Attachment

to

Application for Order and Conforming Administrative Amendments for License Transfer

December 16, 2003

Affidavit of Michael J. Wallace

STATE OF MARYLAND)

) ss

CITY OF BALTIMORE)

Michael J. Wallace, upon being first duly sworn according to law, under oath, deposes and states:

1. I am President and Chief Nuclear Officer of Constellation Generation Group, LLC. I have reviewed the information in the Confidential Addendum to the "Application for Order and Conforming Administrative Amendments to Transfer NRC Facility Operating License No. DPR-18" and have been authorized by Constellation Generation Group, LLC to file this Affidavit on its behalf with respect to such information.

2. The information in the Confidential Addendum contains confidential business information in the form of financial data on each page related to the operation of the R.E. Ginna Nuclear Power Plant that should be held in confidence by the Nuclear Regulatory Commission pursuant to 10 C.F.R. § 9.17(a)(4) and 10 C.F.R. § 2.790, because:

(i) This information is of a type that is customarily held in confidence by Constellation Generation Group, LLC and there is a rational basis for doing so because the information contains sensitive financial information concerning the projected revenues and operating expenses of Constellation Generation Group, LLC and other affiliated entities.

(ii) This information is being and has been held in confidence by Constellation Generation Group, LLC.

(iii) This information is being transmitted to the Nuclear Regulatory Commission in confidence.

(iv) This information is not available in public sources and could not be gathered readily from other publicly available information.

(v) Public disclosure of this information would create substantial harm to the competitive position of Constellation Generation Group, LLC and other affiliated entities by disclosing internal financial projections for these entities and confidential financial and corporate information to other parties whose commercial interests may be adverse to those of Constellation Generation Group, LLC and other affiliated entities.

3. Accordingly, Constellation Generation Group, LLC request that the designated documents be withheld from public disclosure pursuant to 10 C.F.R. 2.790(a)(4) and 10 CFR 9.17(a)(4).

LYNN J. CONANT
NOTARY PUBLIC
Baltimore City
MARYLAND
MY COMMISSION EXPIRES JULY 7 2007

Michael J. Wallace

Subscribed and sworn to me, a Notary Public, in and for the city and state above named, this 12th day of December 2003.

My Commission Expires: 7/7/07

(Notary Public)

December 16, 2003

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

In the Matter of	)	
	)	
Rochester Gas and Electric Corporation,	)	
	)	Docket No. 50-244
Constellation Generation Group, LLC, and	)	
	)	
R.E. Ginna Nuclear Power Plant, LLC	)	
	)	
(R.E. Ginna Nuclear Power Plant)	)	

APPLICATION FOR ORDER AND CONFORMING ADMINISTRATIVE AMENDMENTS TO TRANSFER NRC FACILITY OPERATING LICENSE NO. DPR-18

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LIST OF EXHIBITS

APPLICATION FOR ORDER AND CONFORMING ADMINISTRATIVE AMENDMENTS TO TRANSFER NRC FACILITY OPERATING LICENSE NO. DPR-18

I. INTRODUCTION AND DESCRIPTION OF THE PROPOSED TRANSACTION

Pursuant to Section 184 of the Atomic Energy Act of 1954, as amended (the "Act") and 10 C.F.R. §§ 50.80 and 50.90, Rochester Gas and Electric Corporation ("RG&E") and Constellation Generation Group, LLC ("CGG"), on behalf of its newly formed indirect subsidiary R.E. Ginna Nuclear Power Plant, LLC ("Ginna LLC"), hereby apply to the U.S. Nuclear Regulatory Commission ("NRC") for an order consenting to the transfer of Facility Operating License No. DPR-18 ("Operating License") for the R.E. Ginna Nuclear Power Plant ("Ginna Station") located in Ontario, New York to Ginna LLC.

This application further requests that conforming administrative amendments to the Operating License be issued to delete references to RG&E and authorize Ginna LLC as the new operator and owner to possess, use, and operate Ginna Station, and to possess and use related licensed materials under the applicable conditions and authorizations included in the current Operating License. This application does not request any amendments to the facility Operating License other than those administrative amendments necessary to reflect Ginna LLC as the new operator and owner. This application does not request approval of any physical changes in the unit, or any changes to the conduct of operations. After transfer of the license, the unit will continue to be operated and maintained in accordance with the current licensing basis.

Marked-up pages showing the requested changes to the Operating License are provided in Exhibit 1 to this application. If any other license amendments that might be issued prior to the license transfer affect the proposed conforming amendments, the parties will notify the NRC and supplement this application to show the new marked-up pages. Pursuant to 10 C.F.R. § 2.1315, these amendments involve no significant hazards considerations because the application does no more than conform the license to reflect the transfer action. In this regard, the closing of the transaction is conditioned on the NRC approving RG&E's pending license renewal application for Ginna Station by renewing the operating license for an additional 20 years beyond the current expiration date of September 18, 2009. Accordingly, the conforming license amendments to reflect the proposed license transfer would be to the renewed operating license following its issuance, if approved, by the NRC.

RG&E and CGG have entered into an Asset Purchase Agreement (the "Agreement"), dated as of November 24, 2003, under which RG&E will transfer its operating and ownership interest in Ginna Station to CGG. CGG will assign all of its interests, rights and obligations under the Agreement to Ginna LLC.[1] This transaction is part of the ongoing restructuring of the electric utility industry in the State of New York.

Ginna Station is a two loop pressurized water reactor, rated at 490 megawatts electric ("MWe"), located on the south shore of Lake Ontario in Wayne County, New York, approximately 20 miles northeast of Rochester, New York. RG&E is currently the sole owner and operator of Ginna Station.

RG&E is a New York corporation engaged principally in the generation of electricity as well as the purchase, transmission, distribution, and sale of electric power and natural gas in western New York State. RG&E operates under the general regulatory supervision of the New York State Public Service Commission ("NYPSC") and, for its wholesale electricity sales and related interstate activities, RG&E is subject to regulation by the Federal Energy Regulatory

[1] A copy of the Agreement is attached as Exhibit 2. The Agreement includes numerous schedules, exhibits and ancillary agreements totaling hundreds of pages that are not being provided with this application. Copies of this information can be made available upon request.

Commission ("FERC"). RG&E recovers its costs of generating electricity through rates subject to the regulatory authority of the NYPSC and FERC.

RG&E is a wholly owned indirect subsidiary of Energy East Corporation ("Energy East"). However, RG&E retains its distinct corporate existence and remains the sole operating owner and licensee for Ginna Station.

This application addresses issues central to the NRC's review of a direct license transfer request, including the nature and purpose of the proposed transaction, the financial and technical qualifications of Ginna LLC as the new owner and operator, Ginna LLC's ability to provide decommissioning funding assurance, and the absence of foreign control or domination over Ginna LLC and its affiliates. In the following sections, the applicants demonstrate that Ginna LLC will be financially and technically qualified to own and operate Ginna Station, and will provide decommissioning funding assurance that meets the NRC's requirements under 10 C.F.R. § 50.75. In short, the proposed transfer satisfies the NRC's standards for approval of a license transfer under 10 C.F.R. § 50.80.

II. NATURE AND PURPOSE OF THE PROPOSED TRANSACTION

On November 24, 2003, RG&E and CGG executed the Agreement for Ginna Station. Pursuant to the Agreement, RG&E will transfer its 100% ownership interest in Ginna Station and operating authority to CGG. CGG will assign all of its interests, rights and obligations under the Agreement to its subsidiary, Ginna LLC.

The closing of the transaction will take place on the Closing Date, as defined in the Agreement, once all conditions precedent are satisfied and all required regulatory approvals are obtained. On and after the Closing Date (and subject to NRC's consent and license amendments):

(a) Ginna LLC will assume title to the acquired assets in the Ginna Station facility including all equipment, spare parts, fixtures, inventory, fuel and other property necessary for the operation and maintenance of Ginna Station.

(b) Ginna LLC will make offers of employment to all Ginna Station employees, as described in the Agreement.

(c) Ginna LLC will assume responsibility for the operation, maintenance, and eventual decommissioning of Ginna Station, including responsibility for the management, storage, removal, transportation and disposal of spent nuclear fuel, as described in the Agreement.

(d) At closing, RG&E will transfer qualified and non-qualified decommissioning funds for Ginna Station to decommissioning trust funds established by Ginna LLC. The value of these transferred funds at closing is estimated to meet the NRC minimum requirements for prepayment of Ginna LLC's decommissioning obligation, as further discussed in Section III.H of this application. After closing, Ginna LLC will be responsible for all Ginna Station decommissioning activities, as well as the decommissioning costs, and the decommissioning obligations of RG&E will be extinguished.

No physical changes to the plant are being proposed as part of this application. The conforming amendments that are being requested are limited to those amendments necessary to reflect the new owner and its organization, and to delete references to the entity that is transferring its interest. Ginna LLC will assume all regulatory commitments and will continue to comply with the current licensing basis of the facility.

The purpose of this transaction is to allow the acquisition of Ginna Station by a technically and financially strong entity that has a long-term commitment to the safe and reliable generation of nuclear power. Upon closing CGG through its affiliates will own and operate five nuclear reactor units at three sites located in the United States.

III. INFORMATION REQUIRED BY 10 C.F.R. §§ 50.33 AND 50.80 FOR TRANSFERS OF CONTROL

A. NAME OF PROPOSED NEW LICENSEE

R.E. Ginna Nuclear Power Plant, LLC ("Ginna LLC").

B. ADDRESS OF THE PROPOSED NEW LICENSEE

1997 Annapolis Exchange Parkway, Suite 500
Annapolis, MD 21401

C. DESCRIPTION OF BUSINESS

Ginna LLC is a limited liability company newly formed to acquire and operate Ginna Station. Ginna LLC will be an Exempt Wholesale Generator ("EWG") under applicable FERC regulations engaged in the generation and sale of electric energy to wholesale customers.

D. CORPORATE INFORMATION

1. State of Incorporation and Principal Place of Business

Ginna LLC is a limited liability company organized and existing under the laws of the State of Maryland. Ginna LLC's principal place of business is New York State.

2. Names, Addresses, and Citizenship of Directors and Principal Officers

Ginna LLC will be managed by a Board of Directors. The names and addresses of the Directors and Principal Officers of Ginna LLC, all of whom are U.S. citizens, are listed below:

Directors

Michael J. Wallace	Chairman of the Board
Business Address	1997 Annapolis Exchange Parkway, Suite 500 Annapolis, MD 21401

Maria A. Korsnick	Director
Business Address	1997 Annapolis Exchange Parkway, Suite 500 Annapolis, MD 21401

Principal Officers

Michael J. Wallace	President and Chief Nuclear Officer
Business Address	1997 Annapolis Exchange Parkway, Suite 500 Annapolis, MD 21401
Maria A. Korsnick	Vice President
Business Address	1997 Annapolis Exchange Parkway, Suite 500 Annapolis, MD 21401
Stephen A. Mormann	Treasurer
Business Address	1997 Annapolis Exchange Parkway, Suite 500 Annapolis, MD 21401
Steven L. Miller	Secretary
Business Address	750 E. Pratt Street Baltimore, MD 21202
James M. Petro, Jr.	Assistant Secretary
Business Address	750 E. Pratt Street Baltimore, MD 21202

3. No Foreign Ownership, Control, or Domination

CGG, its parent company Constellation Energy Group, Inc., and Ginna LLC are not owned, controlled, or dominated by an alien, foreign corporation, or foreign government.

4. No Agency

In seeking to become the licensed owner and operator of Ginna Station, Ginna LLC is not acting as the agent or representative of any other person.

5. Related Entities

Ginna LLC is an indirect, wholly-owned subsidiary of CGG. CGG is a wholly-owned subsidiary of Constellation Energy Group, Inc. ("Constellation"). CGG serves a company headquarters function for Constellation's national fleet of generating plants with approximately 12,125 megawatts of generating capacity. Of this 12,125 megawatts of generating capacity, CGG indirectly owns and controls the consolidated assets, liabilities, and net worth of approximately 3,235 megawatts of nuclear generation. CGG's nuclear operation is comprised of over $3 billion of assets, approximately $925 million of net worth, and approximately $1 billion in annual revenue. Through ownership of CGG's wholly-owned subsidiary, Constellation Nuclear Power Plants, Inc., it will have an indirect ownership interest in Ginna LLC. These corporate relationships are depicted in Exhibit 3.

Constellation is a publicly traded utility holding company incorporated in 1995 under the laws of the State of Maryland. Constellation is engaged in competitive wholesale and retail energy supply, including generation, distribution and marketing. A copy of Constellation's 2002 Annual Report and 2002 10-K Form are included as Exhibit 4.

E. NRC LICENSES INVOLVED

The proposed transaction involves NRC Facility Operating License No. DPR-18 for Ginna Station.

F. TECHNICAL QUALIFICATIONS

Exhibit 5 is a proposed organization chart illustrating the management structure and reporting relationships for Ginna Station that will become effective on the effective date of the license transfer. When the proposed transfer of the Ginna Station Operating License becomes effective, Ginna LLC will assume responsibility for, and control over, the operation and maintenance of Ginna Station. Ginna LLC will make offers of employment with comparable compensation and benefits to all of RG&E's existing on-site nuclear organization at Ginna Station in accordance with the Agreement.

The Ginna Station on-site nuclear organization will report operationally through the Site Vice President to Mr. Michael J. Wallace, who is CGG's President and Chief Nuclear Officer. Mr. Wallace is responsible for all nuclear activities at CGG and upon transfer of the Ginna Station Operating License will assume, in addition to his current duties, the position of President and Chief Nuclear Officer of Ginna LLC. Mr. Wallace is a career nuclear professional with over 30 years of direct relevant experience in the construction, management, and safe operation of U.S. nuclear power plants.

It is expected that the vast majority of Ginna Station's plant staff, including senior managers, will remain essentially unchanged by the transfer. However, as is common for the management and staff at operating nuclear power plants, individuals routinely transfer to other positions within the same company, retire, resign, or transfer to positions at other sites. Thus, it is to be expected that additional experienced personnel may join the site organization during the period leading up to and after the proposed license transfer. Prior to the transfer, decisions regarding such changes will be made by RG&E, and following the transfer, such decisions will be made by Ginna LLC. Ginna LLC will ensure that following the transfer, new personnel meet all existing qualifications requirements in accordance with the Ginna Station Operating License and Technical Specifications. The guiding principle that will govern Ginna LLC's management of Ginna Station will be to assure that it manages, operates, and maintains Ginna Station safely and in accordance with the conditions and requirements established by the NRC.

The existing on-site operations, maintenance and technical support organizations for Ginna Station will continue to perform their functions as part of the Ginna LLC organization. The functions, responsibilities, and reporting relationships of these organizations, especially as they relate to activities important to the safe operation of Ginna Station, will continue to be clear and unambiguous, and the performance of these organizations will be essentially unaffected by the transfer. Moreover, engineering support for Ginna Station is currently provided by a dedicated engineering organization that is an integral part of the site organization that will be transferred to Ginna LLC.

As detailed in Section 2.1 of the Agreement, RG&E will transfer to Ginna LLC those assets related to Ginna Station that are sufficient to allow Ginna LLC to operate Ginna Station safely in accordance with NRC requirements. Section 2.1 of the Agreement provides an extensive listing of assets in addition to plant and equipment that will be transferred, such as books, operating records, safety, maintenance, and operating manuals, engineering design plans, documents, blueprints and as-built plans, specifications, procedures, and other similar items. The records that the NRC requires a licensee to maintain are currently located and maintained at Ginna Station or under Ginna Station's control. Section 2.2 of the Agreement sets forth those assets specifically excluded from the proposed license transfer to Ginna LLC, including certain switchyard facilities and related transmission and interconnection assets.

Ginna LLC will not be relying on other organizations to establish its technical qualifications. Nevertheless, the extensive experience and technical capabilities of CGG are a valuable resource available to Ginna LLC. CGG and its nuclear subsidiaries currently own and operate four operating power reactor units at its Calvert Cliffs and Nine Mile Point plants. This level of experience and capability in an affiliated company provides added assurance that Ginna

LLC will have the requisite technical qualifications necessary to conduct licensed activities at Ginna Station.

G. FINANCIAL QUALIFICATIONS

Ginna LLC will meet the financial qualification requirements for a "non-electric utility" licensee pursuant to 10 C.F.R. § 50.33(f). As set forth below, Ginna LLC will be financially qualified to own and operate Ginna Station.

1. Projected Operating Revenues and Operating Costs

Ginna LLC will possess, or will have reasonable assurance of obtaining, the funds necessary to cover estimated operating costs for the period of the license in accordance with 10 C.F.R. § 50.33(f)(2), as well as the guidance in the Standard Review Plan for Power Reactor Licensee Financial Qualifications and Decommissioning Funding Assurance (NUREG-1577, Rev. 1) ("Standard Review Plan"). In accordance with the Standard Review Plan, projected income statements for the operation of Ginna Station for the five-year period following the Closing Date have been prepared by CGG for NRC review. The proprietary projected income statements are being submitted with the CGG Confidential Addendum to the Application, supported by the CGG affidavit transmitted with this Application, that provides justification for withholding the statements from public disclosure. The non-proprietary projected income statements are included in Exhibit 6. In addition to the projected income statements, CGG is providing a Ginna LLC projected opening balance sheet showing its anticipated assets, liabilities and capital structure expected as of the Closing Date. The proprietary projected opening balance sheet is being submitted with the CGG Confidential Addendum to the Application, supported by the CGG affidavit transmitted with this Application, that provides justification for withholding the statements from public disclosure. A non-proprietary version of the opening balance sheet is included in Exhibit 7.

The projected income statements are based in part on a Power Purchase Agreement ("PPA") between Constellation Power Source, Inc. ("CPS") and RG&E that will provide Ginna LLC with a substantial portion of its revenue over the next ten years. The PPA is included as Exhibit 8. CPS is Constellation's merchant subsidiary that markets energy and ancillary services. A back-to-back contract will be executed between CPS and Ginna LLC to provide revenue to Ginna LLC that results from the sale of capacity and energy from Ginna Station. Under the PPA executed as part of this transaction, CPS will sell 90 percent of the output from Ginna Station to RG&E for a 10-year period at prices established in the PPA. The remaining 10 percent of the output will be sold into the power market.

The projected income statements prepared by CGG provide the total estimated annual operating costs for Ginna Station. They also indicate that the source of funds to cover these operating costs will be operating revenues. The projected income statements include various projections by CGG for plant operations, the prices for capacity and energy under the PPA and in the market, fuel expenses, and depreciation, including the effects of anticipated capital additions.

The Ginna LLC projected income statements demonstrate that the anticipated revenues from sales of capacity and energy from Ginna Station provide reasonable assurance of an adequate source of funds to meet Ginna LLC's operating expenses for Ginna Station during the five year period following the Closing Date. Additionally, the projected income statements set forth the projected annual level of cash flow from operations, before interest and taxes, and also provide the projected annual level of cash flow after covering both capital expenditures and nuclear fuel expenditures. Operating revenues from Ginna Station are projected to produce sufficient cash flow, before interest and taxes, to cover both capital expenditures and nuclear fuel expenditures.

2. Additional Sources of Funds

Constellation operates a cash pool for all of its subsidiaries. Ginna LLC will be a member of the cash pool for as long as it is a subsidiary of Constellation. Each day, each member of the cash pool provides Constellation with its cash position for that day. Each day, the member also transfers to the pool any excess cash, which is invested. On any day, if members need more cash than is available from the pool, Constellation sells commercial paper to the public markets. Money from the sale of commercial paper is wired into another member's account later the same day. When a member borrows money from the pool, the amount is recorded on a master demand note, and is payable with interest to Constellation upon 24 hours demand. A form of Master Demand Note is enclosed as Exhibit 9.

The cash pool and Constellation's commercial paper program are extremely liquid and can provide cash to meet operating and maintenance expenses usually on the same day such needs are identified. Currently, Constellation has a $2.5 billion commercial paper program rated A2/P2 by Standard & Poor's and Moody's, respectively. It currently has credit agreements and committed bank lines of credit totaling $1.5 billion to support its commercial paper program. Constellation has not issued commercial paper since April, 2002 and continues to maintain a zero balance. Therefore, the entire $1.5 billion (less any letters of credit issued) is available to support the issuance of commercial paper.

Ginna LLC will execute an inter-company credit agreement with its parent, Constellation, whereby Constellation will provide Ginna LLC with cash needed by Ginna LLC that is not available from the cash pool to protect the public health and safety. A form Inter-Company Credit Agreement between Constellation and Ginna LLC is enclosed as Exhibit 10.

These arrangements provide assurance that Ginna LLC will have sufficient funds available to meet its operating and maintenance expenses during a six-month outage of Ginna Station. Such an extended outage is the benchmark six-month outage defined by NRC guidance in the Standard Review Plan with respect to providing added assurance of financial qualifications.

The projected income statements contained in this application provide reasonable assurance that Ginna LLC will be financially qualified to own and operate Ginna Station. Moreover, the additional sources of funds discussed above provide assurance that Ginna LLC will have funds sufficient to pay the fixed costs of an outage lasting six months, as suggested in the guidance provided in the Standard Review Plan.

H. DECOMMISSIONING FUNDING

As noted above, RG&E expects to transfer to Ginna LLC at closing an aggregate amount of decommissioning funds that will meet the NRC minimum funding requirement with credit for two-percent real earnings, as permitted by the NRC regulations, assuming the renewal of Ginna Station's Operating License which is a condition of closing.[2] The amount of funds to be transferred is defined as the "Decommissioning Target" in the Agreement. The decommissioning funds will be held in an external trust segregated from Ginna LLC's assets and outside its administrative control. The terms of the Ginna LLC decommissioning trust agreement will comply with the NRC's final rule on Decommissioning Trust Provisions (67 Fed. Reg. 78332) which becomes effective December 24, 2003.

[2] See Sections 7.1(o) and 7.2(l) of the Agreement.

On the closing date the funds in RG&E's qualified decommissioning trust fund will be transferred to Ginna LLC, and RG&E will also transfer to Ginna LLC so much of its nonqualified decommissioning trust funds as is necessary, when combined with the amount in RG&E's qualified trust fund, to meet the Decommissioning Target amount agreed upon by RG&E and CGG in the Agreement. Upon the closing of the sale and the transfer of the Decommissioning Target amount to Ginna LLC, RG&E's decommissioning trust will be terminated and the balance of the nonqualified funds will be retained by RG&E and applied as directed by the NYPSC.

Under the Agreement, the Decommissioning Target amount to be transferred at closing is projected to be approximately $201.6 million assuming a June 30, 2004 closing. The precise amount will vary depending on the actual closing date. The full amount of the decommissioning funds transferred to Ginna LLC at closing will be in cash or cash equivalents, and will be available to Ginna LLC for decommissioning as defined under the NRC's decommissioning regulations. As shown in Exhibit 11, when a two-percent annual real rate of earnings is credited to the Decommissioning Target amount through the expected term of the renewed license in 2029,[3] as permitted by 10 C.F.R. § 50.75(e)(1)(i), the value of the decommissioning funds at closing is estimated to meet the NRC minimum requirement under 10 C.F.R. § 50.75(c) for prepayment, without the need for additional contributions Accordingly, as demonstrated by Exhibit 11, Ginna LLC will provide adequate decommissioning funding assurance in accordance with 10 C.F.R. § 50.75(e)(1)(i) through prepayment of the decommissioning obligation.

