants with Power Purchase Agreements	123.3	28	96.5	34
Competitive Supply	89.8	20	5.2	2
Other	20.2	5	15.1	5
Total	$ 437.1	100%	$ 287.0	100%

Mid-Atlantic Fleet

Quarter Ended March 31,	2004	2003
	(In millions)	
Revenues	$ 431.3	$ 375.7
Fuel and purchased energy expenses	(227.5)	(205.5)
Revenues less fuel and purchased energy	$ 203.8	$ 170.2

Revenues

BGE Standard Offer Service

The majority of Mid-Atlantic Fleet revenues arise from supplying BGE's standard offer service requirements. Revenues from supplying BGE's standard offer service requirements, including CTC and decommissioning revenues, were about the same in 2004 compared to 2003.

CTC revenues are impacted by the CTC rates our merchant energy business receives from BGE customers as well as the volumes delivered to BGE customers. The CTC rates decline over the transition period as previously discussed in the *Regulated Electric Competition—Maryland* section on page 24.

During 2003, our merchant energy business provided the energy to meet the requirements of large commercial and industrial customers that had left BGE's standard offer service and elected BGE Home as their electric generation supplier. Revenues from BGE Home were $19.5 million in the first quarter of 2003, which had a positive impact in that period. As these customer contracts expired during 2003, any renewal was with our commercial and industrial retail marketing operation and the results are included in our Competitive Supply category.

Other Mid-Atlantic Fleet Revenues

Other merchant energy revenues in the PJM region increased $75.1 million in 2004 compared to 2003 mostly because of:

- $36.0 million related to load-serving transactions in New Jersey that began in mid-2003,
- $34.4 million related to higher prices for sales of our unhedged owned generation in excess of that used to serve BGE's standard offer service, including the higher generation at our Calvert Cliffs facility due to the absence of a planned outage during the first quarter of 2004, and
- higher sales of natural gas at higher prices.

Fuel and Purchased Energy Expenses
Our merchant energy business had higher fuel and purchased energy expenses in the Mid-Atlantic Fleet in 2004 compared to 2003 primarily due to higher generation at our plants and increased purchased energy and capacity expenses because of higher wholesale market prices.

Plants with Power Purchase Agreements

Quarter Ended March 31,	2004	2003
	(In millions)	
Revenues	$133.8	$109.2
Fuel and purchased energy expenses	(10.5)	(12.7)
Revenues less fuel and purchased energy	$123.3	$ 96.5

The increase in revenues in 2004 compared to 2003 was primarily due to revenues of $38.5 million from the High Desert Power Project which commenced operations in the second quarter of 2003. This increase was offset in part by lower revenues of $14.3 million at our Nine Mile Point facility mostly because of lower availability of the plant due to our planned January outage during 2004 and higher power prices in the first quarter of 2003 that had a positive impact in that period.

Competitive Supply

Quarter Ended March 31,	2004	2003
	(In millions)	
Accrual revenues	$ 1,791.3	$ 1,180.3
Mark-to-market revenues	8.2	(3.2)
Fuel and purchased energy expenses	(1,709.7)	(1,171.9)
Revenues less fuel and purchased energy	$ 89.8	$ 5.2

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

Accrual Revenues and Fuel and Purchased Energy Expenses
Our accrual revenues and fuel and purchased energy expenses increased in 2004 compared to 2003 mostly because of increased retail sales to commercial and industrial customers. This increase in sales of approximately $400 million is primarily due to high customer renewal rates, portfolio acquisitions during 2003, the acquisitions of Blackhawk and Kaztex in October 2003, and the positive impact of hedge ineffectiveness during the first quarter of 2004.

Additionally, our wholesale marketing and risk management operation had higher sales of approximately $200 million, primarily in Texas, New England, and Mid-West. The higher sales in the Texas and New England regions are primarily due to our growth in these regions. The higher sales in the Mid-West are primarily due to the portfolio acquisition from CMS Energy Corp., which occurred in the second quarter of 2003.

Mark-to-Market Revenues
Mark-to-market revenues include net gains and losses from origination and risk management activities for which we use the mark-to-market method of accounting. We discuss these activities and the mark-to-market method of accounting in more detail in the *Critical Accounting Policies* section on page 28.

As a result of the nature of our operations and the use of mark-to-market accounting for certain activities, mark-to-market revenues and earnings will fluctuate. We cannot predict these fluctuations, but the impact on our revenues and earnings could be material. We discuss our market risk in more detail in the *Market Risk* section on page 49. The primary factors that cause fluctuations in our mark-to-market revenues and earnings are:

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

Mark-to-market revenues were as follows:

Quarter Ended March 31,	2004	2003
	(In millions)	
Unrealized revenues		
Origination transactions	$ —	$ 14.2
Risk management		
Unrealized changes in fair value	8.2	(17.4)
Changes in valuation techniques	—	—
Reclassification of settled contracts to realized	(15.0)	(44.0)
Total risk management	(6.8)	(61.4)
Total unrealized revenues	(6.8)	(47.2)
Realized revenues	15.0	44.0
Total mark-to-market revenues	$ 8.2	$ (3.2)

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

Origination gains represent the initial fair value recognized on these structured transactions. The recognition of origination gains is dependent on the existence of observable market data that validates the initial fair value of the contract. For the quarter ended March 31, 2004, we did not realize any origination gains.

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

Risk management revenues represent both realized and unrealized gains and losses from changes in the value of our entire portfolio. We discuss the changes in mark-to-market revenues below. We show the relationship between our revenues and the change in our net mark-to-market energy asset later in this section.

Our mark-to-market revenues are affected by the portion of our activities that are subject to mark-to-market accounting. Beginning January 1, 2003, under EITF 02-3, we do not record non-derivative contracts at fair value. Further, to the extent that we are not able to observe quoted market prices or other current market transactions for derivative contract values determined using models, we record a reserve to adjust such contracts to result in zero gain or loss at inception. We remove the reserve and record such contracts at fair value when we obtain current market information for contracts with similar terms and counterparties.

Mark-to-market revenues increased $11.4 million during 2004 compared to 2003 mostly because of lower net losses from risk management activities compared to the prior year. The increase in risk management revenues is primarily due to mark-to-market losses on hedges that did not qualify for hedge accounting treatment during 2003 that had a negative impact in that period as discussed in more detail below, offset in part by higher origination gains in 2003.

With the implementation of EITF 02-3 in the first quarter of 2003, all of our load-serving contracts were converted to accrual accounting. However, several economically effective hedges on these positions did not qualify for hedge accounting treatment under SFAS No. 133 and remained in the mark-to-market portfolio.

In the first quarter of 2003, increasing forward prices shifted value between accrual load-serving positions and associated mark-to-market hedges producing a timing difference in the recognition of earnings on related transactions. As a result, we recorded a $19.8 million pre-tax loss on the mark-to-market hedges in the first quarter of 2003.

Mark-to-Market Energy Assets and Liabilities

Our mark-to-market energy assets and liabilities are comprised of derivative contracts and consisted of the following:

	March 31, 2004	December 31, 2003
	(In millions)	
Current Assets	$569.5	$488.3
Noncurrent Assets	343.5	261.9
Total Assets	913.0	750.2
Current Liabilities	544.3	474.6
Noncurrent Liabilities	355.1	258.0
Total Liabilities	899.4	732.6
Net mark-to-market energy asset	$ 13.6	$ 17.6

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

Change in Net Mark-to-Market Asset

	(In millions)	
Fair value beginning of period		$ 17.6
Changes in fair value recorded as revenues		
Origination gains	$ —	
Unrealized changes in fair value	8.2	
Changes in valuation techniques	—	
Reclassification of settled contracts to realized	(15.0)	
Total changes in fair value recorded as revenues		(6.8)
Changes in value of exchange-listed futures and options		(16.6)
Net change in premiums on options		9.8
Other changes in fair value		9.6
Fair value at end of year		$ 13.6

Components of changes in the net mark-to-market energy asset that affected revenues include:

- Origination gains representing the initial unrealized fair value at the time these contracts are executed to the extent permitted by applicable accounting rules.
- Unrealized changes in fair value representing unrealized changes in commodity prices, the volatility of options on commodities, the time value of options, and other valuation adjustments.
- Changes in valuation techniques representing improvements in estimation techniques, including modeling and other statistical enhancements used to value our portfolio to more accurately reflect the economic value of our contracts.
- Reclassification of settled contracts to realized representing the portion of previously unrealized amounts settled during the period and recorded as realized revenues.

The net mark-to-market energy asset also changed due to the following items recorded in accounts other than revenue:

- Changes in value of exchange-listed futures and options are adjustments to remove unrealized revenue from exchange-traded contracts that are included in risk management revenues. The fair value of these contracts is recorded in "Accounts receivable" rather than "Mark-to-market energy assets" in our Consolidated Balance Sheets because these amounts are settled through our margin account with a third-party broker.
- Net changes in premiums on options reflects the accounting for premiums on options purchased as an increase in the net mark-to-market energy asset and premiums on options sold as a decrease in the net mark-to-market energy asset.

The settlement terms of the net mark-to-market energy asset and sources of fair value as of March 31, 2004 are as follows:

	Settlement Term							
	2004	2005	2006	2007	2008	2009	Thereafter	Fair Value
	(In millions)							
Prices provided by external sources (1)	$8.6	$(9.1)	$ 71.5	$0.1	$ —	$ —	$ —	$ 71.1
Prices based on models	0.6	4.2	(60.9)	8.7	(3.5)	(2.7)	(3.9)	(57.5)
Total net mark-to-market energy asset	$9.2	$(4.9)	$ 10.6	$8.8	$(3.5)	$(2.7)	$(3.9)	$ 13.6

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

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

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

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

- forward purchases and sales of electricity during peak and off-peak hours for delivery terms primarily through 2005, but up to 2007, depending upon the region,
- options for the purchase and sale of electricity during peak hours for delivery terms through 2005, depending upon the region,
- forward purchases and sales of electric capacity for delivery terms through 2005,
- forward purchases and sales of natural gas, coal and oil for delivery terms through 2006, and
- options for the purchase and sale of natural gas, coal and oil for delivery terms through 2005.

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

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

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

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

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

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

The fair values in the table represent expected future cash flows based on the level of forward prices and volatility factors as of March 31, 2004 and could change significantly as a result of future changes in these factors. Additionally, because the depth and liquidity of the power markets varies substantially between regions and time periods, the prices used to determine fair value could be affected significantly by the volume of transactions executed.

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

Other

Quarter Ended March 31,	2004	2003
	(In millions)	
Revenues	$20.2	$15.1

Our merchant energy business holds up to a 50% ownership interest in 25 operating domestic energy projects that consist of electric generation, fuel processing, or fuel handling facilities. Of these 25 projects, 18 are "qualifying facilities" that receive certain exemptions and pricing under the Public Utility Regulatory Policy Act of 1978 based on the facilities' energy source or the use of a cogeneration process. In addition, we own 100% of a geothermal generating facility in Hawaii we expect to sell in mid-2004. We discuss our geothermal facility in more detail in the *Notes to Consolidated Financial Statements* on page 12.

We believe the current market conditions for our equity-method investments that own geothermal, coal, hydroelectric, and fuel processing projects provide sufficient positive cash flows to recover our investments. We continuously monitor issues that potentially could impact future profitability of these investments, including environmental and legislative initiatives. We discuss certain risks and uncertainties in more detail in our *Forward Looking Statements* section on page 54. However, should future events cause these investments to become

uneconomic, our investments in these projects could become impaired under the provisions of APB No. 18.

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

Given the need for electric power and the desire for renewable resource technologies, we believe California will continue to subsidize the use of renewable energy to make these projects economical to operate. However, should the California legislation fail to adequately support the renewable energy initiatives, our equity-method investments in these types of projects could become impaired under the provisions of APB No. 18, and any losses recognized could be material.

If our strategy were to change from an intent to hold to an intent to sell for any of our equity-method investments in qualifying facilities or power projects, we would need to adjust their book value to fair value, and that adjustment could be material. If we were to sell these investments in the current market, we may have losses that could be material.

Operations and Maintenance Expenses

Our merchant energy business operations and maintenance expenses increased $59.8 million in 2004 compared to 2003 mostly due to the following:

- an increase at our wholesale marketing and risk management operation and our retail commercial and industrial operation of $21.8 million due to the growth of these activities, and
- an increase of $21.6 million at our Nine Mile Point facility, including $11.5 million related to the refueling outage of Unit 2,
- an increase of $4.8 million due to the operations of the High Desert Power Project that commenced operations in the second quarter of 2003.

Depreciation and Amortization Expense

Merchant energy depreciation and amortization expense increased $4.8 million in 2004 compared to 2003 mostly because of the High Desert Power Project, which was placed into service during the second quarter of 2003.

Regulated Electric Business

As discussed in the *Regulated Electric Competition—Maryland* section on page 24, our regulated electric business was significantly impacted by the July 1, 2000 implementation of customer choice.

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

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

Results

Quarter Ended March 31,	2004	2003
	(In millions)	
Revenues	$ 484.4	$ 486.3
Electricity purchased for resale expenses	(240.4)	(243.6)
Operations and maintenance expenses	(65.1)	(54.2)
Depreciation and amortization	(47.8)	(44.2)
Taxes other than income taxes	(35.3)	(35.3)
Income from Operations	$ 95.8	$ 109.0
Net Income	$ 45.1	$ 50.2

Above amounts include intercompany transactions eliminated in our Consolidated Financial Statements. The Information by Operating Segment section within the Notes to Consolidated Financial Statements on page 14 provides a reconciliation of operating results by segment to our Consolidated Financial Statements.

Net income from the regulated electric business decreased during the quarter ended March 31, 2004 compared to the same period of 2003 mostly because of the following:

- milder weather in the first quarter of 2004 compared to the same period of 2003,
- increased operations and maintenance expenses primarily due to higher uncollectible expenses, increased spending on reliability, and higher benefit and other inflationary costs, and
- increased depreciation and amortization expense.

These unfavorable results were partially offset by lower interest expense and an increased number of customers.

Electric Revenues

The changes in electric revenues in 2004 compared to 2003 were caused by:

Quarter Ended March 31,	2004 vs. 2003
	(In millions)
Distribution sales volumes	$ 0.3
Standard offer service	0.1
Total change in electric revenues from electric system sales	0.4
Other	(2.3)
Total change in electric revenues	$(1.9)

Distribution Sales Volumes

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

The percentage changes in our distribution sales volumes, by type of customer, in 2004 compared to 2003 were:

Quarter Ended March 31,	2004 vs. 2003
Residential	(0.3)%
Commercial	(1.6)
Industrial	(0.7)

Standard Offer Service

BGE provides standard offer service for customers that do not select an alternative generation supplier as discussed in the *Regulated Electric Competition—Maryland* section on page 24.

Electricity Purchased for Resale Expenses

Electricity purchased for resale expenses include the cost of electricity purchased for resale to our standard offer service customers. These costs do not include the cost of electricity purchased by delivery service only customers.

Electric Operations and Maintenance Expenses

Regulated electric operations and maintenance expenses increased $10.9 million in 2004 compared to 2003 mostly due to higher uncollectible expenses, increased spending on reliability, and higher benefit and other inflationary costs.

Electric Depreciation and Amortization Expenses

Regulated electric depreciation and amortization expenses increased $3.6 million in 2004 compared to 2003 mostly because of increased depreciation expense associated with more property being placed in service and accelerated amortization expense associated with the planned replacement of information technology assets.

Regulated Gas Business

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

Results

Quarter Ended March 31,	2004	2003
	(In millions)	
Revenues	$ 319.5	$ 303.5
Gas purchased for resale expenses	(216.0)	(203.1)
Operations and maintenance expenses	(27.5)	(23.2)
Depreciation and amortization	(12.1)	(11.7)
Taxes other than income taxes	(9.9)	(9.9)
Income from operations	$ 54.0	$ 55.6
Net Income	$ 27.8	$ 28.6

Above amounts include intercompany transactions eliminated in our Consolidated Financial Statements. The Information by Operating Segment section within the Notes to Consolidated Financial Statements on page 14 provides a reconciliation of operating results by segment to our Consolidated Financial Statements.