[3] As discussed in Section IV.J below, closing of this transaction is conditioned on the NRC having issued a renewed operating license for Ginna Station for a period of not less than 20 years beyond its original license term of 2009. Thus it is appropriate to use the expected term of the renewed license in the decommissioning funding calculations in this application for purposes of demonstrating that the proposed new licensee will provide adequate assurance of decommissioning funding.

I. ANTITRUST CONSIDERATIONS

In accordance with the NRC's decision in *Kansas Gas and Electric Company* (Wolf Creek Generating Station, Unit 1), CLI-99-19, 49 NRC 441, 468 (1999) and the recent amendments to 10 C.F.R. § 50.80, 65 FR 44649 (July 19, 2000), antitrust reviews of post-operating license transfer applications are not required under the Act. For this reason, the NRC need not consider any antitrust issues in connection with this application.

J. RESTRICTED DATA, CLASSIFIED NATIONAL SECURITY INFORMATION, AND LACK OF FOREIGN OWNERSHIP

This application does not contain any Restricted Data or classified National Security Information, and it is not expected that any licensed activities at Ginna Station will involve any such information. However, pursuant to 10 C.F.R. § 50.37, in the event that such information does become involved, Ginna LLC agrees that it will (1) appropriately safeguard such information and (2) not permit any individual to have access to such information unless, and until, (a) the Office of Personnel Management ("OPM") has investigated the character, associations, and loyalty of any such individual, (b) OPM has reported to the NRC on the result of such an investigation, and (c) the NRC has determined that permitting such person to have access to such information will not endanger the common defense and security of the United States.

Constellation, CGG and Ginna LLC are not, and following implementation of the proposed license transfer will not be owned, controlled, or dominated by an alien, foreign corporation, or foreign government. In addition, Ginna LLC is not functioning as an agent or representative of another person with respect to this application.

K. ENVIRONMENTAL CONSIDERATIONS

The proposed Ginna Station license transfer and conforming administrative amendments fall within the categorical exclusion appearing at 10 C.F.R. § 51.22(c)(21), so that neither an Environmental Assessment nor an Environmental Impact Statement is required with respect to those actions. Moreover, the proposed license transfer does not involve any amendments to the license or other changes that would directly affect the actual operation of Ginna Station in any substantive manner. The proposed license transfer and amendments do not involve an increase in the amounts, or a change in the types, of any radiological effluents that may be allowed to be released off-site. Further, no increase in the individual or cumulative occupational radiation exposure is expected. For these reasons, the proposed license transfer and amendments involve no significant environmental impact.

L. NO SIGNIFICANT HAZARDS CONSIDERATION

The only actions sought in this application with respect to the license is the transfer of ownership of Ginna Station pursuant to 10 C.F.R. § 50.80 and administrative amendments under 10 C.F.R. § 50.90 solely to conform the license to reflect the change in ownership of Ginna Station. Pursuant to the NRC's generic determination in 10 C.F.R. §2.1315, the requested amendments therefore involve "no significant hazards consideration."

Because the closing of the transaction is conditioned on the NRC's issuance of a renewed license for Ginna Station, the license that will be amended to reflect the proposed license transfer will be the renewed Operating License following NRC approval, if granted, of RG&E's pending license renewal application and issuance of the renewed license. Thus the conforming administrative amendments will relate to the expected renewed license if approved by the NRC.

IV. ADDITIONAL INFORMATION REGARDING SPECIFIC REGULATORY REQUIREMENTS, PLANS, PROGRAMS, AND PROCEDURES

A. OFFSITE POWER

Offsite power to Ginna Station is currently provided over transmission and interconnection facilities owned and operated by RG&E. As part of the sale of Ginna Station, RG&E has entered into an Interconnection Agreement to continue to provide interconnection services to Ginna Station after the effective date of the proposed license transfer. A copy of the Interconnection Agreement is attached as Exhibit 12. In addition, RG&E is obligated to provide offsite power services to Ginna Station pursuant to an NYPSC-approved tariff. These arrangements will provide assurance that Ginna LLC will continue to have reliable offsite power meeting applicable NRC requirements.

Functionally, the interconnection of RG&E's transmission and interconnection facilities with Ginna Station will not change as a result of the proposed license transfer. Pursuant to the Interconnection Agreement, Ginna LLC will maintain the facilities and equipment located between the generating facility and the points of interconnection that are necessary to physically and electrically interconnect Ginna Station to RG&E's interconnection facilities and transmission system. The Interconnection Agreement further provides that RG&E will operate, maintain and control its interconnection facilities in a manner that maintains compliance with the NRC's maintenance rule and other applicable NRC requirements and commitments. As the licensee, Ginna LLC will remain responsible for ensuring compliance with all applicable NRC requirements.[4]

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[4] In accordance with the Agreement, RG&E will retain ownership of the 115 kV switchyard ("Station 13A") since most of the 115 kV switchyard equipment and operations at Station 13A are integral to the interconnection of Ginna Station with the RG&E transmission system. Although Ginna LLC will not own the Station 13A property, it will have appropriate control as necessary to satisfy applicable NRC requirements and commitments through the existing security and emergency plans as well as written protocols to be established by RG&E and Constellation

The Interconnection Agreement will enable Ginna LLC to have access to the transmission facilities subject to the operational control of the New York Independent System Operator ("NYISO"). The NYISO, which began operating on November 18, 1999, has responsibility for, and independent control over, operation of the electric power transmission grid in the State of New York. This power grid, which includes the transmission system of RG&E as well as the other former member systems of the New York Power Pool ("NYPP"), was previously operated by the NYPP.[5] Consistent with FERC requirements, the NYISO provides all market participants with equal access to unbundled electric transmission service throughout the State of New York. The NYISO monitors the capacity that is available on the system and centrally dispatches generating units to meet load, provide necessary ancillary services, and accommodate bilateral transactions while not violating any security-related constraints.

The NYISO exercises operational control over the transmission facilities of the member systems, including RG&E's transmission facilities. The Interconnection Agreement, through access to the transmission facilities subject to the operational control of the NYISO, will provide an avenue for either Ginna LLC or its customers to obtain through separate arrangements all of the services, including transmission services, necessary to participate in the market for the sale of power from the facility.

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relating to access, control, safety, security, and evacuation with respect to each other's property, including Station 13A.

5 On January 31, 1997, eight members of the NYPP submitted for FERC approval an application for authorization to establish an independent system operator ("ISO"). By order issued on June 30, 1998, FERC authorized the establishment of the New York Independent System Operator ("NYISO"). *Central Hudson Gas & Electric Corp., et al.*, 83 FERC ¶ 61,352 (1998), *reh'g*, 87 FERC ¶ 61,135 (1999). On February 5, 1999, the NYPP member systems filed an application with FERC requesting authorization to transfer control over certain transmission facilities to the NYISO. FERC authorized the requested transfer on April 30, 1999. 87 FERC ¶ 61,135.

B. EMERGENCY PLANNING

Upon consummation of the proposed license transfer, Ginna LLC will assume authority and responsibility for functions necessary to fulfill the emergency planning requirements specified in 10 C.F.R. § 50.47(b) and Part 50, Appendix E. Any changes made to the existing Ginna Station Emergency Plan developed and implemented by the current licensee will be made in accordance with 10 C.F.R. § 50.54(q). It is anticipated that no changes will be made that will result in a decrease in the effectiveness of the Plan, and that the Plan will continue to meet the standards of 10 C.F.R. § 50.47(b) and the requirements of Appendix E of Part 50. Any specific emergency plan changes will be submitted to the NRC within 30 days after the changes are made, pursuant to 10 C.F.R. § 50.54(q) and Appendix E, Section V.

If RG&E or Ginna LLC identify any proposed changes that would decrease the effectiveness of the approved Emergency Plan, then application will be made to the NRC and such proposed changes will not be implemented until approved. Determinations as to whether any proposed changes would result in a decrease in effectiveness will be made in accordance with RG&E's currently approved plan, programs, and procedures.

No substantive changes are anticipated to be made to the existing emergency planning organization. Currently, RG&E owns and operates the Emergency Operations Facility ("EOF"). Upon closing, Ginna LLC will lease the EOF from RG&E and assume responsibility for its operation in accordance with the Ginna Station Emergency Plan. Existing agreements for support from organizations and agencies not affiliated with RG&E will be assigned to Ginna LLC. RG&E will notify the parties to such agreements in advance of the proposed license transfer, and will advise those parties of Ginna LLC's responsibility for management and operation of Ginna Station, effective as of the Closing Date. In sum, the proposed license transfer will not affect compliance with the emergency planning requirements.

C. EXCLUSION AREA

Upon the transfer from RG&E to Ginna LLC, Ginna LLC will own or control all real property within the Exclusion Area of Ginna Station. Ginna LLC will have authority to determine and control all activities within the Exclusion Area for Ginna Station, including the right to control activities and remove or exclude personnel and property from the Exclusion Area.

D. SECURITY PLAN

Upon consummation of the proposed license transfer, Ginna LLC will assume authority and responsibility for the functions necessary to fulfill the security planning requirements specified in 10 C.F.R. Part 73. Ginna LLC will assume the existing NRC-approved Physical Security, Guard Training and Qualification, and Safeguards Contingency plans developed and implemented by the current licensee, as well as RG&E's commitments in response to the applicable NRC Security Orders.

Any changes to the plans will be made in accordance with 10 C.F.R. § 50.54(p). It is anticipated that no changes will be made as a result of the license transfer that will lead to a decrease in the effectiveness of the plan, and the plan will continue to meet the standards of 10 C.F.R. Part 73, Appendix C. Any specific security plan changes will be submitted to the NRC within two months after the changes are made, pursuant to 10 C.F.R. § 50.54(p)(2). If RG&E or Ginna LLC identify any proposed changes that would decrease the effectiveness of the approved security plan, then application to the NRC will be made, and such proposed changes will not be implemented until approved by the NRC. Determinations as to whether any proposed changes would result in a decrease in effectiveness will be made in accordance with RG&E's currently approved security plan, programs, and procedures.

It is not anticipated that substantive changes will be made to the existing security organization as a result of the proposed license transfer to Ginna LLC. Existing agreements for support from organizations and agencies not affiliated with RG&E will be assigned to Ginna LLC. RG&E will notify the parties to such agreements in advance of the proposed license transfer to Ginna LLC, and will advise those parties of Ginna LLC's responsibility for management and operation of Ginna Station. In sum, the proposed transfer will not affect compliance with physical security requirements.

E. QUALITY ASSURANCE PROGRAM

Upon the proposed license transfer, Ginna LLC will assume authority and responsibility for the functions necessary to fulfill the quality assurance requirements of 10 C.F.R. Part 50, Appendix B. Any changes made to Ginna Station's existing Quality Assurance Plan ("QAP") developed and implemented by RG&E will be made in accordance with 10 C.F.R. § 50.54(a). It is not anticipated that any changes will be made as a result of the proposed license transfer that would reduce a commitment in the QAP previously accepted by the NRC. If Ginna LLC identifies any reduction in a commitment in the QAP, then application to the NRC will be made and such proposed reduction will not be implemented until approved by the NRC. Determinations as to whether any commitments would be reduced will be made in accordance with RG&E's currently approved plan, programs, and procedures.

It is not anticipated that any substantive changes will be made to the existing QAP organization as a result of the transfer of the license to Ginna LLC.

F. UPDATED FINAL SAFETY ANALYSIS REPORT

With the exception of areas discussed in this application, the proposed license transfer and conforming administrative amendments will not change or invalidate information presently appearing in Ginna Station's Updated Final Safety Analysis Report ("UFSAR"), and all currently existing licensing basis commitments will remain in effect. Changes necessary to accommodate the proposed license transfer and conforming administrative license amendments will be incorporated into the UFSAR, in accordance with 10 C.F.R. § 50.71(e), following the NRC's approval of this request for consent to the proposed license transfer.

G. TRAINING

The Ginna Training Center will be transferred to Ginna LLC and all or substantially all staff members currently working at this facility will be offered employment with Ginna LLC. The proposed license transfer will not affect compliance with the operator re-qualification program requirements of 10 C.F.R. § 50.54(i-1) and related sections, or maintenance of the INPO accreditation for Ginna Station licensed and non-licensed operator training. Upon consummation of the license transfer, Ginna LLC will assume responsibility for implementation of present training programs. Changes to the programs resulting from the license transfer will not decrease the scope or effectiveness of the approved operator re-qualification program without the specific authorization of the NRC, in accordance with 10 C.F.R. § 50.54(i).

H. INDEMNITY AND NUCLEAR INSURANCE

In accordance with 10 C.F.R. § 140.92, Art. IV.2, Ginna LLC and RG&E request NRC approval of the assignment and transfer of the interests of RG&E in the Price Anderson Indemnity Agreement for Ginna Station to Ginna LLC upon consent to the proposed license transfer. Ginna LLC's Projected Income Statements and financial arrangements with

Constellation will provide adequate assurance that Ginna LLC will be able to pay a total annual retrospective premium of $10 million for Ginna Station pursuant to 10 C.F.R. §§ 140.21(e)-(f). Prior to the license transfer, Ginna LLC will obtain all required nuclear property damage insurance pursuant to 10 C.F.R. § 50.54(w) and nuclear energy liability insurance pursuant to Section 170 of the Act and 10 C.F.R. Part 140.

I. STANDARD CONTRACT FOR DISPOSAL OF SPENT NUCLEAR FUEL

On the Closing Date, Ginna LLC will assume title to and responsibility for storage and disposal of spent or used nuclear fuel at Ginna Station. RG&E will assign, and Ginna LLC will assume, the rights and obligations of RG&E under the Standard Contract with the Department of Energy ("DOE"), except that RG&E will remain liable for any fees payable to DOE under the Standard Contract for electricity generated and sold prior to the Closing Date.

J. LICENSE RENEWAL

RG&E submitted a license renewal application to the NRC by letter dated July 30, 2002. The NRC's technical and environmental reviews of the license renewal application have proceeded on schedule. A draft environmental impact statement (draft Supplement 14 to NUREG-1437) was issued by the NRC in June 2003, and the NRC Staff's Safety Evaluation Report was issued in October 2003. The NRC's technical and environmental reviews of the license renewal application are continuing. According to the NRC's published schedule, upon the successful completion of the NRC's license renewal reviews, a renewed Operating License is scheduled to be approved by early June 2004.

As provided in Sections 7.1(o) and 7.2(l) of the Agreement, closing is conditioned on the NRC having issued a renewed Operating License for Ginna Station for a period of not less than 20 years beyond its original license term of 2009. The Agreement also provides (at Section 6.19) that Ginna LLC will maintain and operate the facility in accordance with licensing basis commitments, which include the commitments made in connection with RG&E's license renewal application. Accordingly, adequate measures are in place to ensure that the new licensee will fulfill the commitments made in the license renewal process. It is also important to note, in this connection, that Ginna LLC's affiliated companies have long been leaders in the license renewal arena, with Calvert Cliffs Nuclear Power Plant being the first plant to seek and obtain a renewed license.

K. OTHER REQUIRED REGULATORY APPROVALS

The proposed sale of Ginna Station to Ginna LLC is subject to the approval of FERC and the New York State Public Service Commission ("NYPSC"). RG&E and Ginna LLC are requesting FERC approval for the sale of jurisdictional assets pursuant to Section 203 of the Federal Power Act ("FPA"), and NYPSC approval for the transfer of assets pursuant to Section 70 of the New York Public Service Law. RG&E will also seek FERC acceptance of the Interconnection Agreement under Section 205 of the FPA. In addition, appropriate state rulings will be sought to permit Ginna LLC to obtain EWG status under applicable FERC regulations.

V. EFFECTIVE DATE

RG&E and Ginna LLC request that the NRC review this application on a timetable permitting issuance of the NRC Order consenting to the proposed license transfer as promptly as possible, and in any event by June 1, 2004 (assuming that issuance of a renewal license has been approved by that date). RG&E and Ginna LLC request that any needed license changes be approved with issuance of the Order, with implementation to be effective on the Closing Date. RG&E and Ginna LLC shall keep the NRC apprised of any significant changes in the status of other required regulatory approvals or developments affecting the schedule.

VI. CONCLUSION

For the foregoing reasons, the Commission should find that Ginna LLC is qualified to be the holder of the license for Ginna Station, and that the proposed license transfer will not be inimical to the common defense and security or result in any undue risk to public health and safety, and otherwise will be consistent with the requirements of the Act and the NRC regulations. Accordingly, and based upon the foregoing information, RG&E and Ginna LLC respectfully request that the NRC issue an Order approving: (1) the transfer of Facility Operating License No. DPR-18 for Ginna Station from RG&E to Ginna LLC; and (2) the associated conforming administrative license amendments.

I, Michael J. Wallace, being duly sworn, state that I am President and Chief Nuclear Officer, Constellation Generation Group, LLC ("CGG"), and that I am duly authorized to execute and file this application on behalf of CGG. To the best of my knowledge and belief, the statements contained in this document are true and correct. To the extent that these statements are not based on my personal knowledge, they are based upon information provided by other CGG employees and/or consultants. Such information has been reviewed in accordance with company practice and I believe it to be reliable.

Constellation Generation Group, LLC

Michael J. Wallace
President and
Chief Nuclear Officer

STATE OF: New York

COUNTY OF: Wayne

Subscribed and sworn to before me, a Notary Public, in and for the County and State above named, this 15th day of December, 2003.

Michalene A. Bunts

My Commission Expires: 1-11-07

MICHALENE A BUNTS
Notary Public, State of New York
Registration No. 01BU6018576
Monroe County
Commission Expires Jan 11, 2007

I, Dr. Robert C. Mecredy, being duly sworn, state that I am the Vice President, Nuclear Operations of Rochester Gas & Electric Corporation ("RG&E),, and that I am duly authorized to execute and file this application on behalf of RG&E. To the best of my knowledge and belief, the statements contained in this document are true and correct. To the extent that these statements are not based on my personal knowledge, they are based upon information provided by other RG&E employees and/or consultants. Such information has been reviewed in accordance with company practice and I believe it to be reliable.

Rochester Gas & Electric Corporation

Robert C Mecredy

Dr. Robert C. Mecredy
Vice President,
Nuclear Operations

STATE OF: New York

COUNTY OF: Wayne

Subscribed and sworn to before me, a Notary Public, in and for the County and State above named, this 15th day of December, 2003.

Michalene A. Bunts

My Commission Expires: 1-11-07

MICHALENE A BUNTS
Notary Public, State of New York
Registration No. 01BU6018576
Monroe County
Commission Expires Jan 11, 2007

EXHIBITS

Exhibit 1

EXHIBIT 1

Proposed Changes to the Facility Operating License
Associated with the Proposed Transfer of R.E. Ginna Nuclear Power Plant
from Rochester Gas and Electric Corporation to R.E. Ginna Nuclear Power Plant, LLC

I. Reason for the Change

The ownership of R.E. Ginna Nuclear Power Plant ("Ginna Station") located in Ontario, New York is being transferred from Rochester Gas and Electric Corporation ("RG&E") to R.E. Ginna Nuclear Power Plant, LLC ("Ginna LLC"), a wholly owned indirect subsidiary of Constellation Generation Group, LLC ("CGG"), necessitating the submittal of a conforming change to the Facility Operating License for the plant. The transfer in ownership is pursuant to an Asset Purchase Agreement ("Agreement") executed between CGG and RG&E on November 24, 2003. The proposed changes delete references to RG&E, as the owner and operator of Ginna Station, and replace them with references to "Ginna LLC."

II. Basis for the Change

After the license transfer, RG&E will retain no responsibility for the regulatory obligations contained in License No. DPR-18 for Ginna Station, as described in the Agreement. Accordingly, the entity to which that responsibility is being transferred, Ginna LLC, must be identified in the Facility Operating License.

III. Safety Assessment

The proposed changes to the Facility Operating License for Ginna Station identify Ginna LLC as the new owner and operator of the facility. No physical modifications are being made to plant systems or components nor are any significant changes in day-to-day operation of the unit being made. Therefore, the proposed changes are administrative in nature and will not adversely affect nuclear safety or safe plant operation.

IV. Description of the Proposed Changes

The proposed changes to the Facility Operating License for Ginna Station include the following: (1) the deletion of references to RG&E as operator or owner of Ginna Station as applicable; and (2) the authorization of Ginna LLC to possess, use and operate Ginna Station under essentially the same conditions and authorization included in the existing license. The actual wording changes (marked-up pages) associated with the conforming administrative amendments to the Ginna Station License are provided at the end of this Exhibit. The following changes to the Ginna Station License are proposed:

License Section and Page Number	Action Description
Title, Page 1	Delete "ROCHESTER GAS AND ELECTRIC CORPORATION" and replace it with "R.E. GINNA NUCLEAR POWER PLANT, LLC"
Section 2, Page 2	Strike "hereby" and replace it with "originally" and insert "and subsequently transferred to R.E. Ginna Nuclear Power Plant, LLC" immediately following the word "Corporation"
Section 2.A, Page 2	Strike "the Rochester Gas and Electric Corporation" and replace it with "R.E. Ginna Nuclear Power Plant, LLC" and strike "RG&E" and replace it with "Ginna LLC"
Section 2.B (first sentence), Page 2	Strike "RG&E" and replace it with "Ginna LLC"
Section 2.C(1), Page 3	Strike "RG&E" and replace it with "Ginna LLC"
Section 2.C(2), Page 3	Insert "83" representing the number of amendments issued to date
Date of Issuance, Page 4	Delete the date "December 10, 1984" and replace it with the new date of issuance.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, DC 20555

R.E. GINNA NUCLEAR POWER PLANT, LLC
~~ROCHESTER GAS AND ELECTRIC CORPORATION~~

DOCKET NO. 50-244

R.E. GINNA NUCLEAR POWER PLANT

FACILITY OPERATING LICENSE

License No. DPR-18

1. The Nuclear Regulatory Commission (the Commission) has found that:

   A. The application complies with the requirements of the Atomic Energy Act of 1954, as amended (the Act), and the regulations of the Commission set forth in 10 CFR Chapter I and all required notifications to other agencies or bodies have been duly made;

   B. Construction of the R.E. Ginna Nuclear Power Plant (the facility) has been substantially completed in conformity with Construction Permit No. CPPR-19, as amended, and the application, the provisions of the Act, and the rules and regulations of the Commission;

   C. The facility will operate in conformity with the application, the provisions of the Act, and the rules and regulations of the Commission;

   D. There is reasonable assurance (i) that the facility can be operated at power levels up to 1520 megawatts (thermal) without endangering the health and safety of the public; and (ii) that such activities will be conducted in compliance with the regulations of the Commission (except as exempted from compliance in Section 2.D below);

   E. The applicant is technically and financially qualified to engaged in the activities authorized by this operating license in accordance with the rules and regulations of the Commission;

   F. The applicant has furnished proof of financial protection that satisfies the requirements of 10 CFR Part 140; and

   G. The issuance of this license will not be inimical to the common defense and security or to the health and safety of the public.

and subsequently transferred to R.E. Ginna Nuclear Power Plant, LLC

originally

2. The Provisional Operating License dated September 19, 1969, is superseded by Facility Operating License No. DPR-18 ~~hereby~~ issued to Rochester Gas and Electric ~~Corporation~~ to read as follows:

"Ginna LLC"

R.E. Ginna Nuclear Power Plant, LLC

A. This license applies to the R.E. Ginna Nuclear Power Plant, a closed cycle, pressurized, light-water-moderated and cooled reactor, and electric generating equipment (herein referred to as "the facility") which is owned by ~~the Rochester Gas and Electric Corporation~~ (hereinafter "the licensee" or ~~"RG&E"~~). The facility is located on the licensee's site on the south shore of Lake Ontario, Wayne County, New York, about 16 miles east of the City of Rochester and is described in license application Amendment No. 6, "Final Facility Description and Safety Analysis Report," and subsequent amendments thereto, and in the application for power increase notarized February 2, 1971, and Amendment Nos. 1 through 4 thereto (herein collectively referred to as "the application").