Gas Revenues

The changes in gas revenues in 2004 compared to 2003 were caused by:

Quarter Ended March 31,	2004 vs. 2003
	(In millions)
Distribution sales volumes	$ 1.2
Base rates	(0.1)
Weather normalization	0.8
Gas cost adjustments	31.1
Total change in gas revenues from gas system sales	33.0
Off-system sales	(17.2)
Other	0.2
Total change in gas revenues	$ 16.0

Distribution Sales Volumes

The percentage changes in our distribution sales volumes, by type of customer, in 2004 compared to 2003 were:

Quarter Ended March 31,	2004 vs. 2003
Residential	0.2%
Commercial	10.1
Industrial	(16.7)

We distributed about the same amount of gas to residential customers in 2004 compared to 2003. We distributed more gas to commercial customers mostly due to increased usage per customer partially offset by milder weather. We distributed less gas to industrial customers mostly due to decreased usage.

Weather Normalization

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

Gas Cost Adjustments

We charge our gas customers for the natural gas they purchase from us using gas cost adjustment clauses set by the Maryland PSC as described in *Note 1* of our 2003 Annual Report on Form 10-K. 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.

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

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

Off-System Gas 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.

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

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

Gas costs increased in 2004 compared to 2003 because we purchased gas for system sales at a higher price.

Gas Operations and Maintenance Expenses
Regulated gas operations and maintenance expenses increased in 2004 compared to 2003 mostly due to higher uncollectible expenses and higher benefit and other inflationary costs.

Other Nonregulated Businesses

Results

Quarter Ended March 31,	2004	2003
	(In millions)	
Revenues	$103.8	$ 155.6
Operating expenses	(86.8)	(143.0)
Depreciation and amortization	(7.4)	(4.3)
Taxes other than income taxes	(0.5)	(1.0)
Net gain on sales of investments and other assets	1.5	13.7
Income from Operations	$ 10.6	$ 21.0
Net Income	$ 0.1	$ 8.7
Special Items Included in Operations (after-tax)		
Gains on sale of investments and other assets	$ 1.0	$ 8.3

Above amounts include intercompany transactions eliminated in our Consolidated Financial Statements. The Information by Operating Segment section within the Notes to Consolidated Financial Statements on page 14 provides a reconciliation of operating results by segment to our Consolidated Financial Statements.

During the quarter ended March 31, 2004, net income from our other nonregulated businesses decreased compared to the same period of 2003 mostly because we recognized $13.7 million pre-tax, or $8.3 million after-tax, gains on the sale of non-core assets in 2003 as follows:

- a $7.2 million pre-tax gain on the sale of an oil tanker to the U.S. Navy,
- a $5.3 million pre-tax gain on the favorable settlement of a contingent obligation we had previously reserved relating to the sale of our Guatemalan power plant operation in the fourth quarter of 2001, and
- a $1.2 million pre-tax gain on an installment sale of a parcel of real estate.

As previously discussed in our 2003 Annual Report on Form 10-K, we decided to sell certain non-core assets and accelerate the exit strategies on other assets that we will continue to hold and own over the next several years. While our intent is to dispose of these assets, market conditions and other events beyond our control may affect the actual sale of these assets. In addition, a future decline in the fair value of these assets could result in additional losses.

Consolidated Nonoperating Income and Expenses

Fixed Charges

During the quarter ended March 31, 2004, total fixed charges increased $4.3 million compared to the same period of 2003 mostly due to a higher level of debt outstanding, including the issuance of $550 million of debt in June 2003 that was used to refinance the High Desert Power Project lease.

During the quarter ended March 31, 2004, total fixed charges at BGE decreased $4.4 million compared to the same period of 2003 mostly because of a lower level of debt outstanding.

Income Taxes

During the quarter ended March 31, 2004, our income taxes increased $6.2 million compared to the same period of 2003 mostly because of an increase in taxable income partially offset by the recognition of synthetic fuel tax credits claimed in 2004 related to our investment in a South Carolina synthetic fuel facility, which reduced our effective tax rate. We discuss our synthetic fuel tax credits in more detail in the *Events of 2004—Synthetic Fuel Tax Credits* section on page 31.

During the quarter ended March 31, 2004, income taxes at BGE decreased $3.9 million compared to the same period of 2003 mostly because of lower taxable income.

Financial Condition

Cash Flows

The following table summarizes our cash flows for the first quarter of 2004 and 2003, excluding the impact of changes in intercompany balances.

	2004 Segment Cash Flows			Consolidated Cash Flows	
	Three Months Ended March 31, 2004			Three Months Ended March 31,	
	Merchant	Regulated	Other	2004	2003
			(In millions)		
Operating Activities					
Net (loss) income	$ (6.8)	$ 72.9	$ 0.1	$ 66.2	$(131.4)
Non-cash adjustments to net income	165.9	73.3	6.7	245.9	347.3
Changes in working capital	15.3	51.0	(9.1)	57.2	96.2
Pension and postemployment benefits*				(36.9)	(98.1)
Other	(19.1)	7.5	10.8	(0.8)	28.8
Net cash provided by operating activities	155.3	204.7	8.5	331.6	242.8
Investing activities					
Investments in property, plant and equipment	(111.2)	(52.1)	(8.0)	(171.3)	(145.2)
Contributions to nuclear decommissioning trust funds	(8.8)	—	—	(8.8)	(4.4)
Sale of investments and other assets	—	4.9	1.8	6.7	89.8
Other investments	(5.5)	—	(1.9)	(7.4)	(21.9)
Net cash used in investing activities	(125.5)	(47.2)	(8.1)	(180.8)	(81.7)
Cash flows from operating activities less cash flows from investing activities	$ 29.8	$157.5	$ 0.4	150.8	161.1
Financing Activities					
Net repayment of debt*				(4.5)	(133.0)
Proceeds from issuance of common stock*				15.2	10.1
Common stock dividends paid*				(43.5)	(39.6)
Other*				1.5	(1.4)
Net cash used in financing activities*				(31.3)	(163.9)
Net Increase (Decrease) in Cash and Cash Equivalents*				$ 119.5	$ (2.8)

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

Cash Flows from Operating Activities

Cash provided by operating activities was $331.6 million in 2004 compared to $242.8 million in 2003. Net income was $197.6 million higher in 2004 compared to 2003. This was partially offset by a decrease in non-cash adjustments to net income of $101.4 million in 2004 compared to 2003. The net decrease in non-cash adjustments to net income was primarily due to cumulative effects of changes in accounting principles of $198.4 million as a result of the adoption of SFAS No. 143 and EITF 02-3 in 2003, which had the effect of reducing net income but were non-cash transactions. This decrease in non-cash adjustments to net income was partially offset by the following increases:

- a loss from discontinued operations of $46.3 million in 2004;
- an increase in deferred fuel costs of $28.9 million in 2004 compared to 2003; and
- an increase in depreciation and amortization of $17.2 million in 2004 compared to 2003.

Changes in working capital had a positive impact of $57.2 million on cash flow from operations in 2004 compared to $96.2 million in 2003. The net decrease of $39.0 million was primarily due to a $32 million federal tax refund in 2003 and a federal tax payment in 2004. This decrease in working capital was partially offset by a

source of cash resulting from a larger decrease in BGE natural gas fuel stocks in 2004 compared to 2003. Pension and postemployment benefits were a use of cash of $39.6 million in 2004 compared to $98.1 million in 2003. This primarily reflects a $60 million lower contribution to the pension plan in 2004 compared to 2003.

Cash Flows from Investing Activities
Cash used in investing activities was $180.8 million in 2004 compared to $81.7 million in 2003. The increase in cash used in 2004 compared to 2003 was primarily due to a decrease in cash proceeds from the sales of investments and other assets and an increase in investments in property, plant and equipment.