Ginna LLC

B. Subject to the conditions and requirements incorporated herein, the Commission hereby licenses ~~RG&E~~:

(1) Pursuant to Section 104b of the Act and 10 CFR Part 50, "Domestic Licensing of Production and Utilization Facilities," to possess, use and operate the facility at the designated location in Wayne County, New York, in accordance with the procedures and limitations set forth in this license;

(2) Pursuant to the Act and 10 CFR Part 70, to receive, possess, and use at any time special nuclear material or reactor fuel, in accordance with the limitations for storage and amounts required for reactor operation as described in the Final Safety Analysis Report, as amended, and Commission Safety Evaluations dated November 15, 1976, October 5, 1984, November 14, 1984, and August 30, 1995.

(a) Pursuant to the Act and 10 CFR Part 70, to receive and store four (4) mixed oxide fuel assemblies in accordance with the licensee's application dated December 14, 1979 (transmitted by letter dated December 20, 1979);

(b) Pursuant to the Act and 10 CFR Part 70, to possess and use four (4) mixed oxide fuel assemblies in accordance with the licensee's application dated December 14, 1979 (transmitted by letter dated December 20, 1979), as supplemented February 20, 1980 and March 5, 1980;

(3) Pursuant to the Act and 10 CFR Parts 30, 40, and 70 to receive, possess, and use at any time any byproduct, source, and special nuclear material as sealed neutron sources for reactor startup, sealed sources for reactor instrumentation and radiation monitoring equipment calibration, and as fission detectors in amounts as required;

(4) Pursuant to the Act and 10 CFR Parts 30, 40, and 70, to receive, possess, and use in amounts as required any byproduct, source, or special nuclear material without restriction to chemical or physical form, for sample analysis or instrument calibration or associated with radioactive apparatus or components; and

(5) Pursuant to the Act and 10 CFR Parts 30 and 70, to possess, but not separate, such byproduct and special nuclear materials as may be produced by the operation of the facility.

C. This license shall be deemed to contain and is subject to the conditions specified in the following Commission regulations in 10 CFR Part 20, Section 30.34 of Part 30, Section 40.41 of Part 40, Sections 50.54 and 50.59 of Part 50, and Section 70.32 of Part 70; and is subject to all applicable provisions of the Act and rules, regulations and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified below:

(1) Maximum Power Level

Ginna LLC ~~RG&E~~ is authorized to operate the facility at steady-state power levels up to a maximum of 1520 megawatts (thermal).

(2) Technical Specifications

The Technical Specifications contained in Appendix A, as revised through Amendment No. 83, are hereby incorporated in the license. The licensee shall operate the facility in accordance with the Technical Specifications.

(3) Fire Protection

(a) The licensee shall implement and maintain in effect all fire protection features described in the licensee's submittals referenced in and as approved or modified by the NRC's Fire Protection Safety Evaluation (SE) dated February 14, 1979 and SE supplements dated December 17, 1980, February 6, 1981, June 22, 1981, February 27, 1985 and March 21, 1985 or configurations subsequently approved by the NRC, subject to provision (b) below.

(b) The licensee may make changes to the approved fire protection program without prior approval of the Commission only if those changes would not adversely affect the ability to achieve and maintain safe shutdown in the event of a fire.

(c) Deleted

(4) DELETED

(5) DELETED

(6) DELETED

D. The facility requires an exemption from certain requirements of 10 CFR 50.46(a)(1). This includes an exemption from 50.46(a)(1), that emergency core cooling system (ECCS) performance be calculated in accordance with an acceptable calculational model which conforms to the provisions in Appendix K (SER dated April 18, 1978). The exemption will expire upon receipt and approval of revised ECCS calculations. The aforementioned exemption is authorized by law and will not endanger life property or the common defense and security and is otherwise in the public interest. Therefore, the exemption is hereby granted pursuant to 10 CFR 50.12.

E. The licensee shall fully implement and maintain in effect all provisions of the Commission-approved physical security, guard training and qualification, and safeguards contingency plans including amendments made pursuant to provisions of the Miscellaneous Amendments and Search Requirements revisions to 10 CFR 73.55 (51 FR 27827 and 27822) and to the authority of 10 CFR 50.90 and 10 CFR 50.54(p). The plans, which contain Safeguards Information protected under 10 CFR 73.21, are entitled: "Robert Emmet Ginna Nuclear Plant Physical Security Plan," with revisions submitted through August 18, 1987; "Robert Emmet Ginna Nuclear Plant Guard Training and Qualification Plan" with revisions submitted through July 30, 1981; and "Robert Emmet Ginna Nuclear Plant Safeguards Contingency Plan" with revisions submitted through April 14, 1981. Changes made in accordance with 10 CFR 73.55 shall be implemented in accordance with the schedule set forth therein.

F. This license is effective as of the date of issuance and shall expire at midnight, September 18, 2009.

FOR THE NUCLEAR REGULATORY COMMISSION

~~Original signed by~~

~~Darrell G. Eisenhut, Director~~
~~Division of Licensing~~

Attachment:
Appendix A – Technical Specifications

Date of Issuance: ~~December 10, 1984~~

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, DC 20555

R.E. GINNA NUCLEAR POWER PLANT, LLC

DOCKET NO. 50-244

R.E. GINNA NUCLEAR POWER PLANT

FACILITY OPERATING LICENSE

License No. DPR-18

1. The Nuclear Regulatory Commission (the Commission) has found that:

   A. The application complies with the requirements of the Atomic Energy Act of 1954, as amended (the Act), and the regulations of the Commission set forth in 10 CFR Chapter I and all required notifications to other agencies or bodies have been duly made;

   B. Construction of the R.E. Ginna Nuclear Power Plant (the facility) has been substantially completed in conformity with Construction Permit No. CPPR-19, as amended, and the application, the provisions of the Act, and the rules and regulations of the Commission;

   C. The facility will operate in conformity with the application, the provisions of the Act, and the rules and regulations of the Commission;

   D. There is reasonable assurance (i) that the facility can be operated at power levels up to 1520 megawatts (thermal) without endangering the health and safety of the public; and (ii) that such activities will be conducted in compliance with the regulations of the Commission (except as exempted from compliance in Section 2.D below);

   E. The applicant is technically and financially qualified to engaged in the activities authorized by this operating license in accordance with the rules and regulations of the Commission;

   F. The applicant has furnished proof of financial protection that satisfies the requirements of 10 CFR Part 140; and

   G. The issuance of this license will not be inimical to the common defense and security or to the health and safety of the public.

2. The Provisional Operating License dated September 19, 1969, is superseded by Facility Operating License No. DPR-18 originally issued to Rochester Gas and Electric

Corporation and subsequently transferred to R.E. Ginna Nuclear Power Plant, LLC to read as follows:

A. This license applies to the R.E. Ginna Nuclear Power Plant, a closed cycle, pressurized, light-water-moderated and cooled reactor, and electric generating equipment (herein referred to as "the facility") which is owned by R.E. Ginna Nuclear Power Plant, LLC (hereinafter "the licensee" or "Ginna LLC"). The facility is located on the licensee's site on the south shore of Lake Ontario, Wayne County, New York, about 16 miles east of the City of Rochester and is described in license application Amendment No. 6, "Final Facility Description and Safety Analysis Report," and subsequent amendments thereto, and in the application for power increase notarized February 2, 1971, and Amendment Nos. 1 through 4 thereto (herein collectively referred to as "the application").

B. Subject to the conditions and requirements incorporated herein, the Commission hereby licenses Ginna LLC:

(1) Pursuant to Section 104b of the Act and 10 CFR Part 50, "Domestic Licensing of Production and Utilization Facilities," to possess, use and operate the facility at the designated location in Wayne County, New York, in accordance with the procedures and limitations set forth in this license;

(2) Pursuant to the Act and 10 CFR Part 70, to receive, possess, and use at any time special nuclear material or reactor fuel, in accordance with the limitations for storage and amounts required for reactor operation as described in the Final Safety Analysis Report, as amended, and Commission Safety Evaluations dated November 15, 1976, October 5, 1984, November 14, 1984, and August 30, 1995.

(a) Pursuant to the Act and 10 CFR Part 70, to receive and store four (4) mixed oxide fuel assemblies in accordance with the licensee's application dated December 14, 1979 (transmitted by letter dated December 20, 1979);

(b) Pursuant to the Act and 10 CFR Part 70, to possess and use four (4) mixed oxide fuel assemblies in accordance with the licensee's application dated December 14, 1979 (transmitted by letter dated December 20, 1979), as supplemented February 20, 1980 and March 5, 1980;

(3) Pursuant to the Act and 10 CFR Parts 30, 40, and 70 to receive, possess, and use at any time any byproduct, source, and special nuclear material as sealed neutron sources for reactor startup, sealed sources for reactor instrumentation and radiation monitoring equipment calibration, and as fission detectors in amounts as required;

(4) Pursuant to the Act and 10 CFR Parts 30, 40, and 70, to receive, possess, and use in amounts as required any byproduct, source, or special nuclear material without restriction to chemical or physical form, for sample analysis or instrument calibration or associated with radioactive apparatus or components; and

(5) Pursuant to the Act and 10 CFR Parts 30 and 70, to possess, but not separate, such byproduct and special nuclear materials as may be produced by the operation of the facility.

C. This license shall be deemed to contain and is subject to the conditions specified in the following Commission regulations in 10 CFR Part 20, Section 30.34 of Part 30, Section 40.41 of Part 40, Sections 50.54 and 50.59 of Part 50, and Section 70.32 of Part 70; and is subject to all applicable provisions of the Act and rules, regulations and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified below:

(1) Maximum Power Level

Ginna LLC is authorized to operate the facility at steady-state power levels up to a maximum of 1520 megawatts (thermal).

(2) Technical Specifications

The Technical Specifications contained in Appendix A, as revised through Amendment No. 83, are hereby incorporated in the license. The licensee shall operate the facility in accordance with the Technical Specifications.

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(a) The licensee shall implement and maintain in effect all fire protection features described in the licensee's submittals referenced in and as approved or modified by the NRC's Fire Protection Safety Evaluation (SE) dated February 14, 1979 and SE supplements dated December 17, 1980, February 6, 1981, June 22, 1981, February 27, 1985 and March 21, 1985 or configurations subsequently approved by the NRC, subject to provision (b) below.

(b) The licensee may make changes to the approved fire protection program without prior approval of the Commission only if those changes would not adversely affect the ability to achieve and maintain safe shutdown in the event of a fire.

(c) Deleted

(4) DELETED

(5) DELETED

(6) DELETED

D. The facility requires an exemption from certain requirements of 10 CFR 50.46(a)(1). This includes an exemption from 50.46(a)(1), that emergency core cooling system (ECCS) performance be calculated in accordance with an acceptable calculational model which conforms to the provisions in Appendix K (SER dated April 18, 1978). The exemption will expire upon receipt and approval of revised ECCS calculations. The aforementioned exemption is authorized by law and will not endanger life property or the common defense and security and is otherwise in the public interest. Therefore, the exemption is hereby granted pursuant to 10 CFR 50.12.

E. The licensee shall fully implement and maintain in effect all provisions of the Commission-approved physical security, guard training and qualification, and safeguards contingency plans including amendments made pursuant to provisions of the Miscellaneous Amendments and Search Requirements revisions to 10 CFR 73.55 (51 FR 27827 and 27822) and to the authority of 10 CFR 50.90 and 10 CFR 50.54(p). The plans, which contain Safeguards Information protected under 10 CFR 73.21, are entitled: "Robert Emmet Ginna Nuclear Plant Physical Security Plan," with revisions submitted through August 18, 1987; "Robert Emmet Ginna Nuclear Plant Guard Training and Qualification Plan" with revisions submitted through July 30, 1981; and "Robert Emmet Ginna Nuclear Plant Safeguards Contingency Plan" with revisions submitted through April 14, 1981. Changes made in accordance with 10 CFR 73.55 shall be implemented in accordance with the schedule set forth therein.

F. This license is effective as of the date of issuance and shall expire at midnight, September 18, 2009.

FOR THE NUCLEAR REGULATORY COMMISSION

Attachment:
Appendix A – Technical Specifications

Date of Issuance:

Exhibit 2

R. E. GINNA NUCLEAR POWER PLANT

ASSET PURCHASE AGREEMENT

BY AND AMONG

ROCHESTER GAS AND ELECTRIC CORPORATION, AS SELLER

CONSTELLATION GENERATION GROUP, LLC, AS BUYER

AND

CONSTELLATION ENERGY GROUP, INC., AS BUYER'S PARENT

DATED AS OF NOVEMBER 24, 2003

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4.20	General Tax Matters
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ASSET PURCHASE AGREEMENT

ASSET PURCHASE AGREEMENT, dated as of November 24, 2003, (the "Agreement") by and among Rochester Gas and Electric Corporation, a New York corporation ("RG&E" or "Seller"), Constellation Generation Group, LLC, a limited liability company formed under the laws of the state of Maryland ("Buyer"), and Constellation Energy Group, Inc., a Maryland corporation as parent of the Buyer ("Buyer's Parent"). Seller, Buyer and Buyer's Parent are referred to individually as a "Party," and collectively as the "Parties."

WITNESSETH:

WHEREAS, Seller owns R. E. Ginna Nuclear Power Plant ("Ginna"), NRC Operating License No. DPR-18, located in Ontario, New York, and certain facilities and other assets associated therewith and ancillary thereto;

WHEREAS, Buyer desires to purchase and assume, and Seller desires to sell and assign the Purchased Assets (as defined in Section 2.1 below) and certain associated liabilities, upon the terms and conditions hereinafter set forth in this Agreement; and

WHEREAS, the Parties desire that Buyer's Parent support the obligations of Buyer hereunder from the time of execution of this Agreement to the Closing Date.

NOW, THEREFORE, in consideration of the mutual covenants, representations, warranties and agreements hereinafter set forth, and intending to be legally bound hereby, the Parties agree as follows:

ARTICLE 1

DEFINITIONS

Section 1.1 Definitions. As used in this Agreement, the following terms have the meanings specified in this Section 1.1.

(1) "Actual Amount" has the meaning set forth in Section 6.10(h).

(2) "Affiliate" has the meaning set forth in Rule 12b-2 of the General Rules and Regulations under the Exchange Act.

(3) "Agreement" means this Asset Purchase Agreement together with the Schedules and Exhibits hereto, as the same may be from time to time amended.

(4) "Allocation" has the meaning set forth in Section 3.4(b).

(5) "Ancillary Agreements" means the Bill of Sale, Assignment and Assumption Agreement, the Deed, the Easement Agreement, the Interconnection Agreement, the Emergency and Environmental Equipment Easements, the Seller

Parent Guaranty, and the Power Purchase Agreement, as the same may be amended from time to time.

(6) "ANI" means American Nuclear Insurers, or any successor thereto.

(7) "Assignment and Assumption Agreement" means the Assignment and Assumption Agreement between Seller and Buyer substantially in the form of Exhibit "A" hereto, by which Seller, subject to the terms and conditions hereof, shall assign Seller's interest in and rights under the Seller's Agreements, the Fuel Contracts, the Non-material Contracts, the Real Property Agreements, the Transferable Permits, certain intangible assets and other Purchased Assets to Buyer and whereby Buyer shall assume the Assumed Liabilities and Obligations.

(8) "Assumed Liabilities and Obligations" has the meaning set forth in Section 2.3.

(9) "Atomic Energy Act" means the Atomic Energy Act of 1954, as amended, 42 U.S.C. Section 2011 et seq.

(10) "Benefit Plans" has the meaning set forth in Section 4.12(a).

(11) "Bill of Sale" means the Bill of Sale, substantially in the form of Exhibit "B" hereto, to be delivered at the Closing, with respect to Seller's interests in the Tangible Personal Property included in the Purchased Assets to be transferred to Buyer at the Closing.

(12) "Business Books and Records" has the meaning set forth in Section 2.1(g).

(13) "Business Day" shall mean any day other than Saturday, Sunday and any day on which banking institutions in the State of New York are authorized by law or other governmental action to close.

(14) "Buyer" has the meaning set forth in the preamble.

(15) "Buyer Indemnitee" has the meaning set forth in Section 8.1(b).

(16) "Buyer Material Adverse Effect" has the meaning set forth in Section 5.3(a).

(17) "Buyer's Parent" has the meaning set forth in the preamble.

(18) "Buyer's Parent Guaranty" shall mean a guaranty executed by the Buyer's Parent sufficient to satisfy the regulations of the NRC, found at 10 C.F.R. Part 30, Appendix A, regarding guarantees of nuclear decommissioning obligations.

(19) "Buyer's Required Regulatory Approvals" has the meaning set forth in Section 5.3(b).

(20) "Byproduct Material" means any radioactive material (except Special Nuclear Material) yielded in, or made radioactive by, exposure to the radiation incident to the process of producing or utilizing Special Nuclear Material.

(21) "Capital Budget" means the budget established for capital projects for the Purchased Assets as set forth in Schedule 6.1(a), as such budget may be amended by agreement of the Parties.

(22) "Capital Expenditures" has the meaning set forth in Section 3.3(a)(iv).

(23) "Closing" has the meaning set forth in Section 3.1.

(24) "Closing Adjustment" has the meaning set forth in Section 3.3(b).

(25) "Closing Date" has the meaning set forth in Section 3.1.

(26) "COBRA" means the Consolidated Omnibus Budget Reconciliation Act of 1985, as amended, and the rules and regulations promulgated thereunder.

(27) "Code" means the Internal Revenue Code of 1986, as amended.

(28) "Commercially Reasonable Efforts" means efforts which are designed to enable a Party, directly or indirectly, to expeditiously satisfy a condition to, or otherwise assist in the consummation of, the transactions contemplated by this Agreement and which do not require the performing Party to expend any funds or assume Liabilities other than expenditures and Liability assumptions which are customary and reasonable in nature and amount in the context of the transactions contemplated by this Agreement.

(29) "Confidentiality Agreement" means the letter agreement, dated July 8, 2003, between Seller and Buyer's Parent.

(30) "Cooling Tunnel Easement" means the Indenture between The People of the State of New York and Seller dated September 12, 1974 and recorded in the Wayne County Clerk's Office at Liber 677, Page 317.

(31) "Cooling Tunnel Easement Amendment" has the meaning set forth in Section 6.1(a)(7).

(32) "Decommission" or "Decommissioning" means to completely retire and remove the Facilities from service and to restore the Site, as well as any planning and administrative activities incidental thereto, including but not limited to (a) the dismantlement, decontamination and/or storage of the Facilities, in whole or in part, and any reduction or removal of radioactivity at the Site to a level that permits termination of the NRC License, (b) all other activities necessary for the retirement, dismantlement, decontamination and/or storage of the Facilities to comply with all applicable Nuclear Laws and Environmental Laws, including the applicable requirements of the Atomic Energy Act and the NRC's rules, regulations, orders and

pronouncements thereunder, the NRC License for the Facilities and any related decommissioning or license termination plan, and (c) once the Site is no longer utilized either for power generation of any kind or for any storage of Spent Nuclear Fuel or High Level Waste, restoration of the Site to an appropriately graded and vegetated condition, including, but not limited to, the replacement of locally-indigenous trees, plants, shrubs, and grasses to conform substantially with the surrounding environs, as appropriate for the intended use of the Site and the property located thereon. Site restoration shall include, as appropriate, removal and disposal of components and materials meeting NRC release criteria, demolition and removal of decontaminated structures to an approximate depth of three feet below grade, and backfilling of the Site with clean material, grading and landscaping. The Parties understand and agree that SAFSTOR is a permissible method of decommissioning, provided that decommissioning is completed in accordance with the applicable NRC regulations.

(33) "Decommissioning Funds" means the Qualified Decommissioning Funds and the Nonqualified Decommissioning Funds.

(34) "Decommissioning Target" means an amount in dollars equal to (x) \$179,900,000 times (y) 1.0002085 raised to the power of number "Z", where "Z" represents the actual number of days that have elapsed since December 31, 2002 until the Closing Date.

(35) "Deed" has the meaning set forth in Section 3.6(d).

(36) "Department of Energy" or "DOE" means the United States Department of Energy and any successor agency thereto.

(37) "Department of Energy Decommissioning and Decontamination Fees" means all fees related to the Department of Energy's Special Assessment of utilities for the Uranium Enrichment Decontamination and Decommissioning Funds pursuant to Sections 1801, 1802 and 1803 of the Atomic Energy Act and the Department of Energy's implementing regulations at 10 C.F.R. Part 766, applicable to separative work units purchased from the Department of Energy in order to decontaminate and decommission the Department of Energy's gaseous diffusion enrichment facilities.

(38) "Department of Justice" means the United States Department of Justice and any successor agency thereto.

(39) "Direct Claim" has the meaning set forth in Section 8.2(c).

(40) "DOE Credit Support" shall mean (a) the Seller's Parent Guaranty, (b) an irrevocable and unconditional standby letter of credit by a banking or other financial institution that is reasonably acceptable to Buyer, for the benefit of the Buyer, having a drawing amount which is equal to the One-Time DOE Pre-1983 Fee, and payable at the offices of a bank reasonably acceptable to the Buyer, or (c) such

other means of providing assurance of payment of the One-Time DOE Pre-1983 Fee agreeable to Buyer, in Buyer's reasonable discretion.

(41) "DOE Litigation" shall have the meaning set forth in Section 6.13(b).

(42) "Easement Agreement" means the Reciprocal Easement Agreement between Seller and Buyer in substantially the form of Exhibit "C".

(43) "Easements" means, with respect to the Purchased Assets, the easements, licenses and access rights to be granted by the appropriate party by or pursuant to the Interconnection Agreement, the Deed, the Emergency and Environmental Equipment Easements or the Easement Agreement, including, without limitation, easements authorizing access, use, maintenance, construction, repair, replacement and other activities by the parties thereto.

(44) "Emergency and Environmental Equipment Easements" means the easements, leases or other occupancy agreements between Seller and Buyer, each substantially in the form of Exhibit "J" or of Seller's standard form of pole attachment agreement, with respect to each siren, environmental air sampler or environmental or post-accident thermoluminescent dosimeter (a) constituting part of the Purchased Assets, (b) located on property owned or co-owned by Seller immediately after the Closing Date and (c) not located on land that is subject to the Easement Agreement, which Emergency and Environmental Equipment Easements shall be granted by Seller without any rent charge unless such charge is required by Law.

(45) "Emission Reduction Credits" means credits, in units that are established by an applicable Governmental Authority with jurisdiction over the Purchased Assets, resulting from the reduction in the emissions or air pollutants from an emitting source or facility, whether obtained prior to or after the Closing Date, and other air emissions reduction credits whether or not such credits are designated as "emission reduction credits."

(46) "Encumbrances" means any mortgages, pledges, liens, security interests, conditional and installment sale agreements, activity and use limitations, conservation easements, deed restrictions, easements, encumbrances and charges of any kind.

(47) "Energy Reorganization Act" means the Energy Reorganization Act of 1974, as amended.

(48) "Environment" means all soil, real property, air, water (including surface waters, streams, ponds, drainage basins and wetlands), groundwater, water body sediments, drinking water supply, stream sediments or land, including land surface or subsurface strata, including all fish, plant, wildlife, and other biota and any other environmental medium or natural resource.