Cash Flows from Financing Activities
Cash used in financing activities was $31.3 million in 2004 compared to $163.9 million in 2003. The decrease in 2004 compared to 2003 was mostly due to a lower repayment of debt in 2004 compared to 2003.

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

The factors that credit rating agencies consider in establishing Constellation Energy's and BGE's credit ratings include, but are not limited to, cash flows, liquidity, and the amount of debt as a component of total capitalization. In March 2004, Standard & Poors rating group reduced Constellation Energy's and BGE's corporate credit rating from A- to BBB+ and reduced certain other ratings as noted in the table below. All Constellation Energy and BGE credit ratings have stable outlooks. At the date of this report, our credit ratings were as follows:

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

** In March 2004, Standard & Poors Rating Group reduced the rating one level to this current rating.*

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

Constellation Energy
In addition to our cash balance, we have a commercial paper program under which we can issue short-term notes to fund our subsidiaries. At March 31, 2004, we had approximately $1.5 billion of credit under three facilities. These facilities include:

- a $447.5 million 364-day revolving credit facility that expires in June 2004,
- a $447.5 million three-year revolving credit facility that expires in June 2006, and
- a $640.0 million revolving credit facility that expires in June 2005.

We use these facilities to allow the issuance of commercial paper. In addition, we use the multi-year facilities to allow for the issuance of letters of credit.

These revolving credit facilities allow the issuance of letters of credit up to approximately $1.1 billion. At March 31, 2004, letters of credit that totaled $730.5 million were issued under all of our facilities, which results in approximately $805 million of unused credit facilities.

BGE
BGE maintains $200.0 million in annual committed credit facilities, expiring May through November of 2004, in order to allow commercial paper to be issued. As of March 31, 2004, BGE had no outstanding commercial paper, which results in $200.0 million in unused credit facilities.

Other Nonregulated Businesses
BGE Home Products & Services' program to sell up to $50 million of receivables was not extended beyond its March 2004 expiration date. We expect to fully liquidate this receivables program by the end of 2004.

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

Capital Resources

Our estimated annual amounts for the years 2004 and 2005 are shown in the table below.

We will continue to have cash requirements for:

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

Capital requirements for 2004 and 2005 include estimates of spending for existing and anticipated projects. We continuously review and modify those estimates. Actual requirements may vary from the estimates included in the table below because of a number of factors including:

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

Our estimates are also subject to additional factors. Please see the *Forward Looking Statements* section on page 54.

Calendar Year Estimates	2004	2005
	(In millions)	
Nonregulated Capital Requirements:		
Merchant energy		
Generation plants	$170	$155
Nuclear fuel	115	65
Portfolio acquisitions	60	60
Technology/other	105	85
Total merchant energy capital requirements (A)	450	365
Other nonregulated capital requirements	40	50
Total nonregulated capital requirements	490	415
Utility Capital Requirements:		
Regulated electric	220	250
Regulated gas	60	55
Total utility capital requirements	280	305
Total capital requirements	$770	$720

(A) Excludes approximately $25 million of 2004 and approximately $50 million of 2005 capital requirements, including nuclear fuel for Ginna. We discuss our planned acquisition of Ginna in the *Events of 2004* section on page 32.

Capital Requirements

Merchant Energy Business

Our merchant energy business' capital requirements consist of its continuing requirements, including construction expenditures for improvements to generating plants, nuclear fuel costs, costs of complying with the Environmental Protection Agency (EPA), Maryland, and Pennsylvania nitrogen oxides (NOx) emissions regulations, and enhancements to our information technology infrastructure. We discuss the NOx regulations and timing of expenditures in *Note 12* of our 2003 Annual Report on Form 10-K.

Regulated Electric and Gas

Regulated electric and gas construction expenditures primarily include new business construction needs and improvements to existing facilities, including projects to improve reliability.

Funding for Capital Requirements

Merchant Energy Business

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

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

We expect to fund acquisitions, including Ginna, with an overall goal of maintaining a strong investment grade credit profile. Funding of this acquisition is expected to occur in mid-2004.

Regulated Electric and Gas

Funding for utility capital expenditures is expected from internally generated funds. During 2004, we expect our regulated businesses to generate sufficient cash flows from operations to meet BGE's operating requirements. If necessary, additional funding may be obtained from commercial paper issuances, available capacity under credit facilities, the issuance of long-term debt, trust securities, or preference stock, and/or from time to time equity contributions from Constellation Energy. BGE also participates in a cash pool administered by Constellation Energy as discussed in the *Notes to Consolidated Financial Statements* section on page 21.

Other Nonregulated Businesses

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

Our ability to sell or liquidate securities and non-core assets will depend on market conditions, and we cannot give assurances that these sales or liquidations could be made.

Contractual Payment Obligations and Committed Amounts

Our total contractual payment obligations as of March 31, 2004 are shown in the following table:

	Payments				
	2004	2005-2006	2007-2008	Thereafter	Total
	(In millions)				
Contractual Payment Obligations					
Long-term debt:[1]					
Nonregulated					
Principal	$ 10.2	$ 343.9	$ 636.0	$2,744.8	$ 3,734.9
Interest	175.8	433.8	364.1	1,741.7	2,715.4
Total	186.0	777.7	1,000.1	4,486.5	6,450.3
BGE					
Principal	151.4	482.7	418.5	600.8	1,653.4
Interest	66.4	169.4	96.7	824.0	1,156.5
Total	217.8	652.1	515.2	1,424.8	2,809.9
BGE preference stock	—	—	—	190.0	190.0
Operating leases	17.3	40.9	27.1	121.5	206.8
Purchase obligations:[2]					
Purchased capacity and energy[3]	990.2	1,118.3	274.9	207.2	2,590.6
Fuel and transportation[4]	499.0	509.5	116.2	52.8	1,177.5
Other	61.5	67.0	34.0	247.8	410.3
Other noncurrent liabilities:					
Postretirement and postemployment benefits[5]	38.0	87.0	99.5	139.7	364.2
Other	5.7	5.9	—	—	11.6
Total contractual payment obligations	$2,015.5	$3,258.4	$2,067.0	$6,870.3	$14,211.2

1 Amounts in long-term debt reflect the original maturity date. Investors may require us to repay $327.0 million early through put options and remarketing features.

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

3 Our contractual obligations for purchased capacity and energy are shown on a gross basis for certain transactions, including both the fixed payment portions of tolling contracts and estimated variable payments under unit-contingent power purchase agreements. We have recorded $30.3 million of liabilities related to purchased capacity and energy obligations at March 31, 2004 in our Consolidated Balance Sheets.

4 We have recorded liabilities of $64.5 million related to fuel and transportation obligations at March 31, 2004 in our Consolidated Balance Sheets.

5 Amounts related to postretirement and postemployment benefits are for unfunded plans and reflect present value amounts consistent with the determination of the related liabilities recorded on the Consolidated Balance Sheets.

The table on the next page presents our contingent obligations. Our contingent obligations increased $1.2 billion during the first quarter of 2004, primarily due to the issuance of additional guarantees and letters of credit by the parent company for subsidiary obligations to third parties in support of the growth of our merchant energy business. These amounts do not represent incremental consolidated Constellation Energy obligations; rather they primarily represent parental guarantees of certain subsidiary obligations to third parties. Our calculation of the fair value of subsidiary obligations covered by the $4,592.0 million of parent company guarantees was $1,125.8 million at March 31, 2004. Accordingly, if the parent company was required to fund subsidiary obligations, the total amount at current market prices is $1,125.8 million.

	Expiration				
	2004	2005-2006	2007-2008	Thereafter	Total
			(In millions)		
Contingent Obligations					
Letters of credit	$ 697.7	$ 32.8	$ —	$ —	$ 730.5
Guarantees—competitive supply[1]	3,306.9	495.0	292.0	498.1	4,592.0
Other guarantees, net[2]	9.9	11.6	—	838.1	859.6
Total contingent obligations	$4,014.5	$539.4	$292.0	$1,336.2	$6,182.1

1 While the face amount of these guarantees is $4,592.0 million, we do not expect to fund the full amount. Our calculation of the fair value of obligations covered by these guarantees was $1,125.8 million at March 31, 2004.