(49) "Environmental Claim" means any and all written claims alleging potential Liability, administrative or judicial actions, suits, orders, liens, notices

alleging Liability, notices of violation, investigations which have been disclosed in writing to Seller, complaints, requests for information relating to the Release or threatened Release into the Environment of Hazardous Substances, proceedings, or other written communication, whether criminal or civil, pursuant to or relating to any applicable Environmental Law by any Governmental Authority based upon, alleging, asserting, or claiming any actual or potential (a) violation of, or Liability under any Environmental Law, (b) violation of any Environmental Permit, or (c) Liability for investigatory costs, cleanup costs, removal costs, remedial costs, response costs, natural resource damages, property damage, personal injury, fines, or penalties arising out of, based on, resulting from, or related to the presence, Release, or threatened Release into the Environment of any Hazardous Substances at any location related to the Purchased Assets, including, but not limited to, any off-Site location to which Hazardous Substances, or materials containing Hazardous Substances, were sent.

(50) "Environmental Clean-up Site" means any location which is listed or formally proposed for listing on the National Priorities List, the Comprehensive Environmental Response, Compensation and Liability Information System, or on any similar state list of sites requiring investigation or cleanup, or which is the subject of any action, suit, proceeding or investigation which has been disclosed in writing to Seller for any alleged violation of any Environmental Law, or at which there has been a Release, or, to the Knowledge of Seller, a threatened or suspected Release, of a Hazardous Substance.

(51) "Environmental Condition" means the presence or Release to the Environment, whether at the Site or at an off-Site location, of Hazardous Substances, including any migration of those Hazardous Substances through air, soil or groundwater to or from the Site or any off-Site location regardless of when such presence or Release occurred or is discovered.

(52) "Environmental Laws" means all Laws regarding pollution or protection of the Environment, the conservation and management of land, natural resources and wildlife or human health and safety or the Occupational Safety and Health Act (only as it relates to Hazardous Substances), including, without limitation, Laws regarding Releases or threatened Releases of Hazardous Substances (including, without limitation, Releases to ambient air, surface water, groundwater, land, surface and subsurface strata) or otherwise relating to the manufacture, processing, distribution, use, treatment, storage, Release, transport, disposal or handling of Hazardous Substances. "Environmental Laws" include, without limitation, the Comprehensive Environmental Response, Compensation, and Liability Act (42 U.S.C. §§ 9601 et seq.), the Hazardous Materials Transportation Act (49 U.S.C. §§ 1801 et seq.), the Resource Conservation and Recovery Act (42 U.S.C. §§ 6901 et seq.), the Federal Water Pollution Control Act (33 U.S.C. §§ 1251 et seq.), the Clean Air Act (42 U.S.C. §§ 7401 et seq.), the Toxic Substances Control Act (15 U.S.C. §§ 2601 et seq.), the Oil Pollution Act (33 U.S.C. §§ 2701 et seq.), the Emergency Planning and Community Right-to-Know Act (42 U.S.C. §§ 11001 et seq.), the Occupational Safety and Health Act (29 U.S.C. §§ 651 et seq.) only as it relates to

Hazardous Substances, Articles 17, 19, 24, 27 (Titles 9, 11 and 13), 29, 37 and 40 of the New York Environmental Conservation Law and all other Laws analogous to any of the above. Notwithstanding the foregoing, Environmental Laws do not include Nuclear Laws.

(53) "Environmental Permit" means any federal, state or local permits, licenses, approvals, consents, registrations or authorizations required by any Governmental Authority under or in connection with any Environmental Law including any and all orders, consent orders or binding agreements issued or entered into by a Governmental Authority under any applicable Environmental Law.

(54) "ERISA" means the Employee Retirement Income Security Act of 1974, as amended, and the applicable rules and regulations promulgated thereunder.

(55) "ERISA Affiliate" has the meaning set forth in Section 2.4(k).

(56) "Estimated Adjustment" has the meaning set forth in Section 3.3(b).

(57) "Estimated Allocation" has the meaning set forth in Section 3.4(a).

(58) "Estimated Closing Statement" has the meaning set forth in Section 3.3(b).

(59) "Excess Decommissioning Funds" means the estimated cost savings to Buyer as a result of not completing any Decommissioning activities necessary or appropriate to restore the Site to an appropriately graded and vegetated condition as appropriate for the intended use of the Site and the property located thereon. For purposes of this definition, the Excess Decommissioning Funds will be calculated by Buyer in good faith and subject to concurrence by the NYPSC.

(60) "Exchange Act" means the Securities Exchange Act of 1934, as amended.

(61) "Excluded Assets" has the meaning set forth in Section 2.2.

(62) "Excluded Liabilities" has the meaning set forth in Section 2.4.

(63) "Exempt Wholesale Generator" means an exempt wholesale generator as defined in Section 32 of the Holding Company Act and the regulations promulgated thereunder.

(64) "Facilities" means the plant, facilities, equipment, supplies and improvements, including, but not limited to, the cooling water intake tunnel and discharge canal, in which Seller has an ownership interest and which are included in the Purchased Assets, constituting the nuclear power plant known as the R.E. Ginna Nuclear Power Plant.

(65) "Federal Power Act" means the Federal Power Act, as amended.

(66) "Federal Trade Commission" means the United States Federal Trade Commission or any successor agency thereto.

(67) "FERC" means the United States Federal Energy Regulatory Commission or any successor agency thereto.

(68) "Final Safety Analysis Report" or "FSAR" means the report, as updated, that is required to be maintained for Ginna in accordance with the requirements of 10 C.F.R. § 50.71(e).

(69) "Fuel Contracts" has the meaning set forth in Section 4.15(a)

(70) "Ginna" has the meaning set forth in the recitals.

(71) "Ginna Employee" means an hourly-paid or salaried employee of Seller or an Affiliate, who receives an Internal Revenue Service Form W-2 from Seller or an Affiliate, employed as of the Closing Date who is employed at Ginna, or whose work responsibilities involve principally the operation of any of the Purchased Assets, which employees shall be set forth in Schedule 6.10(a) (which shall be updated as of the Closing Date as provided for herein). "Ginna Employee" does not mean or include any worker, working at or on the Facilities or the Purchased Assets, who is compensated directly by an entity other than Seller or an Affiliate and/or for whom Seller or an Affiliate issues an Internal Revenue Service Form 1099.

(72) "Good Utility Practices" means any of the practices, methods and activities generally accepted in the electric utility industry in the United States of America as good practices applicable to nuclear generating facilities of similar design, size and capacity and consistent with past practice at the Facilities or any of the practices, methods or activities which, in the exercise of reasonable judgment by a prudent nuclear operator in light of the facts known at the time the decision was made (other than the fact that such operator is in the process of selling the facility), could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety, expedition and applicable Laws including Nuclear Laws and Laws relating to the protection of public health and safety. Good Utility Practices are not intended to be limited to the optimal practices, methods or acts to the exclusion of all others, but rather to be practices, methods or acts generally accepted in the electric utility industry.

(73) "Governmental Authority" means any federal, state, local, provincial, foreign, international or other governmental, regulatory or administrative agency, taxing authority, commission, department, board, or other governmental subdivision, court, tribunal, arbitrating body or other governmental authority.

(74) "GUST" means: (a) the Uruguay Round Agreements Act, Pub. L. 103-465; (b) the Uniformed Services Employment and Reemployment Rights Act of 1994, Pub. L. 103-353; (c) the Small Business Job Protection Act of 1996, Pub. L. 104-188; (d) the Taxpayer Relief Act of 1997, Pub. L. 105-34; (e) the Internal

Revenue Service Restructuring and Reform Act of 1998, Pub. L. 105-206; and (f) the Community Renewal Tax Relief Act of 2000, Pub. L. 106-554.

(75) "Hazardous Substances" means (a) any petroleum, asbestos, and urea formaldehyde foam insulation and transformers or other equipment that contains polychlorinated biphenyls; (b) any chemicals, materials or substances defined as or included in the definition of "hazardous substances," "hazardous wastes," "hazardous materials," "hazardous constituents," "restricted hazardous materials," "extremely hazardous substances," "toxic substances," "contaminants," "pollutants," "toxic pollutants," "hazardous air pollutants" or words of similar meaning and regulatory effect under any applicable Environmental Law; and (c) any other chemical, material or substance, exposure to which is prohibited, limited or regulated by any applicable Environmental Law; excluding, however, any Nuclear Material.

(76) "High Level Waste" means (a) Spent Nuclear Fuel, (b) liquid wastes resulting from the operation of the first cycle solvent extraction system, or its equivalent, and the concentrated wastes from subsequent extraction cycles, or their equivalent, in a facility for reprocessing irradiated reactor fuel, (c) solids into which such liquid wastes have been converted, and (d) any other material containing radionuclides in concentrations or quantities that exceed NRC requirements for classification as Low Level Waste.

(77) "High Level Waste Repository" means a facility which is designed, constructed and operated by or on behalf of the Department of Energy for the storage and disposal of Spent Nuclear Fuel and other High Level Waste in accordance with the requirements set forth in the Nuclear Waste Policy Act.

(78) "Holding Company Act" means the Public Utility Holding Company Act of 1935, as amended.

(79) "HSR Act" means the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended.

(80) "Income Tax" means any federal, state, local or foreign Tax (a) based upon, measured by or calculated with respect to net income, profits or receipts (including, without limitation, capital gains Taxes and minimum Taxes), or (b) based upon, measured by or calculated with respect to multiple bases (including, without limitation, corporate franchise taxes) if one or more of the bases on which such Tax may be based, measured by or calculated with respect to, is described in clause (a), in each case together with any interest, penalties or additions to such Tax.

(81) "Indemnifiable Loss" has the meaning set forth in Section 8.1(a).

(82) "Indemnifying Party" has the meaning set forth in Section 8.1(c).

(83) "Indemnitee" means either a Seller Indemnitee or a Buyer Indemnitee.

(84) "Independent Accounting Firm" means such independent accounting firm of national reputation as is mutually appointed by Seller and Buyer.

(85) "Initial Transfer" has the meaning set forth in Section 6.10(h).

(86) "Intellectual Property" means all patents and patent rights, trademarks and trademark rights, service marks and service mark rights, inventions, trade names, copyrights and copyright rights owned or licensed by Seller and necessary for the operation and maintenance of the Purchased Assets, and all pending applications for registrations of patents, trademarks, service marks and copyrights, as set forth in Schedule 2.1(j).

(87) "Interconnection Agreement" means the Interconnection Agreement, in the form of Exhibit "D" hereto, under which Ginna will be provided after the Closing Date with interconnection services consistent with FERC regulations and precedent and NRC requirements relating to offsite power availability and grid reliability and access to Seller's transmission facilities for the transmission of power from Ginna.

(88) "Inventory of Major Spare Parts" means the spare reactor coolant pump motor, spare low pressure turbine rotor, spare main transformer and their respective replacements, if any.

(89) "Inventories" means Nuclear Fuel or alternative fuel inventories, materials, spare parts (including Inventory of Major Spare Parts), consumable supplies and chemical and gas inventories relating to the operation of the Facilities located at, or in transit to, the Facilities and the interests of the Seller in spare parts located off-Site which are subject to the PIMS Agreement.

(90) "IRS" means the United States Internal Revenue Service or any successor agency thereto.

(91) "Knowledge" means the actual knowledge of the corporate officers of the specified Party charged with responsibility for the particular function relating to the specific matter of the inquiry.

(92) "LAR" has the meaning set forth in Section 6.21(a).

(93) "Law or Laws" means all laws, rules, regulations, codes, statutes, ordinances, decrees, treaties, and/or administrative orders of any Governmental Authority.

(94) "Liability" or "Liabilities" means any liability or obligation (whether known or unknown, whether asserted or unasserted, whether absolute or contingent, whether accrued or unaccrued, whether liquidated or unliquidated, whether incurred or consequential and whether due or to become due). Without limiting the generality of the foregoing, in the case of the NRC License, "Liabilities" shall include the NRC Commitments.

(95) "License Renewal Application" means the application submitted by Seller to the NRC, as amended and supplemented, seeking renewal of the NRC License.

(96) "Loss" or "Losses" means any and all damages, fines, fees, penalties, deficiencies, losses and expenses (including without limitation all Remediation costs, fees of attorneys, accountants and other experts, or other expenses of litigation or proceedings or of any claim, default or assessment).

(97) "Low Level Waste" means radioactive material that: (a) is neither High Level Waste as defined herein, nor byproduct material (as defined in Section 11e.(2) of the Atomic Energy Act (42 U.S.C. 2014(e)(2)); and (b) the NRC, consistent with existing law and in accordance with clause (a), classifies as low-level radioactive waste. For the purposes of the Purchase Price adjustment in Section 3.3(a)(vi) only, the term "Low Level Waste" shall not include the items which are set forth in Schedule 3.3(a)(vi) as being excluded from the definition of "Low Level Waste" for purposes of that Purchase Price adjustment.

(98) "Material Adverse Effect" means any change (or changes taken together) in, or effect on, the Purchased Assets (including the operations or condition (financial or otherwise) thereof) that is materially adverse to the value of the Purchased Assets, taken as a whole, including but not limited to, those that result in (i) shutdown of the Facilities, (ii) a material diminution of the full licensed thermal power or the full rated electrical output of the Facilities, or (iii) any loss, claim or occurrence related to the Purchased Assets which could reasonably be expected to cause a loss and/or the expenditure by the Buyer within one year following the Closing Date in excess of Two and One-Half Million Dollars ($2,500,000) individually, or in excess of Twenty Five Million Dollars ($25,000,000) in the aggregate, other than any change (or changes taken together) generally affecting the international, national, regional or local electric industry as a whole, or the nuclear power industry as a whole, including changes in local wholesale or retail markets for electric power or Nuclear Fuel, national, regional or local electric transmission systems or operations thereof, any change in law generally applicable to similarly situated Persons, any changes resulting from or associated with acts of war or terrorism or changes imposed by a Governmental Authority associated with additional security to address the events of September 11, 2001 and any change or effect resulting from action or inaction by a Governmental Authority with respect to an independent system operator or retail access in New York, but in any such case not affecting the Purchased Assets or the Parties in any manner or degree significantly different than the industry as a whole; and provided further, that any loss, claim, occurrence, change or effect that is cured prior to the Closing Date shall not be considered a Material Adverse Effect.

(99) "Mortgage Indenture" means the Indenture of Mortgage originally granted by Rochester Railway and Light Company to Bankers Trust Company (now Deutsche Bank Trust Company), as Trustee, dated as of September 1, 1918, as supplemented and amended.

(100) "NEIL" means Nuclear Electric Insurance Limited, or any successor thereto.

(101) "Non-material Contracts" means those contracts, agreements, personal property leases or other commitments incidental to the operation or maintenance of the Purchased Assets that have been entered into by Seller in the ordinary course of business prior to the Closing which either (i) are terminable, without penalty or any other termination related Liability, upon notice of 90 days or less by Seller or (ii) require the payment or delivery of goods or services with a value of less than $50,000 per annum in the case of any individual contract or commitment.

(102) "Nonqualified Decommissioning Funds" means the external trust fund that does not meet the requirements of Code Section 468A and Treas. Reg. § 1.468A-5, maintained by Seller with respect to the Facilities prior to the Closing pursuant to the Seller's Decommissioning Trust Agreement, and established and maintained by the Trustee after the Closing pursuant to the Post-Closing Decommissioning Trust Agreement to the extent assets are transferred to such trust pursuant to Section 6.12.

(103) "NRC" means the United States Nuclear Regulatory Commission and any successor agency thereto.

(104) "NRC Commitments" means all written regulatory commitments identified as such by Seller to the NRC, including, without limitation, all written regulatory commitments identified as such by Seller in connection with its License Renewal Application.

(105) "NRC License" means Operating License No. DPR-18 and any renewed license related thereto on the basis of which the Seller is authorized to own, possess and operate the Facilities and Nuclear Material prior to the Closing Date, and on the basis of which the Buyer is authorized to own, possess and operate the Facilities and Nuclear Material after the Closing Date.

(106) "Nuclear Fuel" means all nuclear fuel assemblies in the Facility reactor on the Closing Date and any irradiated fuel assemblies that have been temporarily removed from the Facilities reactor as of the Closing Date and are capable of reinsertion into the Facilities reactor without modification or additional cost, and all unirradiated fuel assemblies awaiting insertion into the Facilities reactor, as well as all nuclear fuel constituents (including uranium in any form and separative work units) in any stage of the fuel cycle that are in process of production, conversion, enrichment or fabrication for use in the Facilities and which are owned by Seller, or in which Seller has any right, title or interest, on the Closing Date.

(107) "Nuclear Insurance Policies" means all nuclear insurance policies carried by or for the benefit of Seller with respect to the ownership, operation or maintenance of the Facilities, including all nuclear liability, property damage and business interruption policies in respect thereof. Without limiting the generality of the

foregoing, the term "Nuclear Insurance Policies" includes all policies issued or administered by ANI or NEIL.

(108) "Nuclear Laws" means all Laws relating to the regulation of nuclear power plants, Source Material, Byproduct Material and Special Nuclear Materials; the regulation of Low Level Waste and High Level Waste; the transportation and storage of Nuclear Materials; the regulation of Safeguards Information; the regulation of Nuclear Fuel; the enrichment of uranium; the disposal and storage of High Level Waste and Spent Nuclear Fuel; contracts for and payments into the Nuclear Waste Fund; and as applicable, the antitrust laws and the Federal Trade Commission Act to specified activities or proposed activities of certain licensees of commercial nuclear reactors, but shall not include Environmental Laws. "Nuclear Laws" include the Atomic Energy Act of 1954, as amended (42 U.S.C. Section 2011 et seq.), the Price-Anderson Act (Section 170 of the Atomic Energy Act of 1954, as amended); the Energy Reorganization Act of 1974 (42 U.S.C. Section 5801 et seq.); Convention on the Physical Protection of Nuclear Material Implementation Act of 1982 (Public Law 97 -351; 96 Stat. 1663); the Foreign Assistance Act of 1961 (22 U.S.C. Section 2429 et seq.); the Nuclear Non-Proliferation Act of 1978 (22 U.S.C. Section 3201); the Low-Level Radioactive Waste Policy Act (42 U.S.C. Section 2021b et seq.); the Nuclear Waste Policy Act (42 U.S.C. Section 10101 *et seq.* as amended); the Low-Level Radioactive Waste Policy Amendments Act of 1985 (42 U.S.C. Section 2021d, 471); and the Energy Policy Act of 1992 (4 U.S.C. Section 13201 et seq.); and any state or local Laws analogous to the foregoing.

(109) "Nuclear Material or Materials" means Source Material, Special Nuclear Material, Low Level Waste, High Level Waste, Byproduct Material and Spent Nuclear Fuel.

(110) "Nuclear Waste Fund" means the fund established by the Department of Energy under the Nuclear Waste Policy Act in which the Spent Nuclear Fuel Fees to be used for the design, construction and operation of a High Level Waste Repository and other activities related to the storage and disposal of Spent Nuclear Fuel and/or High Level Waste are deposited.

(111) "Nuclear Waste Policy Act" means the Nuclear Waste Policy Act of 1982, as amended.

(112) "NYDEC" means the New York State Department of Environmental Conservation and any successor agency thereto.

(113) "NYPSC" means the Public Service Commission of the State of New York and any successor agency thereto.

(114) "Observers" has the meaning set forth in Section 6.1(c).

(115) "One-Time DOE Pre-1983 Fee" means the one-time fee, including any interest, late fees and/or penalties accruing thereon from time to time, payable by

Seller pursuant to Article VIII (B)(2)(b) of the Standard Spent Fuel Disposal Contract.

(116) "Other Plant Personnel" has the meaning set forth in Section 4.11.

(117) "Party" (and the corresponding term "Parties") has the meaning set forth in the preamble.

(118) "PBGC" means the Pension Benefit Guaranty Corporation established by ERISA.

(119) "Permits" has the meaning set forth in Section 4.17(a).

(120) "Permitted Encumbrances" means: (i) the Easements; (ii) those exceptions to title to the Purchased Assets listed in Schedule 4.7 with respect to Real Property; (iii) with respect to any date before the Closing Date, Encumbrances created by the Mortgage Indenture; (iv) statutory liens for Taxes or other governmental charges or assessments not yet due or delinquent or the validity of which are being contested in good faith by appropriate proceedings provided that the aggregate amount being so contested does not exceed $200,000; (v) mechanics', materialmen's, carriers', workers', repairers' and other similar liens arising or incurred in the ordinary course of business relating to obligations as to which there is no default on the part of Seller or the validity of which are being contested in good faith, and which do not, individually or in the aggregate, exceed $200,000; (vi) zoning, entitlement, conservation restriction and other land use and environmental regulations imposed by Governmental Authorities which do not materially, individually or in the aggregate, detract from the value of the Purchased Assets as such assets are currently used or interfere with the present use or operation of the Purchased Assets and neither secure indebtedness, nor, individually or in the aggregate, result in a Material Adverse Effect; (vii) the covenants and restrictions set forth in this Agreement or in any of the Ancillary Agreements; and (viii) such other liens, imperfections in or failures of title, easements, leases, licenses, restrictions, activity and use limitations, conservation easements, encumbrances and encroachments, as do not, individually or in the aggregate, materially detract from the value of the Purchased Assets as such assets are currently used or materially interfere with the present use or operation of the Purchased Assets and neither secure indebtedness, nor, individually or in the aggregate, result in a Material Adverse Effect.

(121) "Person" means any individual, partnership, limited liability company, joint venture, corporation, trust, unincorporated organization, association, or governmental entity or any political subdivision, department or agency thereof.

(122) "PIMS Agreement" means the agreement between Seller and Pooled Equipment Inventory Company, effective July 1, 2002, as amended, with respect to pooled inventory management.

(123) "Plans" has the meaning set forth in Section 2.4(k).

(124) "Post-Closing Adjustment" has the meaning set forth in Section 3.3(c).

(125) "Post-Closing Decommissioning Trust Agreement" means the decommissioning trust agreement between Buyer and the Trustee pursuant to which any assets of any of the Decommissioning Funds to be transferred by Seller at Closing pursuant to Section 6.12 hereof will be held in trust.

(126) "Post-Closing Statement" has the meaning set forth in Section 3.3(c).

(127) "Power Purchase Agreement" means the Power Purchase Agreement between Seller and Buyer, dated as of the date of this Agreement and in the form of Exhibit "F" hereto.

(128) "Price-Anderson Act" means Section 170 of the Atomic Energy Act and related provisions of Section 11 of the Atomic Energy Act.

(129) "Proposed Post-Closing Adjustment" has the meaning set forth in Section 3.3(c).

(130) "Proprietary Information" means (i) with respect to information provided by Seller to Buyer, has the meaning as set forth in the Confidentiality Agreement, and (ii) with respect to information provided by Buyer to Seller, shall mean information relating to the financing or operation and maintenance, actual or proposed, of the Purchased Assets and any financial, operational or other information concerning Buyer or its Affiliates or their respective assets and properties furnished by Buyer or its Representatives to Seller or its Representatives, whether furnished before or after the date hereof, whether oral or written, and regardless of the manner in which it is furnished; but does not include information which (a) is or becomes generally available to the public other than as a result of a disclosure by Seller or its Representatives, (b) was available to Seller or its Representatives on a non-confidential basis prior to its disclosure by Buyer or its Representatives or (c) becomes available on a non-confidential basis from a person other than Buyer or its Representatives who is not otherwise bound by a confidentiality agreement with Buyer or its Representatives, or is otherwise not under any obligation to Buyer or its Representatives not to transmit the information to Seller or its Representatives.