2 Other guarantees in the above table are shown net of liabilities of $25.6 million recorded at March 31, 2004 in our Consolidated Balance Sheets.

Liquidity Provisions

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

Under certain counterparty contracts related to our wholesale marketing and risk management operation, we are obligated to post collateral if Constellation Energy's senior, unsecured credit ratings decline below established contractual levels. As a result of the ratings action taken by Standard & Poors rating agency in March 2004, we posted approximately $40 million in additional collateral to support our wholesale marketing and risk management operational requirements. We discuss the Standard & Poors ratings action in more detail in the *Financial Condition* section on page 45.

Based on contractual provisions, we estimate that we would have additional collateral obligations based on downgrades to the following credit ratings for our Senior Unsecured Debt:

Credit Ratings Downgraded	Level Below Current Rating	Incremental Obligations	Cumulative Obligations
		(In millions)	
BBB-/Baa3	1	$127	$127
Below investment grade	2	669	796

At March 31, 2004, we had approximately $1.0 billion of unused credit facilities and $840.8 million of cash available to meet these potential requirements. However, based on market conditions and contractual obligations at the time of such a downgrade, we could be required to post collateral in an amount that could exceed the amounts specified above, and which could be material.

We consistently review our liquidity needs to ensure that we have adequate facilities available to meet these requirements. This includes having liquidity available to meet margin requirements for our wholesale marketing and risk management operation.

In many cases, customers of our wholesale marketing and risk management operation rely on the creditworthiness of Constellation Energy. A decline below investment grade by Constellation Energy would negatively impact the business prospects of that operation. The credit facilities of Constellation Energy and BGE have limited material adverse change clauses that only consider a material change in financial condition and are not directly affected by decreases in credit ratings. If these clauses are violated, the lending institutions can decline making new advances or issuing new letters of credit, but cannot accelerate existing amounts outstanding. The long-term debt indentures of Constellation Energy and BGE do not contain material adverse change clauses or financial covenants.

Certain credit facilities of Constellation Energy contain a provision requiring Constellation Energy to maintain a ratio of debt to capitalization equal to or less than 65%. At March 31, 2004, the debt to capitalization ratios as defined in the credit agreements were no greater than 55%. Certain credit facilities of BGE contain provisions requiring BGE to maintain a ratio of debt to capitalization equal to or less than 65%. At March 31, 2004, the debt to capitalization ratio for BGE as defined in these credit agreements was 49%. At March 31, 2004, no amount is outstanding under these facilities.

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

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

Market Risk

Commodity Risk

During the first quarter of 2004, the energy markets continued to be highly volatile with significant increases in fuel prices, primarily natural gas and coal, and power prices as well as the continuation of reduced liquidity in the marketplace.

We measure the sensitivity of our wholesale marketing and risk management mark-to-market energy contracts to potential changes in market prices using value at risk. Value at risk represents the potential pre-tax loss in the fair value of our wholesale marketing and risk management mark-to-market energy assets and liabilities over one and ten-day holding periods. We discuss value at risk in more detail in the *Market Risk* section of our 2003 Annual Report on Form 10-K. The table below is the value at risk associated with our wholesale marketing and risk management operation's mark-to-market energy assets and liabilities, including both trading and non-trading activities.

	Quarter Ended March 31, 2004
	(In millions)
99% Confidence Level, One-Day Holding Period	
Average	$ 4.2
High	6.3
95% Confidence Level, One-Day Holding Period	
Average	3.2
High	4.8
95% Confidence Level, Ten-Day Holding Period	
Average	10.2
High	15.1

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

	Quarter Ended March 31, 2004
	(In millions)
Average	$2.3
High	5.3

Due to the inherent limitations of statistical measures such as value at risk and the seasonality of changes in market prices, the value at risk calculation may not reflect the full extent of our commodity price risk exposure. Additionally, actual changes in the value of options may differ from the value at risk calculated using a linear approximation inherent in our calculation method.

As a result, actual changes in the fair value of mark-to-market energy assets and liabilities could differ from the calculated value at risk, and such changes could have a material impact on our financial results.

Wholesale Credit Risk

We continue to actively manage the credit portfolio of our wholesale marketing and risk management operation to attempt to reduce the impact of the general decline in the overall credit quality of the energy industry and the impact of a potential counterparty default. As of March 31, 2004 and December 31, 2003, the credit portfolio of our wholesale marketing and risk management operation had the following public credit ratings:

	March 31, 2004	December 31, 2003
Rating		
Investment Grade[1]	69%	75%
Non-Investment Grade	10	4
Not Rated	21	21

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

In addition to the credit ratings provided by the major credit rating agencies, we utilize internal credit ratings to evaluate the creditworthiness of our wholesale customers, including those companies that do not have public credit ratings. The "Not Rated" category in the table above includes counterparties that do not have public credit ratings and include governmental entities, municipalities, cooperatives, power pools, and other load-serving entities, and marketers for which we determine creditworthiness based on internal credit ratings.

The following table provides the breakdown of the credit quality of our wholesale credit portfolio based on our internal credit ratings.

	March 31, 2004	December 31, 2003
Investment Grade Equivalent	81%	91%
Non-Investment Grade	19	9

Compared to December 31, 2003, we have experienced deterioration in the credit quality of our wholesale marketing and risk management portfolio measured using both public credit ratings and our internal credit ratings. The decline in investment grade equivalent counterparties is primarily due to increased exposure to lower credit quality fuel and power supply counterparties. A portion of our wholesale credit risk is related to transactions that are recorded in our Consolidated Balance Sheets. These transactions primarily consist of open positions from our wholesale marketing and risk management operation that are accounted for using mark-to-market accounting, as well as amounts owed by wholesale counterparties for transactions that settled but have not yet been paid. The following table highlights the credit quality and exposures related to these activities at March 31, 2004:

Rating	Total Exposure Before Credit Collateral	Credit Collateral	Net Exposure	Number of Counterparties Greater than 10% of Net Exposure	Net Exposure of Counterparties Greater than 10% of Net Exposure
	(Dollars in millions)				
Investment grade	$ 667	$ 47	$620	1	$90
Split rating	11	—	11	—	—
Non-investment grade	165	141	24	—	—
Internally rated—investment grade	153	89	64	—	—
Internally rated—non-investment grade	37	10	27	—	—
Total	$1,033	$287	$746	1	$90

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

Additionally, if a counterparty were to default and we were to liquidate all contracts with that entity, our credit loss would include the loss in value of mark-to-market contracts, the amount owed for settled transactions, and additional payments, if any, we would have to make to settle unrealized losses on accrual contracts.

We continue to examine plans to achieve our strategies and to further strengthen our balance sheet and enhance our liquidity. We discuss our liquidity in the *Financial Condition* section on page 48.

Interest Rate Risk, Retail Credit Risk, and Equity Price Risk

We discuss our exposure to interest rate risk, retail credit risk, and equity price risk in the *Market Risk* section of our 2003 Annual Report on Form 10-K.

Other Matters

Environmental Matters

We are subject to federal, state, and local laws and regulations that work to improve or maintain the quality of the environment. If certain substances were disposed of, or released at any of our properties, whether currently operating or not, these laws and regulations require us to remove or remedy the effect on the environment. This includes Environmental Protection Agency Superfund sites.

You will find details of our environmental matters in the *Environmental Matters* section of the *Notes to Consolidated Financial Statements* beginning on page 17 and in our 2003 Annual Report on Form 10-K in *Item 1. Business—Environmental Matters.* These details include financial information. Some of the information is about costs that may be material.