(131) "Purchased Assets" has the meaning set forth in Section 2.1.

(132) "Purchase Price" has the meaning set forth in Section 3.2.

(133) "Qualified Decommissioning Funds" means the external trust funds that meet the requirements of Code Section 468A and Treas. Reg. § 1.468A-5, maintained by Seller with respect to the Facilities prior to Closing pursuant to Seller's Decommissioning Trust Agreement and maintained by Buyer after the Closing pursuant to the Post-Closing Decommissioning Trust Agreement to the extent assets are transferred to such fund by Seller pursuant to Section 6.12.

(134) "Real Property" has the meaning set forth in Section 2.1(a).

(135) "Real Property Agreements" has the meaning set forth in Section 4.8.

(136) "Release" means any spilling, leaking, pumping, pouring, emitting, emptying, discharging, injecting, escaping, leaching, dumping or disposing of a Hazardous Substance into the Environment or within any building, structure, facility or fixture.

(137) "Remediation" means action of any kind required by any applicable Law or order of a Governmental Authority to address a Release, the threat of a Release or the presence of Hazardous Substances at the Site or an off-Site location including, without limitation, any or all of the following activities to the extent they relate to or arise from the presence of a Hazardous Substance at the Site or an off-Site location: (a) monitoring, investigation, assessment, treatment, cleanup, containment, removal, mitigation, response or restoration work; (b) obtaining any permits, consents, approvals or authorizations of any Governmental Authority necessary to conduct any such activity; (c) preparing and implementing any plans or studies for any such activity; (d) obtaining a written notice from a Governmental Authority with jurisdiction over the Site or an off-Site location under Environmental Laws that no material additional work is required by such Governmental Authority; (e) the use, implementation, application, installation, operation or maintenance of remedial action on the Site or an off-Site location, remedial technologies applied to the surface or subsurface soils, excavation and off-Site treatment or disposal of soils, systems for long term treatment of surface water or ground water, engineering controls or institutional controls; and (f) any other activities required under Environmental Laws to address the presence or Release of Hazardous Substances at the Site or an off-Site location.

(138) "Replacement Benefit Plan" has the meaning set forth in Section 6.10(e).

(139) "Replacement Defined Benefit Plan" has the meaning set forth in Section 6.10(h).

(140) "Replacement Retiree Coverages" has the meaning set forth in Section 6.10(m).

(141) "Replacement Welfare Plans" has the meaning set forth in Section 6.10(d).

(142) "Representatives" of a Party means the Party and its Affiliates and their directors, officers, employees, agents, partners, advisors (including, without limitation, accountants, counsel, environmental consultants, financial advisors and other authorized representatives) and parents and other controlling Persons.

(143) "Requested Rulings" has the meaning set forth in Section 6.18.

(144) "RG&E" has the meaning set forth in the preamble.

(145) "RG&E Defined Benefit Plan" has the meaning set forth in Section 6.10(h).

(146) "RG&E Retiree Coverages" has the meaning set forth in Section 6.10(m).

(147) "RG&E Savings Plan" has the meaning set forth in Section 6.10(g).

(148) "Safeguards Information" means information not otherwise classified as national security information or restricted data under NRC's regulations which specifically identifies an NRC licensee's detailed (1) security measures for the physical protection of Special Nuclear Material, or (2) security measures for the physical protection and location of certain plant equipment vital to the safety of production or utilization facilities.

(149) "SEC" means the United States Securities and Exchange Commission and any successor agency thereto.

(150) "Securities Act" means the Securities Act of 1933, as amended.

(151) "Seller" has the meaning set forth in the preamble.

(152) "Seller Indemnitee" has the meaning set forth in Section 8.1(a).

(153) "Seller's Agreements" means those contracts, agreements, licenses and leases relating to the ownership, operation and maintenance of the Purchased Assets, as more particularly described on Schedule 4.15(a)(i), as such schedule is supplemented and amended in accordance with the provisions of this Agreement.

(154) "Seller's Decommissioning Trust Agreement" means the Master Decommissioning Trust Agreement, made as of March 9, 1990, as amended, between RG&E and Mellon Bank, N.A., regarding the Qualified Decommissioning Fund and the Nonqualified Decommissioning Fund of Seller.

(155) "Seller's Parent" shall mean Energy East Corporation.

(156) "Seller's Parent Guaranty" means the Guaranty executed by Seller's Parent, dated the Closing Date and in the form attached hereto as Exhibit "G".

(157) "Seller's Required Regulatory Approvals" has the meaning set forth in Section 4.3(b).

(158) "Site" means the parcels of land included in the Real Property. Any reference to the Site shall include, by definition, the surface and subsurface elements, including the soils and groundwater present at the Site and any references to items "at

the Site" shall include all items "at, in, on, upon, over, across, under, and within" the Site.

(159) "Source Material" means: (1) uranium or thorium; or any combination thereof, in any physical or chemical form, or (2) ores which contain by weight one-twentieth of one percent (0.05%) or more of (i) uranium, (ii) thorium, or (iii) any combination thereof. Source Material does not include Special Nuclear Material.

(160) "Special Nuclear Material" means plutonium, uranium enriched in the isotope-233 or in the isotope-235, and any other material that the NRC determines to be "Special Nuclear Material," but does not include Source Material. Special Nuclear Material also refers to any material artificially enriched by any of the above-listed materials or isotopes, but does not include Source Material.

(161) "Spent Nuclear Fuel" means fuel that has been permanently withdrawn from a nuclear reactor following irradiation, and has not been chemically separated into its constituent elements by reprocessing. Spent Nuclear Fuel includes the Special Nuclear Material, Byproduct Material, Source Material greater than Class C waste, and other radioactive materials associated with Nuclear Fuel assemblies.

(162) "Spent Nuclear Fuel Fees" means those fees assessed on electricity generated at Ginna and sold pursuant to the Standard Spent Fuel Disposal Contract, as provided in Section 302 of the Nuclear Waste Policy Act and 10 C.F.R. Part 961, as the same may be amended from time to time, including, but not limited to, the One-Time DOE Pre-1983 Fee.

(163) "Standard Spent Fuel Disposal Contract" means the Contract for Disposal of Spent Nuclear Fuel and/or High Level Radioactive Waste, No. DE-CR01-83NE44419, dated June 30, 1983, entered into between RG&E and the United States of America, represented by the Department of Energy, as amended.

(164) "Subsidiary" when used in reference to any Person means any entity of which outstanding securities having ordinary voting power to elect a majority of the Board of Directors or other Persons performing similar functions of such entity, are owned directly or indirectly, by such Person.

(165) "Tangible Personal Property" has the meaning set forth in Section 2.1(c).

(166) "Tax Basis" means the adjusted tax basis determined for federal income tax purposes under Code Section 1011(a).

(167) "Tax" or "Taxes" means, all taxes, charges, fees, levies, penalties or other assessments imposed by any federal, state or local or foreign taxing authority, including but not limited to, income, excise, real or personal property, sales, transfer, franchise, payroll, withholding, social security, receipts, license, stamp, occupation, employment or other taxes, including any interest, penalties or additions attributable

thereto, and any payments to any state, local or foreign taxing authorities in lieu of any such taxes, charges, fees, levies or assessments.

(168) "Tax Return" means any return, report, information return, declaration, claim for refund or other document (including any schedule or related or supporting information) required to be supplied to any taxing authority with respect to Taxes including amendments thereto.

(169) "Termination Date" has the meaning set forth in Section 9.1(b).

(170) "Third Party Claim" has the meaning set forth in Section 8.2(a).

(171) "Title Company" has the meaning set forth in Section 7.1(j).

(172) "Total Compensation" has the meaning set forth in Section 6.10(c).

(173) "Transferable Permits" means those Permits and Environmental Permits identified in Schedule 1.1(173), which are transferable to Buyer without application to, a filing with, notice to, consent or approval of any Governmental Authority.

(174) "Transferred Employee Records" means all records related to Transferred Employees, including but not limited to the following information: (i) skill and development training, (ii) seniority histories, (iii) salary and benefit information, (iv) Occupational, Safety and Health Administration reports, (v) active medical restriction forms, (vi) fitness for duty, (vii) disciplinary actions, (viii) job performance appraisals and/or evaluations, (ix) employment applications, (x) bonuses, (xi) job history, (xii) access authorization records, and (xiii) radiation exposure records.

(175) "Transferred Employees" has the meaning set forth in Section 6.10(b).

(176) "Transfer Taxes" means all state or local real property transfer, sales, use, value added, stamp, recording, registration, conveyance and other like Taxes and other fees, including without limitation any payments made in lieu of such Taxes which become payable in connection with the transactions contemplated by this Agreement.

(177) "Transition Committee" has the meaning set forth in Section 6.1(b).

(178) "Transmission Assets" has the meaning set forth in Section 2.2(a).

(179) "Trustee" means with respect to Seller prior to the Closing the trustee of the Decommissioning Funds appointed by Seller pursuant to Seller's Decommissioning Trust Agreement and after the Closing to the extent any assets of the Decommissioning Funds are transferred by Seller pursuant to Section 6.12 hereof, the trustees appointed pursuant to the Post-Closing Decommissioning Trust Agreement.

(180) "Uprate" has the meaning set forth in Section 6.21(a).

(181) "Uprate Reports" has the meaning set forth in Section 6.21(a).

(182) "USEPA" means the United States Environmental Protection Agency and any successor agency thereto.

(183) "WARN Act" means the Worker Adjustment and Retraining Notification Act of 1988, as amended.

(184) "WARN Certificate" has the meaning set forth in Section 6.10(i).

Section 1.2 Certain Interpretive Matters. In this Agreement, unless the context otherwise requires, the singular shall include the plural, the masculine shall include the feminine and neuter, and vice versa. The term "includes" or "including" shall mean "including without limitation." References to a Section, Article, Exhibit or Schedule shall mean a Section, Article, Exhibit or Schedule of this Agreement, and reference to a given agreement or instrument shall be a reference to that agreement or instrument as modified, amended, supplemented and restated through the date as of which such reference is made.

ARTICLE 2

PURCHASE AND SALE

Section 2.1 Purchased Assets. Upon the terms and subject to the satisfaction of the conditions contained in this Agreement, at the Closing, Seller will sell, assign, convey, transfer and deliver to Buyer, and Buyer will purchase, assume and acquire from Seller, free and clear of all Encumbrances (except for Permitted Encumbrances), all of Seller's right, title and interest in and to the following assets, wherever located (collectively, the "Purchased Assets"): (i) all of the assets used in, held for use, constituting, or necessary in the ordinary course of business to operate and maintain Ginna (but excluding such assets that are not necessary for the operation of Ginna as a generating station and are used predominantly elsewhere in the operation of Seller's business), including, without limitation, those assets identified in Schedule 2.1(j) and Schedules 4.13(a) and (b), and (ii) those assets described below (but excluding the Excluded Assets):

(a) Except as otherwise constituting part of the Excluded Assets, the land described on Schedule 4.13(a) (which land comprises the Site) together with all buildings, facilities and other improvements thereon including the Facilities (but excluding any personal property thereon) and all appurtenances thereto, including, without limitation, all related rights of ingress and egress (collectively, the "Real Property");

(b) All Nuclear Materials and Inventories owned by Seller, or in which the Seller has any right, title or interest, on the Closing Date, wherever located;

(c) All machinery, mobile or otherwise, equipment (including computer hardware and software and transferable rights thereto and communications equipment), vehicles, tools, spare parts, materials, works in progress, fixtures, furniture and furnishings and other personal property relating to or used in the ordinary course of business to operate and maintain the Facilities, including, without limitation, the items of personal property included in Schedule 4.13(b), other than property used primarily as part of the Transmission Assets or otherwise constituting part of the Excluded Assets (collectively, "Tangible Personal Property");

(d) Subject to the provisions of Sections 2.1(p) and 6.4(d), all rights of Seller under the Fuel Contracts, Non-material Contracts and the Seller's Agreements which have not been identified in Schedule 2.2(l) as Excluded Assets;

(e) All Real Property Agreements;

(f) All Transferable Permits;

(g) To the extent permitted by Law, all books, operating records, licensing records, quality assurance records, purchasing records, and equipment repair, maintenance or service records of Seller relating to the design, construction, licensing or operation of the Facilities, operating, safety and maintenance manuals, inspection reports, environmental assessments, engineering design plans, documents, blueprints and as built plans, specifications, procedures and other similar items of Seller, wherever located, relating to the Facilities and the other Purchased Assets, whether existing in hard copy or magnetic or electronic form (subject to the right of Seller to retain copies of same for its use) (collectively, the "Business Books and Records");

(h) All unexpired, transferable warranties and guarantees from third parties with respect to any item of Real Property or Tangible Personal Property constituting part of the Purchased Assets;

(i) The name "R. E. Ginna" or "Ginna" as used as a designation attached to or associated with the Facilities and any related logos;

(j) The Intellectual Property described on Schedule 2.1(j);

(k) The substation equipment, if any, designated in the Interconnection Agreement or the Easement Agreement as being transferred to Buyer;

(l) The assets comprising that portion of the Decommissioning Funds that is transferred to Buyer pursuant to Section 6.12 of this Agreement, together with all related tax accounting and other records for such assets, including all decommissioning studies, analyses and cost estimates;

(m) To the extent transferable, all Nuclear Insurance Policies with ANI, including all rights to collect premium refunds made after the Closing Date, including, but not limited to, those pursuant to the ANI nuclear industry credit rating plan (other than refunds that relate to premiums paid for time periods prior to the Closing Date);

(n) Subject to the receipt of approval from the Wireless Bureau of the Federal Communications Commission, certain radio licenses set forth on Schedule 2.1(n);

(o) Subject to Buyer's written commitment to satisfy its indemnification obligations under Section 8.1(a), the right to proceeds from insurance policies for coverage of Assumed Liabilities and Obligations;

(p) Subject to Buyer's written commitment to satisfy its indemnification obligations under Section 8.1(a), the rights of Seller in and to any causes of action, claims and defenses against third parties (including indemnification and contribution) relating to any Assumed Liabilities and Obligations, including, but not limited to, all rights of Seller in and to any cause of action or claim pending or hereafter initiated with respect to damages incurred prior to, on or after the Closing Date relating to the DOE Litigation; provided that the prosecution of any cause of action or claim related to the DOE Litigation shall be conducted as specified in Section 6.13 and any recovery of damages, costs, attorneys' fees, interest and penalties, or any other expenses awarded shall be shared between Seller and Buyer in accordance with Section 6.13;

(q) The Transferred Employee Records, subject to the right of Seller to retain copies of such records for its reasonable and lawful use and subject to the obligation of Buyer to preserve such records and make such records available to Seller as reasonably necessary for Seller's reasonable and lawful purposes following the Closing Date as provided in Section 6.2(c);

(r) Any rights of Seller with respect to prior assessments of licensees of operating nuclear power plants to support disposal facility development activities by the NYDEC, and the former Commission for Siting Low-Level Radioactive Waste Disposal Facilities, which ceased operation in August 1995;

(s) All assignable right, title and interest of the Seller to the NRC License;

(t) All rights of the Seller in property, assets, leases and agreements used or usable in providing emergency warning or associated with emergency preparedness as set forth on Schedule 2.1(t);

(u) All Emission Reduction Credits or emission allowances that relate to the operation of the Facilities prior to, on or after the Closing Date; and

(v) The assets required to be transferred from the RG&E Defined Benefit Plan to the Replacement Defined Benefit Plan or paid from Seller to Buyer as set forth in Section 6.10(h).

Section 2.2 Excluded Assets. Notwithstanding anything to the contrary in this Agreement, nothing in this Agreement shall be construed as conferring on Buyer, and Buyer is not acquiring, any right, title or interest in or to the following specific assets which are associated with the Purchased Assets, but which are hereby specifically excluded from the sale and the definition of Purchased Assets herein (the "Excluded Assets"):

(a) Except as expressly identified in Schedule 4.13(b) or the Interconnection Agreement or the Easement Agreement, the electrical transmission or distribution facilities (as opposed to generation facilities) of Seller or any of its Affiliates, as well as all permits, contracts and warranties, to the extent they relate to such transmission and distribution assets (collectively, the "Transmission Assets"), and those assets and facilities identified on Schedule 2.2(a);

(b) Certificates of deposit, shares of stock, securities, bonds, debentures, evidences of indebtedness, and interests in joint ventures, partnerships, limited liability companies and other entities (including, without limitation, Seller's member account balances with NEIL), except such assets comprising the portion of the Decommissioning Funds which is required to be transferred to the Buyer pursuant to Section 6.12 hereof and except such assets required to be transferred from the RG&E Defined Benefit Plan to the Replacement Defined Benefit Plan or paid from Seller to Buyer as set forth in Section 6.10(h);

(c) All rights to collect premium refunds and distributions made after the Closing Date under Nuclear Insurance Policies to the extent that such refunds and distributions relate to premiums paid prior to the Closing Date;

(d) All cash, cash equivalents, bank deposits, accounts and notes receivable (trade or otherwise), and any income, sales, payroll or other tax receivables, except to the extent such assets are included in the portion of the Decommissioning Funds transferred to Buyer pursuant to Section 6.12 hereof and except such assets required to be transferred from the RG&E Defined Benefit Plan to the Replacement Defined Benefit Plan or paid from Seller to Buyer as set forth in Section 6.10(h);

(e) The rights of Seller and its Affiliates to the names "Rochester Gas and Electric Corporation" and "RG&E" or any related or similar trade names, trademarks, service marks, corporate names or logos, or any part, derivative or combination thereof;

(f) All tariffs, agreements and arrangements to which Seller is a party for the purchase or sale of electric capacity and/or energy or for the purchase or sale of transmission or ancillary services;

(g) Other than those contemplated by Section 2.1(p), the rights of Seller in and to any causes of action, claims and defenses against third parties (including indemnification and contribution) arising out of or relating to (A) any Real Property or personal property, Permits, Taxes, Real Property Agreements, Seller's Agreements, Fuel Contracts or the Non-material Contracts, if any, including any claims for refunds (including refunds of previously paid Department of Energy Decommissioning and Decontamination Fees), prepayments, offsets, recoupment, insurance proceeds, condemnation awards, judgments and the like, whether received as payment or credit against future liabilities, relating specifically to the Purchased Assets (including, without limitation, the Facilities and the Site) and relating to any period prior to the Closing Date, (B) the Excluded Assets, or (C) the Excluded Liabilities;

(h) All personnel records of Seller and Affiliates, except the Transferred Employee Records;

(i) Any and all of Seller's rights in any contract representing an intercompany transaction between Seller and an Affiliate of Seller, whether or not such transaction relates to the provision of goods and services, payment arrangements, intercompany charges or balances, or the like;

(j) To the extent not otherwise provided for in this Section 2.2, any refund or credit (i) related to income, real or personal property, excise, sales or use Taxes paid by Seller with respect to periods (or portions thereof) prior to the Closing Date in respect of the Purchased Assets, whether such refund is received as a payment or as a credit against future income, real or personal property, excise, sales or use Taxes payable, or (ii) arising under any agreement which is part of the Purchased Assets and relating to a period prior to the Closing Date;

(k) Any cause of action or claim for damages or other rights that relate to the One-Time DOE Pre-1983 Fee; and

(l) All rights of Seller under those contracts, agreements, purchase orders and personal property leases set forth in Schedule 2.2(l).

Section 2.3 Assumed Liabilities and Obligations. On the Closing Date, Buyer shall deliver to Seller the Assignment and Assumption Agreement pursuant to which Buyer shall assume and agree to discharge when due, all of the following Liabilities of Seller (collectively, "Assumed Liabilities and Obligations"):

(a) All Liabilities of Seller arising on or after the Closing Date with respect to the ownership, operation or maintenance of the Purchased Assets, and all Liabilities of Seller arising on or after the Closing Date under Seller's Agreements, the Standard Spent Fuel Disposal Contract, Fuel Contracts, the Real Property Agreements, the Non-material Contracts and the Transferable Permits in accordance with the terms thereof, including, without limitation, (i) the contracts, licenses, agreements and personal property leases entered into by Seller with respect to the Purchased Assets or under Seller's Agreements or the Fuel Contracts or the Non-material Contracts and disclosed on the relevant schedule and (ii) the contracts, licenses, agreements and personal property leases entered into by Seller with respect to the Purchased Assets after the date hereof consistent with the terms of this Agreement, except in each case to the extent such Liabilities, but for a breach or default by Seller or a related waiver or extension, would have been paid, performed or otherwise discharged on or prior to the Closing Date or to the extent the same arise out of any such breach or default or out of any event which after the giving of notice or the passage of time would constitute a default by Seller

(b) All Liabilities or obligations with respect to the Transferred Employees relating to personal injury, discrimination, wrongful discharge, unfair labor practice, or constructive termination of any individual, or similar claim or cause of action attributable to any actions or inactions on or after the Closing Date;

(c) All Liabilities (except for Excluded Liabilities) of Seller under or related to Environmental Laws, whether past, current or future, or the common law, with respect to the Site; provided however, that Buyer does not assume any Liability for the off-Site disposal or Release of Hazardous Substances or the arrangement for such activities prior to the Closing Date, as provided in Section 2.4(f) hereof, except that for the purposes of Section 2.3 and 2.4 "off-Site" does not include any location adjoining the Site to which Hazardous Substances Released at the Site have migrated;

(d) All Liabilities of Seller associated with or arising from the Purchased Assets in respect of Taxes for which Buyer is liable pursuant to Sections 3.5 or 6.8(a) hereof;

(e) All Liabilities with respect to Transferred Employees for which Buyer is responsible pursuant to Section 6.10. Moreover, for employees of the Seller who become Transferred Employees as of the Closing Date or who are listed on Schedule 4.11 (as updated as of the Closing Date to include former employees of the Seller whose work assignments principally involved the operation of any of the Purchased Assets and whose employment has been terminated by Seller between the date hereof and the Closing Date) to the extent required by a court of competent jurisdiction, administrative agency or arbitrator, Buyer shall implement any prospective changes (as opposed to compensatory costs, damages or other Liabilities relating to any periods prior to the Closing) in the terms of the employment of any such employee whose position no longer exists at Seller, whose position exists at Buyer and who is subsequently ordered to be reinstated following the resolution of any claims or causes of action, irrespective of when such claim or cause of action is filed or threatened;

(f) With respect to the Purchased Assets, any Tax that may be imposed by any federal, state or local government on the ownership, sale, operation or use of the Purchased Assets on or after the Closing Date or that relates to or arises from the Purchased Assets with respect to taxable periods (or portions thereof) beginning on or after the Closing Date (except for any Income Taxes attributable to income actually received by Seller);

(g) All Liabilities of Seller to Decommission the Facilities and the Site;

(h) All Liabilities of Seller associated with (i) the Nuclear Fuel consumed, or to be consumed, at Ginna from and after the Closing Date and (ii) the management, storage, removal, transportation and disposal on and after the Closing Date of all Nuclear Materials of Ginna ; provided, however, that Buyer does not assume any Liability for the off-Site disposal of Low Level Waste prior to the Closing Date as required pursuant to Laws in effect as of the Closing Date;

(i) All obligations arising on or after the Closing Date to pay to ANI any additional premiums due to audit assessments for assessments performed on or after the Closing Date;

(j) All Liabilities arising under or relating to Nuclear Laws or relating to any claim in respect of Nuclear Fuel or Nuclear Materials arising out of the ownership or operation of the Purchased Assets on or after the Closing Date, including any and all Liabilities to third parties (including employees) for personal injury, property damage or tort, or similar causes of action arising out of the ownership or operation of the Purchased Assets on or after the Closing Date, including Liabilities arising out of or resulting from a "nuclear incident" or "precautionary evacuation" (as such terms are defined in the Atomic Energy Act) at the Site, or any other licensed nuclear reactor site in the United States, or in the course of the transportation of radioactive materials to or from the Site or any other site on or after the Closing Date, including, without limitation, Liability for any deferred premiums assessed in connection with such a nuclear incident or precautionary evacuation under any applicable NRC or industry retrospective rating plan or insurance policy, including any mutual insurance pools established in compliance with the requirements imposed under Section 170 of the Atomic Energy Act, 10 C.F.R. Part 140, and 10 C.F.R. § 50.54(w);

(k) Any Liability for any Price-Anderson Act secondary financial protection retrospective premium obligations for (i) nuclear worker Liability attributable to employment on or after the Closing Date or (ii) any third-party Liability arising out of any nuclear incident on or after the Closing Date;

(l) Except as otherwise expressly provided herein, Liabilities of Buyer to the extent arising from the execution, delivery or performance of this Agreement and the transactions contemplated hereby; and

(m) All other Liabilities expressly allocated to or assumed by Buyer in this Agreement.