Accounting Standards Adopted

We discuss recently adopted accounting standards in the *Accounting Standards Adopted* section of the *Notes to Consolidated Financial Statements* beginning on page 20.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

We discuss the following information related to our market risk:

- SFAS No. 133 hedging activities section in the *Notes to Consolidated Financial Statements* beginning on page 19,
- activities of our wholesale marketing and risk management operation in the *Merchant Energy Business* section of *Management's Discussion and Analysis* beginning on page 34,
- evaluation of commodity and wholesale credit risk in the *Market Risk* section of *Management's Discussion and Analysis* beginning on page 49, and
- changes to our business environment in the *Business Environment* section of *Management's Discussion and Analysis* beginning on page 24.

Item 4. Controls and Procedures

A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within Constellation Energy or BGE have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple error or mistake. Additionally, controls can be circumvented by the individual acts of some persons or by collusion of two or more people.

The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no absolute assurance that any design will succeed in achieving its stated goals under all potential future conditions; over time, controls may become inadequate because of changes in conditions, or the degree of compliance with the policies or procedures may deteriorate. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected.

The principal executive officers and principal financial officer of both Constellation Energy and BGE have evaluated the effectiveness of the disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")) as of the end of the fiscal quarter covered by this quarterly report (the "Evaluation Date"). Based on such evaluation, such officers have concluded that, as of the Evaluation Date, Constellation Energy's and BGE's disclosure controls and procedures are effective, in that they provide reasonable assurance that such officers are alerted on a timely basis to material information relating to Constellation Energy and BGE that is required to be included in Constellation Energy's and BGE's periodic filings under the Exchange Act.

PART II. OTHER INFORMATION
Item 1. Legal Proceedings

California

Baldwin Associates, Inc. v. Gray Davis, Governor of California and 22 other defendants (including Constellation Power Development, Inc., a subsidiary of Constellation Power, Inc.)—This class action lawsuit was filed on October 5, 2001 in the Superior Court, County of San Francisco. The action seeks damages of $43 billion, recession and reformation of approximately 38 long-term power purchase contracts, and an injunction against improper spending by the state of California.

Constellation Power Development, Inc. is named as a defendant but has never been served with process in this case and does not have a power purchase agreement with the State of California. However, our High Desert Power Project does have a power purchase agreement with the California Department of Water Resources. The court issued an order to the plaintiff asking that he show cause why he had not yet served any of the defendants with process. A hearing is scheduled on August 23, 2004 on the court's show cause order.

James M. Millar v. Allegheny Energy Supply, Constellation Power Source, Inc., High Desert Power Project, LLC, et al—On December 19, 2003, plaintiffs filed an amended complaint in Superior Court of California, County of San Francisco, naming for the first time, Constellation Power Source, Inc. (CPS) and High Desert Power Project, LLC (High Desert), two of our subsidiaries, as additional defendants. The complaint is a putative class action on behalf of California electricity consumers and alleges that the defendant power suppliers, including CPS and High Desert, violated California's Unfair Competition Law in connection with certain long-term power contracts that the defendants negotiated with the California Department of Water Resources in 2001 and 2002. Notwithstanding the amended long-term power contracts and the releases and settlement agreements negotiated at the time of such amendments, the plaintiff seeks to have the Court certify the case as a class action and to order the repayment of any monies that were acquired by the defendants under the long-term contracts or the amended long-term contracts by means of unfair competition in violation of California law. The amended complaint was removed to federal court by one of the defendants and a motion to remand the case back to the state court is pending before the federal court. We believe that we have meritorious defenses to this action and intend to defend against it vigorously. However, we can not predict the timing, or outcome, of this case, or its possible effect on our results.

NewEnergy

Constellation NewEnergy, Inc. v. PowerWeb Technology, Inc.—Prior to our acquisition, NewEnergy filed a complaint on May 9, 2002 in the U.S. District Court of Eastern Pennsylvania seeking approximately $100,000 in direct damages relating to a contract previously entered into with PowerWeb. PowerWeb Technology has counter-claimed seeking $100 million in damages against NewEnergy alleging a breach of a non-disclosure agreement by misappropriation of trade secrets and tortious interference claims. Discovery is ongoing in the matter. We cannot predict the timing, or outcome, of the action or its possible effect on our financial results. However, based on the information available to Constellation Energy at this time, we believe NewEnergy has meritorious defenses to the PowerWeb Technology counterclaim.

Mercury Poisoning

Beginning in September 2002, BGE, Constellation Energy, and several other defendants have been involved in numerous actions filed in the Circuit Court for Baltimore City, Maryland alleging mercury poisoning from several sources, including coal plants formerly owned by BGE. The plants are now owned by a subsidiary of Constellation Energy. In addition to BGE and Constellation Energy, approximately 11 other defendants, consisting of pharmaceutical companies, manufacturers of vaccines and manufacturers of Thimerosal have been sued. Approximately 50 cases have been filed to date, with each case seeking $90 million in damages from the group of defendants.

In a ruling applicable to all but several of the cases, the Circuit Court for Baltimore City dismissed with prejudice all claims against BGE and Constellation Energy and entered into a stay of the proceedings as they relate to other defendants. The several cases that were not dismissed were filed subsequent to the ruling by the Circuit Court. Plaintiffs may attempt to pursue appeals of the rulings in favor of BGE and Constellation Energy once the cases are finally concluded as to all defendants. We believe that we have meritorious defenses and intend to defend the actions vigorously. However, we cannot predict the timing, or outcome, of these cases, or their possible effect on our, or BGE's, financial results.

Employment Discrimination

Miller, et. al v. Baltimore Gas and Electric Company, et al.—This action was filed on September 20, 2000 in the U.S. District Court for the District of Maryland. Besides BGE, Constellation Energy Group, Constellation Nuclear, and Calvert Cliffs Nuclear Power Plant are also named defendants. The action seeks class certification for approximately 150 past and present employees and alleges racial discrimination at Calvert Cliffs Nuclear Power Plant.

The amount of damages is unspecified, however the plaintiffs seek back and front pay, along with compensatory and punitive damages. The Court scheduled a briefing process for the motion to certify the case as a class action suit. The briefing process concluded and oral argument on the class certification motion was held on April 16, 2004, and the parties are awaiting the court's decision. We do not believe class certification is appropriate and we further believe that we have meritorious defenses to the underlying claims and intend to defend the action vigorously. However, we cannot predict the timing, or outcome, of the action or its possible effect on our, or BGE's, financial results.

Asbestos

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

The first type is direct claims by individuals exposed to asbestos. BGE is involved in these claims with approximately 70 other defendants. Approximately 560 individuals that were never employees of BGE each claim $6 million in damages ($2 million compensatory and $4 million punitive). These claims are currently pending in state courts in Maryland and Pennsylvania. BGE does not know the specific facts necessary to estimate its potential liability for these claims. The specific facts BGE does not know include:

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

To date, 279 asbestos cases were dismissed or resolved for amounts that were not significant. Approximately 51 cases are currently scheduled for trial by the end of 2004.

The second type is claims by one manufacturer—Pittsburgh Corning Corp. (PCC)—against BGE and approximately eight others, as third-party defendants. On April 17, 2000, PCC declared bankruptcy.

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

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

Until the relevant facts for both types of claims are determined, we are unable to estimate what our, or BGE's, liability might be. Although insurance and hold harmless agreements from contractors who employed the plaintiffs may cover a portion of any awards in the actions, the potential effect on our, or BGE's, financial results could be material.