Section 2.4 Excluded Liabilities. Notwithstanding anything to the contrary in this Agreement, nothing in this Agreement shall be construed to impose on Buyer, and Buyer shall not assume or be obligated to pay, perform or otherwise discharge, the following Liabilities (the "Excluded Liabilities"), with all of such Excluded Liabilities remaining as obligations of Seller:

(a) Any Liabilities of Seller in respect of any Excluded Assets or other assets of Seller which are not Purchased Assets;

(b) Any Liabilities in respect of Taxes attributable to the ownership, operation or use of the Purchased Assets for taxable periods, or portions thereof, ending before the Closing Date, except for Taxes for which Buyer is liable pursuant to Sections 3.5 or 6.8(a) hereof;

(c) Any Liabilities of Seller arising under any of Seller's Agreements, Fuel Contracts, Real Property Agreements, Transferable Permits or any of the Non-material Contracts prior to the Closing Date;

(d) Any monetary fines or penalties (including investigatory or similar costs) imposed by a Governmental Authority with respect to the Purchased Assets resulting from (i) an investigation, proceeding, request for information or inspection before or by a Governmental Authority that commenced prior to the Closing Date, or (ii) criminal acts, willful misconduct or gross negligence of Seller;

(e) Subject to Section 3.5, any payment obligations of Seller for goods delivered or services rendered prior to the Closing Date, including, but not limited to, rental or lease payments due and owing prior to the Closing Date pursuant to the Real Property Agreements and any leases relating to Tangible Personal Property;

(f) Any Liability under or related to Environmental Laws or the common law (whether or not arising or made manifest before the Closing Date or on or after the Closing Date), arising as a result of, in connection with or allegedly caused by the disposal, storage, transportation, discharge, Release, or recycling of Hazardous Substances off-Site, or the arrangement for such activities, in connection with the ownership or operation of the Purchased Assets prior to the Closing Date except that for the purpose of Sections 2.3 and 2.4, "off-Site" does not include any location adjoining the Site to which Hazardous Substances disposed of or Released at the Site have migrated;

(g) Third party Liability for any claims arising as a result of or in connection with loss of life or injury to persons or damages to property prior to the Closing Date (whether or not such loss or injury was made manifest on or after the Closing Date) caused (or allegedly caused) by the presence or Release of Hazardous Substances at, on, in, under, adjacent to or migrating from the Purchased Assets prior to the Closing Date; provided Seller will not have any Liability to third parties for any claims arising as a result of or in connection with loss of life or injury to persons or damages to property caused (or allegedly caused) by the Release by Buyer of Hazardous Substances at, on, in, or under, the Purchased Assets on or after the Closing Date;

(h) All Liabilities arising under or relating to Nuclear Laws or relating to any claim in respect of Nuclear Fuel or Nuclear Materials arising out of the ownership or operation of the Purchased Assets prior to the Closing Date (except for

Liabilities associated with the management, storage, removal, transportation and disposal of Nuclear Fuel and Nuclear Material), including any and all Liabilities to third parties (including employees) for personal injury, property damage or tort, or similar causes of action arising out of the ownership or operation of the Purchased Assets prior to the Closing Date, including Liabilities arising out of or resulting from a "nuclear incident" or "precautionary evacuation" (as such terms are defined in the Atomic Energy Act) at the Site, or any other licensed nuclear reactor site in the United States, or in the course of the transportation of radioactive materials to or from the Site or any other site prior to the Closing Date, including, without limitation, Liability for any deferred premiums assessed in connection with such a nuclear incident or precautionary evacuation under any applicable NRC or industry retrospective rating plan or insurance policy, including any mutual insurance pools established in compliance with the requirements imposed under Section 170 of the Atomic Energy Act, 10 C.F.R. Part 140, and 10 C.F.R. § 50.54(w);

(i) Any Liabilities relating to Seller's operations on, or usage of, the Easements, including, without limitation, Liabilities arising as a result of or in connection with (1) any violation or alleged violation of Environmental Law and (2) loss of life, injury to persons or property or damage to natural resources, but only to the extent caused by Seller;

(j) Subject to Section 6.10(h) and 6.10(o), any Liabilities relating to any Benefit Plan, any employee benefit plan as defined in Section 3(3) of ERISA, or any other plan, program, arrangement or policy established or maintained in whole or in part by Seller or by any trade or business (whether or not incorporated) which is or ever has been under common control, or which is or ever has been treated as a single employer, with Seller under Section 414(b), (c), (m) or (o) of the Code ("ERISA Affiliate") or to which Seller or any ERISA Affiliate contributes or contributed, including any multiemployer plan contributed to by Seller or any ERISA Affiliate or to which Seller or any ERISA Affiliate is or was obligated to contribute (the "Plans"), including, but not limited to any such Liability (i) for the termination or discontinuance of, or the Seller's or an ERISA Affiliate's withdrawal from, any such Plan, (ii) relating to benefits payable under any Plans, (iii) relating to the PBGC under Title IV of ERISA, (iv) relating to a multi-employer plan, (v) with respect to noncompliance with the notice requirements of COBRA, (vi) with respect to any noncompliance with ERISA or any other applicable Laws, and (vii) with respect to any suit, proceeding or claim which is brought against Buyer, any Plan or any fiduciary or former fiduciary of, any of the Plans;

(k) Any Liabilities relating to the failure to hire, the employment or services or termination of employment or services of any individual, including wages, compensation, benefits, affirmative action, personal injury, discrimination, harassment, retaliation, constructive termination, wrongful discharge, unfair labor practices, or constructive termination by the Seller of any individual, or any similar or related claim or cause of action attributable to any actions or inactions by Seller prior to the Closing Date with respect to the Purchased Assets, the Transferred Employees, independent contractors, applicants, and any other individuals who are determined by a court or by a Governmental Authority to have been applicants or employees of the Seller or any of its Affiliates (including, but not limited to, any Liability related to the matter disclosed on Schedule 4.11), or that are filed with or pending before any court, administrative agency or arbitrator prior to the Closing Date, including, but not limited to, the claim set forth on Schedule 4.11, provided Seller will not have any Liability for similar actions or inactions by Buyer or any successor thereto on or after the Closing Date;

(l) All Spent Nuclear Fuel Fees and any other fees associated with electricity generated at Ginna and sold on or prior to the Closing Date, including, but not limited to, the obligation to the Department of Energy under the Standard Spent Fuel Disposal Contract to make the deferred payment of the One-Time DOE Pre-1983 Fee;

(m) All Liabilities for Department of Energy Decommissioning and Decontamination Fees;

(n) Any Encumbrances on the Purchased Assets, except for Permitted Encumbrances and except as consented to by Buyer in accordance with Section 6.1;

(o) Except as otherwise expressly provided herein, Liabilities of Seller to the extent arising from the execution, delivery or performance of this Agreement and the transactions contemplated hereby; and

(p) Any other Liabilities expressly allocated to or assumed by Seller in this Agreement.

Section 2.5 Control of Litigation. (a) The Parties agree and acknowledge that, subject to the provisions of Article 8 and Section 6.13, Seller shall pay for and be entitled exclusively to control, defend and settle any litigation, administrative or regulatory proceeding, and any investigation or other activities arising out of or related to any Excluded Liabilities and Buyer agrees to reasonably cooperate, at Seller's expense, with Seller in connection therewith.

(b) The Parties agree and acknowledge that, subject to the provisions of Article 8 and Section 6.13, Buyer shall pay for and be entitled exclusively to control, defend and settle any litigation, administrative or regulatory proceeding, and any investigation or other activities arising out of or related to any Assumed Liabilities and Obligations, and Seller agrees to reasonably cooperate, at Buyer's expense, with Buyer in connection therewith.

ARTICLE 3

THE CLOSING

Section 3.1 Closing. Upon the terms and subject to the satisfaction of the conditions contained in Article 7 of this Agreement, the sale, assignment, conveyance, transfer and delivery of the Purchased Assets to Buyer, the payment of the Purchase Price to Seller, and the consummation of the other respective obligations of the Parties contemplated by this Agreement shall take place at a closing (the "Closing"), to be held at the offices of LeBoeuf, Lamb, Greene & MacRae, L.L.P., 125 West 55th Street, New York, New York 10019, at 10:00 a.m. local time, or another mutually acceptable time and location, on the date that is twenty (20) Business Days following the date on which the last of the conditions precedent to Closing set forth in Article 7 of this Agreement have been either satisfied or waived by the Party for whose benefit such conditions precedent exist, but in any event not after the Termination Date, unless the Parties mutually agree on another date; provided that, in setting the Closing Date, the matters contemplated by Section 7.1 (g), (h), (i), (j), (l), (m), (n), (p) and (q) and Section 7.2 (g), (h), (i), (j) and (k), shall be assumed to have been satisfied; provided, however, that the actual satisfaction of such provisions shall in all cases be considered to be a condition to Closing. The date of Closing is hereinafter called the "Closing Date." The Closing shall be effective for all purposes as of 12:01 a.m. on the Closing Date.

Section 3.2 Payment of Purchase Price. Upon the terms and subject to the satisfaction of the conditions contained in this Agreement, in consideration of the aforesaid sale, assignment, conveyance, transfer and delivery of the Purchased Assets, Buyer will pay or cause to be paid to Seller at the Closing in consideration of the Purchased Assets the sum of Four Hundred and Twenty-Two Million, Six Hundred Thousand Dollars ($422,600,000) ("Purchase Price") plus or minus any adjustments to such Purchase Price pursuant to the provisions of Section 3.3 below, by wire transfer of immediately available funds denominated in U.S. dollars or by such other means as are agreed upon by Seller and Buyer.

Section 3.3 Adjustment to Purchase Price.

(a) Subject to Section 3.3(b) and 3.3(c), at the Closing, the Purchase Price shall be adjusted, without duplication, to account for the items set forth in this Section 3.3(a):

(i) The Purchase Price shall be adjusted to account for the items prorated as of the Closing Date pursuant to Section 3.5.

(ii) The Purchase Price shall be (A) increased if and to the extent that the net book value of that portion of Nuclear Fuel which consists of all nuclear fuel assemblies in the Facilities reactor on the Closing Date and any irradiated fuel assemblies that have been temporarily removed from the Facilities reactor as of the Closing Date and are capable of reinsertion without modification or additional cost is greater than $21,600,000, and (B) decreased if and to the extent the net book value of that portion of Nuclear Fuel which consists of all nuclear fuel assemblies in the Facilities reactor on the Closing Date and any irradiated fuel assemblies that have been temporarily removed from the Facilities reactor as of the Closing Date and are capable of reinsertion without modification or additional cost, is less than $21,600,000 (all calculations are to be consistent with Seller's past practices).

(iii) The Purchase Price shall be (A) increased if and to the extent that the gross book value of the Inventory of Major Spare Parts and the Seller's interest in the Inventory subject to the PIMS Agreement on the Closing Date is greater than $14,000,000, and (B) decreased if and to the extent the gross book value of the Inventory of Major Spare Parts and the Seller's interest in the Inventory subject to the PIMS Agreement on the Closing Date is less than $14,000,000 (all calculations are to be consistent with Seller's past practices).

(iv) The Purchase Price shall be increased by the amount expended by Seller between the date hereof and the Closing Date for capital additions to or replacements of property, plant and equipment included in the Purchased Assets and other expenditures or repairs on property, plant and equipment included in the Purchased Assets that are capitalized by Seller in accordance with its normal accounting policies, provided, that, such expenditures either (1) are described in the Capital Budget, or (2) are necessary to comply with changes in applicable Laws effected after the date of this Agreement, or (3) have been specifically requested or approved by Buyer in writing, or (4) are made in accordance with Good Utility Practices and exceed $3,000,000 in the aggregate (the "Capital Expenditures"). Nothing in this paragraph should be construed to limit Seller's rights and obligations to make all capital expenditures necessary to comply with the NRC License, the NRC Commitments and other Permits.

(v) The Purchase Price shall be adjusted as set forth in Sections 6.10(h) and (k) and Section 6.21(c).

(vi) If the cost to dispose of the Low Level Waste at the Facilities as of the Closing Date is greater than $250,000, based on the disposal criteria set forth in Schedule 3.3(a)(vi), the Purchase Price shall be adjusted downward by every dollar that the cost of such Low Level Waste disposal is greater than $250,000. Conversely, if the cost to dispose of the Low Level Waste at the Facilities as of the Closing Date is less than $250,000, the Purchase Price shall be adjusted upward by every dollar that the cost of such Low Level Waste disposal is less than $250,000.

(vii) The Purchase Price shall be increased for every dollar paid by Seller to a third party for uranium conversion, enrichment or fabrication in connection with Ginna Reload Cycle 32 and/or fuel and fuel design costs required for the Uprate referred to in Section 6.20, including but not limited to, payments made by Seller to third parties with respect to all unirradiated fuel assemblies awaiting insertion into the Facility reactor, as well as all nuclear fuel constituents in any stage of the fuel cycle that are in process of production, conversion, enrichment or fabrication for use in the Facility.

(viii) The Purchase Price shall be adjusted as provided in Schedule 3.3(a)(viii) in the event that the Closing occurs on a date before or after June 30, 2004; provided, however that no such adjustment shall be made, in the event that the Closing occurs after June 30, 2004 as a result of either (i) the failure of Buyer to satisfy its performance obligations under this Agreement or (ii) the failure to receive regulatory approval from the NRC for the transfer of the NRC License to Buyer by June 30, 2004 where there remain unresolved issues in the application related to NRC approval of Buyer's foreign ownership, control or domination, if applicable.

(b) No less than ten (10) Business Days prior to the Closing Date, Seller shall prepare in good faith and deliver to Buyer an estimated closing statement (the "Estimated Closing Statement") that shall set forth Seller's best estimate of all estimated adjustments to the Purchase Price required by Section 3.3(a) (the "Estimated Adjustment"). Within ten (10) days after the delivery of the Estimated Closing Statement by Seller to Buyer, Buyer may object in good faith to the Estimated Adjustment in writing. If Buyer objects to the Estimated Adjustment, the Parties shall attempt to resolve their differences by negotiation. If the Parties are unable to do so prior to the Closing Date (or if Buyer does not object to the Estimated Adjustment), the Purchase Price shall be adjusted (the "Closing Adjustment") for the Closing by the amount of the Estimated Adjustment not in dispute. The disputed portion shall be resolved in accordance with the provisions of Section 3.3(c) and paid as part of any Post-Closing Adjustment to the extent required by Section 3.3(c).

(c) Within sixty (60) days after the Closing Date, Seller shall prepare and deliver to Buyer a final closing statement (the "Post-Closing Statement") that shall set forth all adjustments to the Purchase Price required by Section 3.3(a) (the "Proposed Post-Closing Adjustment") and all work papers detailing such adjustments. The Post-Closing Statement shall be prepared using the same accounting principles, policies and methods as Seller has historically used in connection with the calculation of the items reflected on such Post-Closing Statement. Within thirty (30) days after the delivery of the Post-Closing Statement by Seller to Buyer, Buyer may object to the Proposed Post-Closing Adjustment in writing. Seller agrees to cooperate with Buyer to provide Buyer with the information used to prepare the Post-Closing Statement and information relating thereto. If Buyer objects to the Proposed Post-Closing Adjustment, the Parties shall attempt to resolve such dispute by negotiation. If the Parties are unable to resolve such dispute within thirty (30) days after any objection by Buyer, the Parties shall appoint the Independent Accounting Firm, which shall, at Seller's and Buyer's joint expense, review the Proposed Post-Closing Adjustment and determine the appropriate adjustment to the Purchase Price, if any, within thirty (30) days after such appointment. The Parties agree to cooperate with the Independent Accounting Firm and provide it with such information as it reasonably requests to enable it to make such determination. The finding of such Independent Accounting Firm shall be binding on the Parties hereto. Upon determination of the appropriate adjustment (the "Post-Closing Adjustment") by agreement of the Parties or by binding determination of the Independent Accounting Firm, the Party owing the difference shall deliver such amount to the other Party no later than two (2) Business

Days after such determination, in immediately available funds or in any other manner as reasonably requested by the payee.

Section 3.4 Allocation of Purchase Price.

(a) At least twenty (20) Business Days prior to the Closing Date, Buyer shall determine, with the assistance of an independent engineer or appraiser, and provide to Seller an estimated allocation among the Purchased Assets of the sum of the Purchase Price and the Assumed Liabilities and Obligations that is consistent with the allocation methodology provided by Section 1060 and 338 of the Code and the regulations promulgated thereunder (the "Estimated Allocation"). The Estimated Allocation shall be subject to the approval of the Seller, which approval shall not be unreasonably withheld. The Estimated Allocation will be used for transfer tax, bulk sale filings and for all other Closing document purposes.

(b) Within ninety (90) days after the Closing Date, the Buyer shall determine, with the assistance of an independent engineer or appraiser, and provide to Seller the allocation among the Purchased Assets of the sum of the Purchase Price (including any adjustments thereto) and the Assumed Liabilities and Obligations (together with any other relevant items) that is consistent with the allocation methodology provided by Section 1060 and 338 of the Code and the regulations promulgated thereunder (the "Allocation"). The Allocation shall be subject to the approval of the Seller, which approval shall not be unreasonably withheld.

(c) Except to the extent required to comply with audit determinations of any tax authority with jurisdiction over a Party, Buyer and Seller shall report the transactions contemplated by this Agreement for all required federal income Tax and all other Tax purposes in a manner consistent with the Allocation. Buyer and Seller shall not take any position in any Tax Return, Tax proceeding or audit that is inconsistent with the Allocation without the consent of the other Party. To the extent such filings are required, Buyer and Seller agree to file Internal Revenue Service Form 8594 (Asset Acquisition Statement Under Section 1060), and all federal, state, local and foreign Tax Returns, in accordance with the Allocation. Subsequent to the preparation of the Allocation as provided in Sections 3.4(a) and (b), Buyer and Seller agree to provide the other with any information required to complete Form 8594 within ten (10) days of the request for such information. Buyer and Seller shall notify and provide the other with reasonable assistance in the event of an examination, audit or other proceeding regarding the allocation of the Purchase Price pursuant to this Section 3.4. Buyer and Seller shall treat the transaction contemplated by this Agreement as the acquisition by Buyer of a trade or business for United States federal income Tax purposes and agree that no portion of the consideration shall be treated in whole or in part as the payment for services or future services.

Section 3.5 Prorations.

(a) Buyer and Seller agree that all of the items normally prorated, including those listed below (but not including Income Taxes), relating to the business and operation of the Purchased Assets shall be prorated as of the Closing Date, with Seller liable to the extent such items relate to any time period prior to the Closing Date, and Buyer liable to the extent such items relate to periods commencing with the Closing Date (measured in the same units used to compute the item in question, otherwise measured by calendar days):

(i) Personal property, real estate, occupancy and water Taxes, assessments and other charges, if any, on or with respect to the business and operation of the Purchased Assets;

(ii) Any prepaid expenses (including security deposits) relating to the Purchased Assets;

(iii) Rent, Taxes and all other items (including prepaid services or goods not included in Inventory) payable by or to Seller under any of Seller's Agreements or the Non-material Contracts;

(iv) Any permit, license, registration, compliance assurance fees or other fees with respect to any Transferable Permit;

(v) Sewer rents and charges for water, telephone, electricity and other utilities; and

(vi) Rent and Taxes and other items payable by Seller under the Real Property Agreements assigned to Buyer.

(b) In connection with the prorations referred to in (a) above, in the event that actual figures are not available at the Closing Date, the proration shall be based upon the actual Taxes or other amounts accrued through the Closing Date or paid for the most recent year (or other appropriate period) for which actual Taxes or other amounts paid are available. Such prorated Taxes or other amounts shall be re-prorated and paid to the appropriate Party within sixty (60) days of the date that the previously unavailable actual figures become available. Prorations measured by calendar days shall be based on the number of days in a year or other appropriate period (i) before the Closing Date and (ii) including and after the Closing Date. Seller and Buyer agree to furnish each other with such documents and other records as may be reasonably requested in order to confirm all adjustment and proration calculations made pursuant to this Section 3.5.

Section 3.6 Deliveries by Seller. At the Closing (or, in the case of those items contemplated by paragraph (j) below, at the Facilities on or before the Closing Date), Seller will deliver, or cause to be delivered, the following to Buyer:

(a) The Bill of Sale, duly executed by Seller;

(b) Copies of any and all governmental and other third party consents, waivers or approvals obtained by Seller with respect to the transfer of the Purchased Assets, or the consummation of the transactions contemplated by this Agreement;

(c) The opinions of counsel and officer's certificates of Seller contemplated by Sections 7.1(g) and (h);

(d) Bargain and sale deed with covenant provided for by Section 13 of the Lien Law of the State of New York, conveying the Real Property to Buyer, in substantially the form of Exhibit "E" hereto, duly executed and acknowledged by Seller in recordable form (the "Deed"), and any owner's affidavits or similar documents reasonably required by the title company;

(e) All Ancillary Agreements duly executed by Seller (and with respect to any Ancillary Agreement consisting of a pole attachment agreement, if necessary, by any co-owner of the pole), as applicable;

(f) Copies, certified by the Secretary or Assistant Secretary of Seller, of corporate resolutions authorizing the execution and delivery of this Agreement and all of the agreements and instruments to be executed and delivered by Seller in connection herewith, and the consummation of the transactions contemplated hereby;

(g) A certificate of the Secretary or Assistant Secretary of Seller identifying the name and title and bearing the signatures of the officers of Seller authorized to execute and deliver this Agreement and the other agreements and instruments contemplated hereby;

(h) Certificate of good standing with respect to Seller, issued by the Secretary of the State of New York;

(i) To the extent available, Tax clearance certificates or Tax status certificates dated no more than thirty (30) days prior to the Closing for each jurisdiction identified on Schedule 4.20;

(j) To the extent available, originals of the Seller's Agreements, Fuel Contracts, Non-material Contracts, Real Property Agreements, Transferred Employee Records and Transferable Permits and, if not available, true and correct copies thereof, in all cases together with notices to and, if required by the terms thereof, consents by other Persons which are parties to the Seller's Agreements, Fuel Contracts, Non-material Contracts, Real Property Agreements and Transferable Permits;

(k) The assets of the Decommissioning Funds to be transferred pursuant to Section 6.12 shall be delivered to the Trustee of the Post-Closing Decommissioning Trust Agreement;

(l) All such other instruments of assignment, transfer or conveyance as shall, in the reasonable opinion of Buyer and its counsel, be necessary or desirable to transfer to Buyer the Purchased Assets, in accordance with this Agreement and where necessary or desirable in recordable form;

(m) The WARN Certificate;

(n) An ALTA-ACSM survey certified by the surveyor to Buyer and the Title Company, which survey shall have been updated to a date within thirty (30) days before the Closing and shall mention and show (if of a kind that can reasonably be expected to be shown) all title exceptions included in the then most recent title commitment provided to Seller by Buyer;

(o) The written consent of the Office of General Services of the State of New York to the assignment by Seller to Buyer of the Cooling Tunnel Easement which consent shall be in recordable form, and shall not materially alter the terms of said Cooling Tunnel Easement to Buyer's detriment;

(p) A letter executed by Geomatrix reasonably satisfactory in form and substance to Buyer allowing Buyer to rely on the Phase I and Phase II report as to the Site, the Phase I report as to the Station 13A Parcel (as defined in the Easement Agreement), and the other environmental assessments (and all amendments thereto) issued by Geomatrix on or after January 1, 2003 with respect to the Site; and

(q) Such other agreements, consents, documents, instruments and writings as are required to be delivered by Seller at or prior to the Closing Date pursuant to this Agreement or the Ancillary Agreements or otherwise reasonably required in connection herewith.

Section 3.7 Deliveries by Buyer. At the Closing, Buyer will deliver, or cause to be delivered, the following to Seller:

(a) The Purchase Price, payable pursuant to Section 3.2, as adjusted pursuant to Section 3.3(a);

(b) The opinions of counsel and certificates contemplated by Section 7.2(h) and (j);

(c) Ancillary Agreements, duly executed by Buyer;

(d) Copies, certified by the Secretary or Assistant Secretary of Buyer, of resolutions authorizing the execution and delivery of this Agreement, and all of the agreements and instruments to be executed and delivered by Buyer in connection herewith, and the consummation of the transactions contemplated hereby;

(e) A certificate of the Secretary or Assistant Secretary of Buyer identifying the name and title and bearing the signatures of the officers of Buyer authorized to execute and deliver this Agreement, and the other agreements contemplated hereby;

(f) A certificate of good standing with respect to Buyer, issued by the Secretary of the State of Maryland;

(g) A certificate of authority of Buyer (or its assignee of this Agreement) to do business in New York, issued by the Secretary of State of New York;

(h) All such other instruments of assumption as shall, in the reasonable opinion of Seller and its counsel, be necessary for Buyer to assume the Assumed Liabilities and Obligations in accordance with this Agreement;

(i) Copies of any and all governmental and other third party consents, waivers or approvals obtained by Buyer with respect to the transfer of the Purchased Assets, or the consummation of the transactions contemplated by this Agreement;

(j) A copy of the Post-Closing Decommissioning Trust Agreement; and

(k) Such other agreements, documents, instruments and writings as are required to be delivered by Buyer at or prior to the Closing Date pursuant to this Agreement, or otherwise reasonably required in connection herewith.

Section 3.8 Delivery of DOE Credit Support. At the Closing, Seller will deliver or cause to be delivered, to Buyer, the DOE Credit Support (in any permitted form, as determined by Seller).

ARTICLE 4

REPRESENTATIONS AND WARRANTIES OF SELLER

Seller hereby represents and warrants to Buyer as follows:

Section 4.1 Organization. Seller is a corporation duly organized, validly existing and in good standing under the laws of the State of New York and has all requisite corporate power and authority to own, lease, and operate its properties and to carry on its business as is now being conducted. Copies of the Certificate of Incorporation and By-laws of Seller, each as amended to date, have heretofore been made available to Buyer.

Section 4.2 Authority Relative to this Agreement. Seller has full corporate power and authority to execute and deliver this Agreement and the Ancillary Agreements and to consummate the transactions contemplated hereby and thereby. The execution and delivery of this Agreement and the Ancillary Agreements and the consummation of the transactions contemplated hereby and thereby have been duly and validly authorized by all necessary corporate action required on the part of Seller and no other corporate proceedings on the part of Seller are necessary to authorize this Agreement and the Ancillary Agreements or to consummate the transactions contemplated hereby and thereby. This Agreement has been duly and validly executed and delivered by Seller and at Closing, the Ancillary Agreements will be duly and validly executed and delivered by Seller, and assuming that this Agreement and the applicable Ancillary Agreements constitute a valid and binding agreement of Buyer and subject to the receipt of Seller's Required Regulatory Approvals, this Agreement and the Ancillary Agreements constitute the legal, valid and binding agreement of Seller, enforceable against Seller in accordance with their respective terms.

Section 4.3 Consents and Approvals; No Violation.

(a) Subject to the receipt of the third-party consents set forth in Schedule 4.3(a) and the Seller's Required Regulatory Approvals, neither the execution and delivery of this Agreement or the Ancillary Agreements by Seller nor the consummation of the transactions contemplated hereby or thereby will (i) conflict with or result in the breach or violation of any provision of the Certificate or Articles of Incorporation or Bylaws of Seller; (ii) result in a default (or give rise to any right of termination, cancellation or acceleration) under any of the terms, conditions or provisions of any note, bond, mortgage, indenture, license, agreement or other instrument or obligation to which Seller is a party or by which Seller, or any of the Purchased Assets, may be bound, except for such defaults (or rights of termination, cancellation or acceleration) as to which requisite waivers or consents have been obtained or which would not, individually or in the aggregate, create a Material Adverse Effect; or (iii) constitute violations of any order, writ, injunction, decree, statute, rule or regulation applicable to Seller, or any of its assets, which violation, individually or in the aggregate, would create a Material Adverse Effect.

(b) Except as set forth in Schedule 4.3(b) (the filings and approvals referred to in Schedule 4.3(b) are collectively referred to as the "Seller's Required Regulatory Approvals"), no declaration, filing or registration with, or notice to, or authorization, consent or approval of any Governmental Authority is necessary for the execution and delivery of this Agreement or the Ancillary Agreements or the consummation by Seller of the transactions contemplated hereby or thereby, other than (i) such declarations, filings, registrations, notices, authorizations, consents or approvals which, if not obtained or made, will not, individually or in the aggregate, create a Material Adverse Effect, or (ii) such declarations, filings, registrations, notices, authorizations, consents or approvals which become applicable to Seller as a result of the specific regulatory status of Buyer (or any of its Affiliates) or the result of any other facts that specifically relate to the business or activities in which Buyer (or any of its Affiliates) is or proposes to be engaged. Seller has no Knowledge of any facts or circumstances that make it reasonably likely that Seller's Required Regulatory Approvals will not be obtained.

Section 4.4 Reports. Since January 1, 2002, Seller has filed or caused to be filed with the SEC, the applicable state or local utility commissions or regulatory bodies, the NRC, the DOE and the FERC, as the case may be, all material forms, statements, reports and documents (including all exhibits, amendments and supplements thereto) required to be filed by them with respect to the Purchased Assets or the ownership or operation thereof under each of the Securities Act, the Exchange Act, the applicable state public utility laws, the Federal Power Act, the Holding Company Act, the Atomic Energy Act, the Energy Reorganization Act, and the Price-Anderson Act and the respective rules and regulations thereunder, except for such filings the failure of which to make would not, individually or in the aggregate, reasonably be expected to have a Material Adverse Effect. All such filings complied in all material respects with all applicable requirements of the appropriate act and the rules and regulations thereunder in effect on the date each such report was filed, and there are no material misstatements or omissions relating to the Purchased Assets in any such report; provided, however, Seller shall not be deemed to be making any representation or warranty to Buyer hereunder concerning the financial statements of Seller or any Affiliate of Seller contained in any such reports.

Section 4.5 Undisclosed Liabilities. Except as set forth in Schedule 4.5, the Purchased Assets are not subject to any material Liability that has not been accrued or reserved against in Seller's financial statements as of the end of the most recent fiscal quarter for which such statements are available or disclosed in the notes thereto in accordance with generally accepted accounting principles consistently applied.

Section 4.6 Absence of Certain Changes or Events. Since January 1, 2003, except as set forth in Schedule 4.6 or Schedule 4.15(a)(i), there has not been: (a) any Material Adverse Effect; (b) any damage, destruction or casualty loss, whether or not covered by insurance, which, individually or in the aggregate, created a Material Adverse Effect; or (c) any agreement, commitment or transaction entered into by Seller that is material to the ownership or operation of the Purchased Assets, taken as a whole, and remains in full force and effect on the date hereof.

Section 4.7 Title and Related Matters. Except as set forth in Schedule 4.7, Seller holds title, insurable at regular rates by a nationally recognized title insurance company, to the Real Property to be conveyed by it hereunder free and clear of all Encumbrances, other than the Permitted Encumbrances; provided, however, that Seller makes no representation or warranty with respect to title to groundwater. To the Knowledge of Seller, there are no public or private special assessments threatened against the Purchased Assets. The Real Property, the Cooling Tunnel Easement, and the real property interests to be transferred to Buyer by the Easements constitute all of the real property interests necessary to operate the Facilities as currently operated. Seller has good and valid title to the Purchased Assets not constituting Real Property free and clear of all Encumbrances, except Permitted Encumbrances.

Section 4.8 Real Property Agreements. Schedule 4.8 lists, as of the date of this Agreement, all real property leases, easements, licenses and other rights in real property including all material amendments thereto (exclusive of non-current term extensions) (collectively, the "Real Property Agreements") to which Seller is a party (directly or as a successor or assignee) and which affect all or any part of any Real Property and (i) provide for annual payments of more than $50,000 or (ii) are material to the ownership or operation of the Purchased Assets. Except as set forth in Schedule 4.8, all such Real Property Agreements are valid, binding and enforceable in accordance with their terms, and are in full force and effect; there are no existing material defaults by Seller or any other party thereunder; and no event has occurred which (whether with or without notice, lapse of time or both) would constitute a material default by Seller or any other party thereunder. Except as otherwise set forth in Schedule 4.8, all such Real Property Agreements shall be transferred and assigned by Seller to Buyer on the Closing Date.

Section 4.9 Insurance. Except as set forth in Schedule 4.9, all material policies of property damage, fire, liability, nuclear property damage, worker's compensation and other forms of insurance owned or held by Seller or its Affiliates and insuring the Purchased Assets are in full force and effect, all premiums with respect thereto covering all periods up to and including the date as of which this representation is being made have been paid (other than retroactive premiums which may be payable with respect to the Price Anderson secondary protection plan or NEIL policies), and no written notice of cancellation, non-renewal or termination has been received with respect to any such policy which was not replaced on substantially similar terms prior to the date of such cancellation. Except as described in Schedule 4.9, as of the date of this Agreement, to the Knowledge of Seller, Seller has not been refused any insurance with respect to the Purchased Assets nor has its coverage been limited by any insurance carrier to which it has applied for any such insurance or with which it has carried insurance on or after September 11, 2001, and all required notices have been sent to insurers to preserve all material claims under the aforementioned insurance policies.

Section 4.10 Environmental Matters. With respect to the Purchased Assets and the ownership or operation thereof by Seller, except as disclosed in Schedule 4.10:

(a) Seller has obtained and holds all material Environmental Permits used in or necessary for the ownership and operation of the Facilities and the Purchased Assets as conducted prior to the Closing Date;

(b) Seller is in compliance in all material respects with all terms, conditions and provisions of, and has not received within the past five (5) years any written notice from any Governmental Authority that it is not or has not been in compliance with (i) all applicable Environmental Laws and (ii) all material Environmental Permits except, in each case, with respect to violations which, individually or in the aggregate, would not reasonably be expected to have a Material Adverse Effect;

(c) There are no Environmental Claims pending against Seller or, to the Knowledge of Seller, threatened, with respect to the Purchased Assets and Seller does not have Knowledge of any facts or circumstances which are reasonably likely to form the basis for any material Environmental Claim against Seller with respect to the Purchased Assets;

(d) No Releases of Hazardous Substances have occurred at, from, on, or under the Site, and no Hazardous Substances are present on or migrating from the Site, that are reasonably likely to give rise to a material Environmental Claim against Seller or require any Remediation, except for such Releases that, individually or in the aggregate, would not reasonably be expected to have a Material Adverse Effect

(e) Neither the Site nor any portion thereof is a current or, to the Knowledge of Seller, proposed Environmental Clean-up Site and Seller has not, to its

Knowledge, transported or arranged for treatment, storage, handling, disposal or transportation of any Hazardous Substances from the Site to any location which is an Environmental Clean-up Site;

(f) There are no Encumbrances arising under or pursuant to any Environmental Law with respect to the Purchased Assets and, to the Knowledge of Seller, there are no facts, circumstances, or conditions that are reasonably likely to restrict, encumber, or result in the imposition of special conditions under any Environmental Law with respect to the ownership, occupancy, development, use, or transferability of the Purchased Assets, except those facts, circumstances or conditions relating to the status of the Purchased Assets as a nuclear facility;

(g) There are no (i) underground storage tanks, active or abandoned, or (ii) polychlorinated-biphenyl-containing equipment;

(h) There have been no environmental audits or assessments with respect to the Purchased Assets conducted in the last five (5) years by, on behalf of, or which are in the possession of Seller or its Affiliates which have not been made available to Buyer prior to execution of this Agreement; and

(i) There have been no claims by Seller against comprehensive general liability or excess insurance carriers for any Loss resulting from, relating to or arising from Environmental Claims with respect to the Purchased Assets.

The representations and warranties made by Seller in this Section 4.10 are the exclusive representations and warranties made to Buyer relating to environmental matters.

Section 4.11 Labor Matters. As of the date hereof, there is no current collective bargaining agreement which relates to the Ginna Employees. Each Ginna Employee and each other individual that provides services at the Facilities or otherwise in support of the Purchased Assets ("Other Plant Personnel") is performing, and is qualified, licensed, certified or trained, in accordance with applicable government requirements or standards to perform the duties and responsibilities of their current job assignment, and each has the appropriate nuclear power plant access authorizations, where required. For all purposes, including but not limited to the payment of Taxes and coverage under any Benefit Plan, any individual who performs services with respect to the Facilities or the Purchased Assets has been and is currently properly classified by Seller under applicable Laws as either a Ginna Employee or an independent contractor, as the case may be. Except as described in Schedule 4.11: (i) except for such matters as will not, individually or in the aggregate, create a Material Adverse Effect, Seller is in compliance in all material respects with all applicable Laws respecting employment and employment practices, terms and conditions of employment (including, without limitation, Benefit Plans) and wages (including, without limitation, Laws pertaining to non-discrimination in compensation) and hours relating to the Ginna Employees have been complied with in all material respects; (ii) as of the date hereof, no notice, written or to the

Knowledge of Seller, otherwise, has been received from any Governmental Authority of any unfair labor practice charge or complaint against Seller or any Affiliate thereof pending or, to Seller's Knowledge, threatened, before the National Labor Relations Board or any other Governmental Authority or entity with respect to Ginna Employees; (iii) as of the date hereof, there are no written complaints of discrimination or retaliation pending, or to Seller's Knowledge, threatened, with the U.S. Equal Employment Opportunity Commission or state or local counterpart, the U.S. Department of Labor (including the Office of Federal Contract Compliance Programs), the NRC or any other Governmental Authority or entity related to services performed by Ginna Employees or, to the Knowledge of Seller, Other Plant Personnel; (iv) as of the date hereof, there is no noticed or, to the Knowledge of Seller, threatened or pending audit by the Office of Federal Contract Compliance Programs of the affirmative action plans which would pertain to the Facilities or the Purchased Assets and the Ginna Employees; (v) as of the date hereof, neither Seller nor any Affiliate thereof has any Knowledge of any claim of representation by a third party, organizing drive by a third party seeking to represent all or any portion of the Ginna Employees, or representation petition concerning the workforce at the Purchased Assets; and (vi) as of the date hereof, Seller has not received any written notice or, to Knowledge of the Seller, non-written notice, that any complaint has been filed with or is pending before the United States Department of Labor with regard to wages or compensation offered, paid or otherwise due and owing to any Ginna Employee.

Section 4.12 <u>ERISA; Benefit Plans.</u>

(a) Schedule 4.12(a) lists each employee benefit plan, including each employee benefit plan as defined in Section 3(3) of ERISA, and each other plan, contract, agreement, arrangement or policy, whether written or oral, qualified or non-qualified, providing for (i) compensation, severance benefits, bonuses, profit-sharing or other forms of incentive compensation; (ii) vacation, holiday, sickness or other time-off; (iii) health, medical, dental, disability, life, accidental death and dismemberment, employee assistance, educational assistance, relocation or fringe benefits or perquisites, including post-employment benefits; and (iv) deferred compensation, defined benefit or defined contribution, retirement or pension benefits, or equity grants that covers any Ginna Employee, or that is maintained, administered or with respect to which contributions are made by Seller or an ERISA Affiliate in respect of Ginna Employees ("<u>Benefit Plans</u>"). True, correct, and complete copies of all such Benefit Plans, including all amendments thereto and other information regarding benefit changes that have been previously communicated, have been made available to Buyer, and the Benefit Plans are being administered in accordance with such documents. To Seller's Knowledge, there have been no communications to Ginna Employees concerning any increase to the cap on the employer's shares of the cost for RG&E Retiree Coverages. Contractors and Other Plant Personnel for whom the Seller or any ERISA Affiliate does not furnish a Form W-2 for such services do not participate in or otherwise benefit from any of the Benefit Plans.

(b) Except as set forth in Schedule 4.12(b), Seller and the ERISA Affiliates have fulfilled their respective obligations under the minimum funding requirements of Section 302 of ERISA and Section 412 of the Code with respect to each Benefit Plan that is an "employee pension benefit plan" as defined in Section 3(2) of ERISA and to which Section 302 of ERISA applies. To Seller's Knowledge, except as set forth in Schedule 4.12(b), neither Seller nor any ERISA Affiliate has incurred any Liability under Sections 4062(b), 4063 or 4064 of ERISA to the PBGC in connection with any Benefit Plan that is subject to Title IV of ERISA, nor any withdrawal Liability to any multi-employer pension plan under Section 4201 et. seq. of ERISA or to any multi-employer welfare benefit plan. Each Benefit Plan which is intended to be qualified within the meaning of Code Section 401(a) is so qualified and has received a favorable determination letter as to its qualification under all applicable Laws including GUST (and if no favorable determination letter has yet been issued, such Benefit Plan was timely submitted), has timely adopted the requisite amendments under the Economic Growth and Tax Relief Reconciliation Act of 2001; and nothing has occurred, whether by action or failure to act, that could reasonably be expected to cause the loss of IRS qualification; and the most recent IRS determination letters have been furnished by Seller to Buyer. To Knowledge of Seller, there is no reportable event (as described in Section 4043 of ERISA) with respect to any Benefit Plan that is required to be reported to the PBGC and no prohibited transaction (as described in Section 406 of ERISA and Section 4975 of the Code) has occurred with respect to any Benefit Plan, except as set forth in Schedule 4.12(b). With respect to each Benefit Plan from which Buyer will receive assets in a transaction under Section 414(l) of the Code, receive assets in a trustee-to-trustee transfer or participant rollover under Section 401(a)(31) of the Code: (i) such Benefit Plan has been maintained in material compliance with all applicable Laws, including ERISA, the Code, and the Securities Act and the Exchange Act; (ii) such Benefit Plan may be amended, terminated, or otherwise modified by the sponsoring employer to the greatest extent permitted by applicable Laws (including, without limitation, elimination of future accruals under any such Benefit Plan), and, to Knowledge of Seller, no employee communication or provision in any document governing such Benefit Plan has failed to reserve effectively the right of the sponsoring employer (including, after its assumption of such Benefit Plan, Buyer) to terminate, or make any amendment or modification to such Benefit Plan; (iii) Seller has not made any commitment to establish any new Benefit Plan, to modify any Benefit Plan (except as required under applicable Laws), nor has any intention to do so been communicated to any Ginna Employees; (iv) no actions, suits or claims (other than routine claims for benefits in the ordinary course) are pending or, to the Knowledge of the Seller, threatened; (v) no facts or circumstances exist that could give rise to any actions, suits or claims; (vi) no administrative investigation, audit or other administrative proceeding by the Department of Labor, the PBGC, the IRS or other Governmental Authority are pending, in progress or, to the Knowledge of the Seller, threatened; (vii) as of the date hereof, Seller does not have an application pending to the IRS under the Employee Plans Compliance Resolution System; and (viii) if Seller has previously made such application and a compliance statement has been issued, Seller has signed such statement and made the applicable correction or will make the applicable correction within the requisite time period.

(c) Neither Seller nor any ERISA Affiliate or parent or successor corporation, within the meaning of Section 4069(b) of ERISA, has engaged in any transaction that may be disregarded under Section 4069 or Section 4212(c) of ERISA. No Benefit Plan or ERISA Affiliate Plan is a multi-employer plan.

Section 4.13 Real Property; Plant and Equipment.

(a) Schedule 4.13(a) contains a substantially complete and accurate legal description of the part of the Real Property included in the Purchased Assets that consists of the land that comprises the Site. All Encumbrances on the Real Property (other than Permitted Encumbrances) shall be released on or before the Closing Date. Complete and correct copies of any current surveys in Seller's possession and any policies of title insurance currently in force and in the possession of Seller with respect to the Real Property have heretofore been delivered by Seller to Buyer.

(b) Schedule 4.13(b) contains a description of the major equipment components and personal property included in the Purchased Assets.

(c) Except as set forth in Schedule 4.13(c), the Purchased Assets conform in all material respects to the technical specifications included in the NRC License in accordance with the requirements of 10 C.F.R. 50.36 and the FSAR and are being operated in all material respects in conformance with all material applicable requirements under the Atomic Energy Act, the Energy Reorganization Act, and the rules, regulations, orders and licenses issued thereunder. The Purchased Assets constitute all of the real property and tangible assets necessary to operate the Facilities in substantially the same manner as they have been operated to date.

(d) The Business Books and Records are true, complete and correct in all material respects and have been maintained in accordance with good business practices. The business and operating budget projections provided to the Buyer were prepared in good faith based on assumptions Seller believed to be reasonable as of the date thereof and in light of the circumstances in which they were prepared.

Section 4.14 Condemnation. Except as set forth in Schedule 4.14, neither the whole nor any part of the Real Property, or any other real property or rights leased, licensed, used or occupied by Seller in connection with the ownership or operation of the Purchased Assets is subject to any pending suit for condemnation or other taking by any Governmental Authority, and no such condemnation or other taking has been threatened.

Section 4.15 Certain Contracts and Arrangements.

(a) Except for Seller's interests in and rights under (i) those purchase orders, contracts, agreements, licenses and leases relating to the ownership, operation and maintenance of the Purchased Assets, which are listed in Schedule 4.15(a)(i) or the other schedules to this Agreement or that are made available to Buyer pursuant to the last sentence of Section 4.12(a), (ii) those contracts, agreements, commitments and understandings of Seller relating to the procurement or fabrication of Nuclear Fuel, a complete list of which is included on Schedule 4.15(a)(ii) ("Fuel Contracts"), (iii) contracts, agreements, personal property leases, commitments, understandings or instruments in which all obligations of Seller will be fully performed or terminated prior to the Closing Date, (iv) Non-material Contracts, and (v) the Ancillary Agreements, Seller is not a party to any written contract, agreement, personal property lease, commitment, understanding or instrument which is material to the ownership or operation of the Purchased Assets or provides for the sale of capacity, energy or ancillary services from any of the Purchased Assets (whether or not entered into in the ordinary course of business).