Item 5. Other Information

Forward Looking Statements

We make statements in this report that are considered forward looking statements within the meaning of the Securities Exchange Act of 1934. Sometimes these statements will contain words such as "believes," "anticipates," "expects," "intends," "plans," and other similar words. We also disclose non-historical information that represents management's expectations, which are based on numerous assumptions. These statements and projections are not guarantees of our future performance and are subject to risks, uncertainties, and other important factors that could cause our actual performance or achievements to be materially different from those we project. These risks, uncertainties, and factors include, but are not limited to:

- the timing and extent of changes in commodity prices and volatilities for energy and energy related products including coal, natural gas, oil, electricity, and emission allowances,
- the timing and extent of deregulation of, and competition in, the energy markets in North America, and the rules and regulations adopted on a transitional basis in those markets,
- the conditions of the capital markets, interest rates, availability of credit, liquidity, and general economic conditions, as well as Constellation Energy Group's (Constellation Energy) and Baltimore Gas and Electric Company's (BGE) ability to maintain their current credit ratings,
- the effectiveness of Constellation Energy's and BGE's risk management policies and procedures and the ability and willingness of our counterparties to satisfy their financial and performance commitments,
- the liquidity and competitiveness of wholesale markets for energy commodities,
- operational factors affecting commercial operations of our generating facilities (including nuclear facilities) and BGE's transmission and distribution facilities, including catastrophic weather related damages, unscheduled outages or repairs, unanticipated changes in fuel costs or availability, unavailability of gas transportation or electric transmission services, workforce issues, terrorism, liabilities associated with catastrophic events, and other events beyond our control,
- the inability of BGE to recover all its costs associated with providing electric retail customers service during the electric rate freeze period,
- the effect of weather and general economic and business conditions on energy supply, demand, and prices,
- regulatory or legislative developments that affect deregulation, transmission or distribution rates and revenues, demand for energy, or increases in costs, including costs related to nuclear power plants, safety, or environmental compliance,
- the actual outcome of uncertainties associated with assumptions and estimates using judgment when applying critical accounting policies and preparing financial statements, including factors that are estimated in determining the fair value of energy contracts, such as the ability to obtain market prices and in the absence of verifiable market prices the appropriateness of models and model inputs (including, but not limited to, estimated contractual load obligations, unit availability, forward commodity prices, interest rates, correlation and volatility factors),
- changes in accounting principles or practices,
- the ability to attract and retain customers in our competitive supply activities and to adequately forecast their energy usage,
- losses on the sale or write down of assets due to impairment events or changes in management intent with regard to either holding or selling certain assets, and
- cost and other effects of legal and administrative proceedings that may not be covered by insurance, including environmental liabilities.

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

Changes may occur after that date, and neither Constellation Energy nor BGE assume responsibility to update these forward looking statements.

Item 6. Exhibits and Reports on Form 8-K

(a)	Exhibit No. 3(a)	Bylaws of Constellation Energy Group, Inc. as amended February 27, 2004.
	Exhibit No. 10(a)	Executive Annual Incentive Plan of Constellation Energy Group, Inc., as amended and restated.
	Exhibit No. 10(b)	Constellation Energy Group, Inc. 1995 Long-Term Incentive Plan, as amended and restated.
	Exhibit No. 10(c)	Constellation Energy Group, Inc. Deferred Compensation Plan for Non-Employee Directors, as amended and restated.
	Exhibit No. 10(d)	Constellation Energy Group, Inc. Supplemental Pension Plan, as amended and restated.
	Exhibit No. 10(e)	Constellation Energy Group, Inc. Senior Executive Supplemental Plan, as amended and restated.
	Exhibit No. 10(f)	Change in Control Severance Agreement between Constellation Energy Group, Inc. and Thomas V. Brooks.
	Exhibit No. 10(g)	Constellation Energy Group, Inc. Executive Long-Term Incentive Plan, as amended and restated.
	Exhibit No. 10(h)	Constellation Energy Group, Inc. 2002 Executive Annual Incentive Plan, as amended and restated.
	Exhibit No. 10(i)	Constellation Energy Group, Inc. 2002 Senior Management Long-Term Incentive Plan, as amended and restated.
	Exhibit No. 10(j)	Constellation Energy Group, Inc. Management Long-Term Incentive Plan, as amended and restated.
	Exhibit No. 12(a)	Constellation Energy Group, Inc. Computation of Ratio of Earnings to Fixed Charges.
	Exhibit No. 12(b)	Baltimore Gas and Electric Company Computation of Ratio of Earnings to Fixed Charges and Computation of Ratio of Earnings to Combined Fixed Charges and Preferred and Preference Dividend Requirements.
	Exhibit No. 31(a)	Certification of Chairman of the Board, Chief Executive Officer and President of Constellation Energy Group, Inc. pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
	Exhibit No. 31(b)	Certification of Executive Vice President and Chief Financial Officer of Constellation Energy Group, Inc. pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
	Exhibit No. 31(c)	Certification of President and Chief Executive Officer of Baltimore Gas and Electric Company pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
	Exhibit No. 31(d)	Certification of Senior Vice President and Chief Financial Officer of Baltimore Gas and Electric Company pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
	Exhibit No. 32(a)	Certification of Chairman of the Board, Chief Executive Officer and President of Constellation Energy Group, Inc. pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
	Exhibit No. 32(b)	Certification of Executive Vice President and Chief Financial Officer of Constellation Energy Group, Inc. pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

Exhibit No. 32(c)	Certification of President and Chief Executive Officer of Baltimore Gas and Electric Company pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
Exhibit No. 32(d)	Certification of Senior Vice President and Chief Financial Officer of Baltimore Gas and Electric Company pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

(b) Reports on Form 8-K for the quarter ended March 31, 2004:

Date	Item Reported
January 30, 2004	Item 7. Financial Statements and Exhibits Item 12. Results of Operations and Financial Condition

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, each registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

CONSTELLATION ENERGY GROUP, INC.

(Registrant)

BALTIMORE GAS AND ELECTRIC COMPANY

(Registrant)

Date: May 7, 2004

/s/ E. FOLLIN SMITH

E. Follin Smith,

Executive Vice President of Constellation Energy Group, Inc. and Senior Vice President of Baltimore Gas and Electric Company, and as Principal Financial Officer of each Registrant

Exhibit 12(a)

CONSTELLATION ENERGY GROUP, INC. AND SUBSIDIARIES

COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES

	3 Months Ended	Twelve Months Ended				
	March 2004	December 2003	December 2002	December 2001	December 2000	December 1999
			(In millions)			
Income from Continuing Operations (Before Extraordinary Loss, Cumulative Effects of Changes in Accounting Principles and Loss from Discontinued Operations)	$112.5	$ 475.7	$ 525.6	$ 82.4	$345.3	$326.4
Taxes on Income, Including Tax Effect for BGE Preference Stock Dividends	40.3	261.0	301.0	29.7	221.4	182.5
Adjusted Income	$152.8	$ 736.7	$ 826.6	$112.1	$566.7	$508.9
Fixed Charges:						
Interest and Amortization of Debt Discount and Expense and Premium on all Indebtedness	$ 82.6	$ 329.3	$ 270.2	$226.1	$261.5	$245.7
Earnings Required for BGE Preference Stock Dividends	5.5	21.7	21.8	21.4	21.9	21.0
Capitalized Interest	2.4	12.2	42.5	55.8	21.1	2.7
Interest Factor in Rentals	1.0	3.5	2.1	2.0	2.2	1.8
Total Fixed Charges	$ 91.5	$ 366.7	$ 336.6	$305.3	$306.7	$271.2
Amortization of Capitalized Interest	$ 1.0	$ 3.1	$ 1.3	$ 0.1	$ —	$ —
Earnings (1)	$242.9	$1,094.3	$1,122.0	$361.7	$852.3	$777.4
Ratio of Earnings to Fixed Charges	2.66	2.98	3.33	1.18	2.78	2.87

(1) Earnings are deemed to consist of income from continuing operations (before extraordinary loss, cumulative effects of changes in accounting principles, and loss from discontinued operations) that includes earnings of Constellation Energy's consolidated subsidiaries, equity in the net income of unconsolidated subsidiaries, income taxes (including deferred income taxes, investment tax credit adjustments, and the tax effect of BGE's preference stock dividends), and fixed charges (including the amortization of capitalized interest but excluding the capitalization of interest).

Exhibit 12(b)

BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARIES

COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES AND COMPUTATION OF RATIO OF EARNINGS TO COMBINED FIXED CHARGES AND PREFERRED AND PREFERENCE DIVIDEND REQUIREMENTS

	3 Months Ended	12 Months Ended				
	March 2004	December 2003	December 2002	December 2001	December 2000	December 1999
			(In millions)			
Income from Continuing Operations (Before Extraordinary Loss)	$ 76.0	$163.2	$143.1	$ 97.3	$143.5	$328.4
Taxes on Income	49.7	105.2	93.3	60.3	94.2	182.0
Adjusted Income	$125.7	$268.4	$236.4	$157.6	$237.7	$510.4
Fixed Charges:						
Interest and Amortization of Debt Discount and Expense and Premium on all Indebtedness	$ 25.4	$112.8	$142.1	$158.8	$186.8	$206.4
Capitalized Interest	—	—	—	—	—	0.4
Interest Factor in Rentals	0.2	0.7	0.5	0.7	0.9	1.0
Total Fixed Charges	$ 25.6	$113.5	$142.6	$159.5	$187.7	$207.8
Preferred and Preference Dividend Requirements: (1)						
Preferred and Preference Dividends	$ 3.3	$ 13.2	$ 13.2	$ 13.2	$ 13.2	$ 13.5
Income Tax Required	2.2	8.6	8.6	8.2	8.7	7.5
Total Preferred and Preference Dividend Requirements	$ 5.5	$ 21.8	$ 21.8	$ 21.4	$ 21.9	$ 21.0
Total Fixed Charges and Preferred and Preference Dividend Requirements	$ 31.1	$135.3	$164.4	$180.9	$209.6	$228.8
Earnings (2)	$151.3	$381.9	$379.0	$317.1	$425.4	$717.8
Ratio of Earnings to Fixed Charges	5.91	3.36	2.66	1.99	2.27	3.45
Ratio of Earnings to Combined Fixed Charges and Preferred and Preference Dividend Requirements	4.86	2.82	2.31	1.75	2.03	3.14

(1) Preferred and preference dividend requirements consist of an amount equal to the pre-tax earnings that would be required to meet dividend requirements on preferred stock and preference stock.

(2) Earnings are deemed to consist of income from continuing operations (before extraordinary loss) that includes earnings of BGE's consolidated subsidiaries, income taxes (including deferred income taxes and investment tax credit adjustments), and fixed charges other than capitalized interest.

Exhibit 31(a)

CONSTELLATION ENERGY GROUP, INC.

CERTIFICATION

I, Mayo A. Shattuck III, certify that:

1. I have reviewed this report on Form 10-Q of Constellation Energy Group, Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (c) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal controls over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 7, 2004

_____

Chairman of the Board, Chief Executive Officer
and President

Exhibit 31(b)

CONSTELLATION ENERGY GROUP, INC.

CERTIFICATION

I, E. Follin Smith, certify that:

1. I have reviewed this report on Form 10-Q of Constellation Energy Group, Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (c) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal controls over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 7, 2004

_____

Executive Vice President and Chief Financial Officer

Exhibit 31(c)

BALTIMORE GAS AND ELECTRIC COMPANY

CERTIFICATION

I, Frank O. Heintz, certify that:

1. I have reviewed this report on Form 10-Q of Baltimore Gas and Electric Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (c) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal controls over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 7, 2004

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President and Chief Executive Officer

Exhibit 31(d)

BALTIMORE GAS AND ELECTRIC COMPANY

CERTIFICATION

I, E. Follin Smith, certify that:

1. I have reviewed this report on Form 10-Q of Baltimore Gas and Electric Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (c) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal controls over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 7, 2004

_____

Senior Vice President and Chief Financial Officer

Exhibit 32(a)

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

I, Mayo A. Shattuck III, Chairman of the Board, Chief Executive Officer and President of Constellation Energy Group, Inc., certify pursuant to 18 U.S.C. Section 1350 adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that to my knowledge:

(i) The accompanying Quarterly Report on Form 10-Q for the quarter ended March 31, 2004 fully complies with the requirements of Section 13(a) or Section 15(d) of the Securities Exchange Act of 1934, as amended; and

(ii) The information contained in such report fairly presents, in all material respects, the financial condition and results of operations of Constellation Energy Group, Inc.

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

Date: May 7, 2004

Exhibit 32(b)

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

I, E. Follin Smith, Executive Vice President and Chief Financial Officer of Constellation Energy Group, Inc., certify pursuant to 18 U.S.C. Section 1350 adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that to my knowledge:

(i) The accompanying Quarterly Report on Form 10-Q for the quarter ended March 31, 2004 fully complies with the requirements of Section 13(a) or Section 15(d) of the Securities Exchange Act of 1934, as amended; and

(ii) The information contained in such report fairly presents, in all material respects, the financial condition and results of operations of Constellation Energy Group, Inc.

E. Follin Smith
Executive Vice President and Chief Financial Officer

Date: May 7, 2004

Exhibit 32(c)

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

I, Frank O. Heintz, President and Chief Executive Officer of Baltimore Gas and Electric Company, certify pursuant to 18 U.S.C. Section 1350 adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that to my knowledge:

(i) The accompanying Quarterly Report on Form 10-Q for the quarter ended March 31, 2004 fully complies with the requirements of Section 13(a) or Section 15(d) of the Securities Exchange Act of 1934, as amended; and

(ii) The information contained in such report fairly presents, in all material respects, the financial condition and results of operations of Baltimore Gas and Electric Company.

Frank O. Heintz
President and Chief Executive Officer

Date: May 7, 2004

Exhibit 32(d)

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

I, E. Follin Smith, Senior Vice President and Chief Financial Officer of Baltimore Gas and Electric Company, certify pursuant to 18 U.S.C. Section 1350 adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that to my knowledge:

(i) The accompanying Quarterly Report on Form 10-Q for the quarter ended March 31, 2004 fully complies with the requirements of Section 13(a) or Section 15(d) of the Securities Exchange Act of 1934, as amended; and

(ii) The information contained in such report fairly presents, in all material respects, the financial condition and results of operations of Baltimore Gas and Electric Company.

E. Follin Smith
Senior Vice President and Chief Financial Officer

Date: May 7, 2004

May 7, 2004

VIA ELECTRONIC TRANSMISSION

Securities and Exchange Commission
Division of Corporation Finance
Attention: Filing Desk
450 Fifth Street, N.W.
Washington, D.C. 20549

Re: File Nos. 1-12869 and 1-1910
Form 10-Q March 31, 2004

Ladies and Gentlemen:

We are transmitting to you by EDGAR the combined Form 10-Q of Constellation Energy Group, Inc. and Baltimore Gas and Electric Company for the quarter ended March 31, 2004 for filing under the Securities Exchange Act of 1934.

Kindly direct any notice concerning the Form 10-Q or any questions or comments regarding our filing to me or Charles A. Berardesco at (410) 783-3011.

Our fax number for any communication is (410) 783-3018.

Very truly yours,

E. Follin Smith

Enclosure

cc: C. A. Berardesco

EXHIBIT III

2004 INTERNAL CASH FLOW PROJECTION

Calvert Cliffs Nuclear Power Plant, Inc.
July 30, 2004

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	$201,200
Payable at Per Year (000)	$40,000

	2003 Actual '000	2004 Projected '000
Net Income	277,300	556,000
Less: Dividends Paid	(169,200)	(189,000)
Retained Earnings	108,100	367,000
Adjustments:		
Depreciation and Amortization	600,000	708,000
Deferred income Taxes	109,200	66,000
Investment tax credit	(7,300)	(7,000)
Allowance for funds Used during construction**	(3,000)	(2,000)
Total Adjustment	698,900	765,000
Internal Cash Flow	807,000	1,132,000
Average Quarterly Cash Flow	201,750	283,000

Constellation Energy Group

Underlying Assumptions for Projected Cash Flows

(1) 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.

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

(3) Accounting policies are consistent with those in effect December 31, 2003.

EXHIBIT IV

NARRATIVE STATEMENT

CURTAILMENT OF CAPITAL EXPENDITURES

Calvert Cliffs Nuclear Power Plant, Inc.
July 30, 2004

Constellation Energy Group

Curtailment of Capital Expenditures

Estimated construction expenditures including nuclear fuel and Allowance for Funds Used During Construction for the twelve months ended December 31, 2004 is $695 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.