(b) Except as disclosed in Schedule 4.15(b), each of the agreements listed on Schedules 4.15(a)(i) and 4.15(a)(ii): (i) constitutes the legal, valid and binding obligation of Seller enforceable in accordance with its terms, (ii) is in full force and effect, and (iii) may be transferred or assigned to Buyer at the Closing without consent or approval of the other parties thereto, and will continue in full force and effect thereafter in accordance with its terms, in each case without breaching the terms thereof or resulting in the forfeiture or impairment of any material rights thereunder. The Agreements listed in Schedules 4.15(a)(i) and 4.15(a)(ii) constitute the agreements that are necessary collectively to permit Seller to own, use, maintain and operate the Purchased Assets and the Facilities in accordance with Good Utility Practice and applicable Laws.

(c) Except as set forth in Schedule 4.15(c), there is not, under any of the agreements listed on Schedule 4.15(a)(i) and (a)(ii), any breach, violation, default or event which, with notice or lapse of time or both, would constitute a default on the part of Seller, or to the Knowledge of Seller, on the part of any of the parties thereto, except such events of default and other events as to which requisite waivers or consents have been obtained or which would not, individually or in the aggregate, create a Material Adverse Effect.

Section 4.16 Legal Proceedings, etc. Except as set forth in Schedule 4.16 or in any filing made by Seller or any of its Affiliates prior to the date hereof pursuant to the Securities Act, the Exchange Act or the Atomic Energy Act, there are no claims, actions, proceedings or investigations pending or to the Knowledge of Seller, threatened against or relating to Seller before any court, arbitrator, mediator or Governmental Authority which, individually or in the aggregate, would reasonably be expected to (i) result in a Material Adverse Effect, (ii) prohibit or restrain the performance of this Agreement or any of the Ancillary Agreements or the consummation of the transactions contemplated hereby or thereby, or (iii) result in a material claim against Buyer for damages as a result of Seller entering into this Agreement or any of the Ancillary Agreements, or of the consummation of the transactions contemplated hereby or thereby. Except as set forth in Schedule 4.16 or in any filing made by Seller or any of its Affiliates prior to the date hereof pursuant to the Securities Act, the Exchange Act or the Atomic Energy Act, Seller is not subject to any outstanding judgment, rule, order, writ, injunction or decree of any court, arbitrator or Governmental Authority which, individually or in the aggregate, would reasonably be expected to have a Material Adverse Effect.

Section 4.17 Permits.

(a) Seller has all permits, licenses, registrations, certificates, franchises and other governmental authorizations, consents and approvals, other than with respect to permits under Environmental Laws referred to in Section 4.10 hereof or licenses issued by the NRC referred to in Section 4.18 hereof (collectively, "Permits"), used in, or necessary for the ownership and operation of, the Purchased Assets as presently conducted or as required by Law, except for such Permits the failure of which to have would not reasonably be expected to have a Material Adverse Effect. Except as set forth in Schedule 4.17(a), Seller has not received any written notification which remains unresolved that it is in violation of any of such Permits, or any Law applicable to the Purchased Assets, except for notifications of violations which would not, individually or in the aggregate, reasonably be expected to have a Material Adverse Effect. Seller is in compliance with all Permits and Laws of any Governmental Authority applicable to the Purchased Assets, except for violations which, individually or in the aggregate, would not reasonably be expected to have a Material Adverse Effect.

(b) Schedule 4.17(b) sets forth all material Permits and Environmental Permits other than Transferable Permits (which are set forth on Schedule 1.1(173)) applicable to the Purchased Assets.

Section 4.18 NRC Licenses.

(a) Seller has all licenses, permits, and other consents and approvals applicable to Seller that are issued by the NRC and are necessary to the ownership and operation of the Purchased Assets as presently operated, pursuant to the requirements of all Nuclear Laws and all such licenses are in full force and effect. Except as set forth in Schedule 4.18(a), Seller has not received any written notification which remains unresolved that it is in violation of any of such license, or any order, rule, regulation, or decision of the NRC with respect to the Purchased Assets, except for notifications of violations which would not, individually or in the aggregate, reasonably be expected to have a Material Adverse Effect. Seller is in compliance with all Nuclear Laws and all orders, rules, regulations, or decisions of NRC applicable to it with respect to the Purchased Assets, except for violations which, individually or in the aggregate, would not reasonably be expected to have a Material Adverse Effect.

(b) Schedule 4.18(b) sets forth all material permits, licenses, and other consents and approvals issued by the NRC applicable to the Purchased Assets.

Section 4.19 Regulation as a Utility. Seller is an electric utility company within the meaning of the Holding Company Act, a public utility within the meaning of the Federal Power Act and an electric utility within the meaning of the NRC regulations implementing the Atomic Energy Act. Except with respect to local tax and zoning laws, Seller is not, as a result of its ownership or operation of the Purchased Assets, subject to regulation as a public utility or public service company (or similar designation) by any state of the United States other than New York, any foreign country or any municipality or any political subdivision of the foregoing.

Section 4.20 Taxes. With respect to the Purchased Assets, (i) all material Tax Returns of the Seller required to be filed for taxable periods ended prior to the Closing Date regarding the ownership or operation of the Purchased Assets have been filed, and (ii) all material Taxes shown to be due on such Tax Returns have been paid, except where such Taxes are being contested in good faith through appropriate proceedings. Except as provided in Schedule 4.20(a), no notice of deficiency or assessment has been received from any taxing authority with respect to liabilities for Taxes of the Seller in respect of the Purchased Assets which has not been fully paid or finally settled. There are no Encumbrances for Taxes upon the Purchased Assets, except for Encumbrances for Taxes not yet due and payable and Encumbrances for Taxes that are being contested in good faith. There is no unpaid material Tax on Seller's ownership, operation, or use of the Purchased Assets for which the Buyer could become liable. Schedule 4.20 sets forth the Tax jurisdictions in which Seller owns assets or conducts business that require a notification to a taxing authority of the transactions contemplated by this Agreement, if the failure to make such notification, or obtain Tax clearances in connection therewith, would either require Buyer to withhold any portion of the Purchase Price or would subject Buyer to any Liability for any Taxes of Seller. Except as provided in Schedule 4.20(b), there are no outstanding agreements or waivers extending the applicable statutory periods of limitations for Taxes associated with the Purchased Assets for any period.

Section 4.21 Qualified Decommissioning Funds.

(a) With respect to all periods prior to the Closing Date: (i) Seller's Qualified Decommissioning Fund is a trust, validly existing under the laws of the State of New York with all requisite authority to conduct its affairs as it now does; (ii) Seller's Qualified Decommissioning Fund satisfies the requirements necessary for such fund to be treated as a "Nuclear Decommissioning Reserve Fund" within the meaning of Code Section 468A(a) and as a "Nuclear Decommissioning Fund" and a "Qualified Nuclear Decommissioning Fund" within the meaning of Treas. Reg. § 1.468A-1(b)(3); (iii) such Fund is in compliance in all material respects with all applicable rules and regulations of the NRC, the NYPSC and the IRS, and Seller's Qualified Decommissioning Fund has not engaged in any acts of "self-dealing" as defined in Treas. Reg. § 1.468A-5(b)(2); (iv) no "excess contribution," as defined in Treas. Reg. § 1.468A-5(c)(2)(ii), has been made to Seller's Qualified Decommissioning Fund which has not been withdrawn within the period provided under Treas. Reg. § 1.468A-5(c)(2)(i); and (v) Seller has made timely and valid elections to make annual contributions to the Qualified Decommissioning Fund since 1990 and Seller has heretofore delivered copies of such elections to Buyer.

(b) Seller has heretofore delivered to Buyer a copy of Seller's Decommissioning Trust Agreement as in effect on the date of this Agreement. Seller agrees not to amend Seller's Decommissioning Trust Agreement between the date of this Agreement and the Closing Date without Buyer's prior written consent, which shall not be unreasonably withheld, except for any amendment which may be required to be made to the Seller's Decommissioning Trust Agreement by the NRC final rule on decommissioning trust agreements published in the Federal Register on December 24, 2002 or to permit the transfers referred to in Section 6.12 or to permit return to Seller of Decommissioning Funds in excess of the Decommissioning Target.

(c) Subject only to Seller's Required Regulatory Approvals, Seller and the Trustee have, or as of Closing will have, all requisite authority to cause the assets of the Qualified Decommissioning Fund to be transferred to the Trustee of the Post-Closing Decommissioning Trust Agreement.

(d) With respect to all periods prior to the Closing Date, (i) Seller and/or the Trustee of Seller's Qualified Decommissioning Fund has/have filed or caused to be filed with the NRC, the IRS and any state or local authority all material forms, statements, reports, documents (including all exhibits, amendments and supplements thereto) required to be filed by such entities; and (ii) there are no interim rate orders that may be retroactively adjusted or retroactive adjustments to interim rate orders that may affect amounts that Buyer may contribute to the Qualified Decommissioning Fund or may require distributions to be made from the Qualified Decommissioning Fund. Seller has delivered to Buyer a copy of the schedule of ruling amounts most recently issued by the IRS for the Qualified Decommissioning Fund and a complete copy of the request that was filed with the IRS to obtain such schedule of ruling amounts and a copy of any pending request for revised ruling amounts, in each case together with all exhibits, amendments and supplements thereto. Any amounts contributed to the Qualified Decommissioning Fund while such request is pending before the IRS and which turn out to exceed the applicable amounts provided in the schedule of ruling amounts issued by the IRS will be withdrawn from the Qualified Decommissioning Fund within the period provided under Treas. Reg. Section 1.468A-5(c)(2)(i).

(e) Seller has made available to Buyer a statement of assets and liabilities verified by the Trustee for the Seller's Qualified Decommissioning Funds as of December 31, 2002, as of September 30, 2003 and will make such a statement as of the second Business Day before Closing available prior to Closing, and they present fairly as of such dates the financial position of each of the Qualified Decommissioning Funds. Seller has made available to Buyer information from which Buyer can determine the Tax Basis of all assets in the Seller's Qualified Decommissioning Fund as of the second Business Day before Closing.

(f) Seller has made available to Buyer all material contracts and agreements to which the Trustee of Seller's Qualified Decommissioning Fund, in its capacity as such, is a party.

(g) With respect to all taxable periods prior to the Closing Date, Seller's Qualified Decommissioning Fund has filed all material Tax Returns required to be filed, including but not limited to returns for estimated Income Taxes, such Tax Returns are true, correct and complete in all material respects, and all Taxes shown to be due on such Tax Returns have been paid in full. Except as shown in Schedule 4.21, no notice of deficiency or assessment has been received from any taxing authority with respect to any Liability for Taxes of Seller's Qualified Decommissioning Fund which have not been fully paid or finally settled, and any such deficiency shown in such Schedule 4.21 is being contested in good faith through appropriate proceedings. Except as set forth in Schedule 4.21, there are no outstanding agreements or waivers extending the applicable statutory periods of limitations for any Taxes associated with the Qualified Decommissioning Funds for any period.

Section 4.22 Nonqualified Decommissioning Fund.

(a) With respect to all periods prior to the Closing Date, the Seller's Nonqualified Decommissioning Fund is a trust validly existing under the laws of the State of New York with all requisite authority to conduct its affairs as it now does. Seller's Nonqualified Decommissioning Fund is in full compliance in all material respects with all applicable rules and regulations of the NRC and the NYPSC. The Seller's Nonqualified Decommissioning Fund is classified as a grantor trust owned by Seller under Section 671 to 677 of the Code.

(b) Subject only to the Seller's Required Regulatory Approvals, Seller has or as of the Closing will have all requisite authority to cause all or a portion of the assets of the Seller's Nonqualified Decommissioning Fund to be transferred to the Trustee of the Post-Closing Decommissioning Trust Agreement pursuant to Section 6.12 hereof.

(c) With respect to all periods prior to the Closing Date, Seller and the Trustee of the Seller's Nonqualified Decommissioning Fund have filed or caused to be filed with the NRC and any state or local authority all material forms, statements, reports, documents (including all exhibits, amendments and supplements thereto) required to be filed by either of them.

(d) Seller has made available to Buyer a statement of assets and liabilities verified by the Trustee of the Seller's Nonqualified Decommissioning Fund as of December 31, 2002, as of September 30, 2003 and will make available such a statement as of the second Business Day before Closing available prior to Closing, and they represent fairly as of such dates the financial position of the Nonqualified Decommissioning Funds. Seller has made available to Buyer all contracts and agreements to which the Trustee of the Nonqualified Decommissioning Fund, in its capacity as such, is a party.

Section 4.23 WARN Act. Seller has not engaged in a "plant closing" or "mass layoff," as such terms are defined in the WARN Act, prior to the Closing Date.

Section 4.24 Intellectual Property. Seller has not received written notice of any claims or demands of any other Person pertaining to any of the Intellectual Property and no proceedings have been instituted, or are pending or, to Seller's Knowledge, threatened, which challenge the rights of Seller in respect thereof. To the Knowledge of Seller, none of the Intellectual Property infringes any intellectual property of any other Person and Seller is not making unauthorized use of any confidential information or trade secrets of any Person, including without limitation, any former employer of any past or present employee of Seller in connection with the operation of Ginna.

Section 4.25 Zoning Classification. The Real Property is zoned as set forth in Schedule 4.25 and is currently zoned in zoning categories which permit the operation of the Facilities as currently operated, as a matter of right. Seller has not requested, applied for, or given its consent to, and Seller has no Knowledge of, any pending zoning variance or change with respect to the zoning of the Real Property. To Seller's Knowledge, there exist no outstanding covenants or agreements in connection with the zoning of the Real Property or any portion thereof which would bind or require Buyer to perform any actions or pay any monies in connection therewith.

Section 4.26 Utilities. The sewer and water systems and all other utilities that currently service the Real Property are sufficient for the operation of the Facilities as currently operated. To Seller's Knowledge, Seller has no reason to believe that such systems and utilities will not be sufficient to continue to operate the Facilities, and, to Seller's Knowledge, such services shall exist on the Closing Date. Seller has no Knowledge of and has not received any notice of the curtailment of any utility service supplied to the Real Property. To Seller's Knowledge, all water and all gas, electrical, steam, telecommunication, sanitary and storm sewer and drainage lines, systems and hook ups and all other utilities and public and quasi-public improvements located upon, under, at or adjacent to the Real Property required by any applicable Laws or otherwise necessary for the operation of the Facilities as currently operated are installed and connected under valid permits.

EXCEPT FOR THE REPRESENTATIONS AND WARRANTIES SET FORTH IN THIS ARTICLE 4, THE PURCHASED ASSETS ARE BEING SOLD AND TRANSFERRED "AS IS, WHERE IS," AND SELLER IS NOT MAKING ANY OTHER REPRESENTATIONS OR WARRANTIES, WRITTEN OR ORAL, STATUTORY, EXPRESS OR IMPLIED, CONCERNING THE PURCHASED ASSETS, INCLUDING, IN PARTICULAR, ANY WARRANTY OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE, ALL OF WHICH ARE HEREBY EXPRESSLY EXCLUDED AND DISCLAIMED.

ARTICLE 5

REPRESENTATIONS AND WARRANTIES OF BUYER AND BUYER'S PARENT

Each of Buyer and Buyer's Parent represents and warrants with respect to itself to Seller as follows:

Section 5.1 Organization; Qualification. Buyer is a limited liability company duly formed, validly existing and in good standing under the laws of the State of Maryland. Buyer's Parent is a corporation duly formed, validly existing and in good standing under the laws of the State of Maryland. Each of Buyer and Buyer's Parent has all requisite corporate power and authority to own, lease and operate its properties and to carry on its business as is now being conducted. Buyer has heretofore delivered to Seller complete and correct copies of its articles of organization as currently in effect. Buyer is, or on the Closing Date will be, qualified to conduct business in the State of New York.

Section 5.2 Authority Relative to this Agreement. Each of Buyer's Parent and Buyer has full corporate power and authority to execute and deliver this Agreement and the Ancillary Agreements to which it is a party and to consummate the transactions contemplated hereby or thereby. The execution and delivery of this Agreement and the Ancillary Agreement and the consummation of the transactions contemplated hereby or thereby, have been duly and validly authorized by all necessary corporate action required on the part of each of Buyer's Parent and Buyer and no other corporate proceedings on the part of Buyer's Parent or Buyer are necessary to authorize this Agreement and the Ancillary Agreements or to consummate the transactions contemplated hereby or thereby. This Agreement has been duly and validly executed and delivered by each of Buyer's Parent and Buyer, and assuming that this Agreement constitutes a valid and binding agreement of Seller and subject to the receipt of Buyer's Required Regulatory Approvals, constitutes a valid and binding agreement of each of Buyer's Parent and Buyer, enforceable against each of Buyer's Parent and Buyer in accordance with its terms.

Section 5.3 Consents and Approvals; No Violation.

(a) Subject to the receipt of the third-party consents set forth in Schedule 5.3(a) and the Buyer's Required Regulatory Approvals, neither the execution and delivery of this Agreement and the Ancillary Agreements by Buyer or Buyer's Parent nor the consummation of the transactions contemplated hereby or thereby will (i) conflict with or result in any breach of any provision of the articles of organization or operating agreement of Buyer and Buyer's Parent, (ii) require any consent, approval, authorization or permit of, or filing with or notification to, any Governmental Authority, (iii) result in a default (or give rise to any right of termination, cancellation or acceleration) under any of the terms, conditions or provisions of any note, bond, mortgage, indenture, agreement, lease or other instrument or obligation to which Buyer or Buyer's Parent is a party or by which any of its assets may be bound, except for such defaults (or rights of termination, cancellation or acceleration) as to which requisite waivers or consents have been obtained or which would not, individually or in the aggregate, have a material adverse effect on the ability of Buyer or Buyer's Parent to perform its obligations hereunder ("Buyer Material Adverse Effect"), or (iv) violate any Laws applicable to Buyer, which violations, individually or in the aggregate, would create a Buyer Material Adverse Effect. Buyer has no Knowledge of any facts or circumstances that make it reasonably likely that Buyer's Required Regulatory Approvals will not be obtained.

(b) Except as set forth in Schedule 5.3(b) (the filings and approvals referred to in such Schedule are collectively referred to as the "Buyer's Required Regulatory Approvals"), no declaration, filing or registration with, or notice to, or authorization, consent or approval of any Governmental Authority is necessary for the consummation by Buyer of the transactions contemplated hereby.

Section 5.4 Availability of Funds. Buyer and/or Buyer's Parent have sufficient funds available to it through corporate funds, credit facilities and access to capital markets to provide sufficient funds to pay the Purchase Price on the Closing Date and to enable Buyer timely to perform all of its obligations under this Agreement.

Section 5.5 Legal Proceedings. Except as set forth in Schedule 5.5, to the Knowledge of Buyer and Buyer's Parent, there are no claims, actions, proceedings or investigations pending or threatened against Buyer or Buyer's Parent before any court, arbitrator, mediator or Governmental Authority which, individually or in the aggregate, could reasonably be expected to (i) result in a Buyer Material Adverse Effect, (ii) prohibit or restrain the performance of this Agreement or any of the Ancillary Agreements or the consummation of the transactions contemplated hereby or thereby, or (iii) result in a material claim against Seller for damages as a result of Buyer or Buyer's Parent entering into this Agreement or any of the Ancillary Agreements, or of the consummation of the transactions contemplated hereby or thereby. Except as set forth in Schedule 5.5, neither Buyer's Parent nor Buyer is subject to any outstanding judgments, rules, orders, writs, injunctions or decrees of any court, arbitrator or Governmental Authority which, individually or in the aggregate, could reasonably be expected to have a Buyer Material Adverse Effect.

Section 5.6 WARN Act. Buyer does not intend with respect to the Purchased Assets to engage in a "plant closing" or "mass layoff," as such terms are defined in the WARN Act within sixty (60) days after the Closing Date.

Section 5.7 Transfer of Decommissioning Funds. With respect to Seller's transfer of the assets of the Qualified Decommissioning Fund to the Trustee under the Post-Closing Decommissioning Trust Agreement, except for the fact that Ginna in the hands of Buyer may not be treated as a "nuclear power plant" within the meaning of Treasury Regulations Section 1.468A-1(b)(4), Buyer will otherwise acquire and own a "qualifying interest" in Ginna within the meaning of Treasury Regulations Section 1.468A-1 and will, as the transferee, satisfy each of the requirements set forth in

Treasury Regulations Section 1.468A-6(b)(2). The Post-Closing Decommissioning Trust Agreement satisfies the requirements of Section 468A of the Code and the regulations promulgated thereunder.

Section 5.8 Foreign Ownership or Control. Buyer or, if applicable, Buyer's Parent, will conform to the restrictions on foreign ownership, control or domination contained in Sections 103d and 104d of the Atomic Energy Act of 1954, as amended, 42 U.S.C. §§ 2133(d) and 2134(d), as applicable, and the NRC's regulations in 10 C.F.R. § 50.38. Neither Buyer's Parent nor Buyer is currently owned, controlled or dominated by a foreign entity and neither will become owned, controlled, or dominated by a foreign entity before the Closing Date of this transaction.

Section 5.9 Seller's Representations and Warranties. As of the date hereof, neither Buyer nor Buyer's Parent has any Knowledge of any breaches of any of Seller's representations or warranties.

Section 5.10 Permit Qualifications. To the Knowledge of Buyer, Buyer (or its successor or assigns) will be as the owner of Ginna qualified to hold any Permits and Environmental Permits necessary to operate the Purchased Assets.

ARTICLE 6

COVENANTS OF THE PARTIES

Section 6.1 Conduct of Business Relating to the Purchased Assets.

(a) Except as described in Schedule 6.1(a) or to the extent Buyer otherwise consents in writing, during the period from the date hereof to the Closing Date, Seller (1) shall operate and maintain the Purchased Assets in the ordinary course consistent with Good Utility Practices; it being understood that any actions deemed reasonably necessary in the operation of the Purchased Assets in accordance with Good Utility Practices shall be deemed to be in the ordinary course unless such actions materially impair the value, rated capacity, ability to complete the Uprate or operation of the Purchased Assets or the liabilities and obligations of Buyer after the Closing Date, and that the Capital Budget is consistent with this standard; (2) shall use Commercially Reasonable Efforts to preserve intact the Purchased Assets and preserve the goodwill and relationships with customers, suppliers and others having business dealings with them with respect thereto; (3) shall maintain in full force and effect the insurance coverages described in Section 4.9; (4) shall comply in all material respects with all applicable Laws relating to the Purchased Assets, including without limitation, all Nuclear Laws and Environmental Laws; (5) shall maintain the Business Books and Records in the usual, regular and ordinary manner; (6) shall use its Commercially Reasonable Efforts to complete in accordance with Good Utility Practices, and in conformity with all applicable Laws, the Capital Expenditures set forth in Schedule 6.1(a) which are targeted for completion prior to the Closing Date; provided, however, in the case of (A) the submission of a purchase order for a new fuel design for the new fuel assemblies for the Uprate, such item shall be completed by Seller prior to January 30, 2004 and (B) active vehicle barriers and containment sump design upgrade, Seller shall have taken all reasonable steps necessary to permit timely completion of such items such that Buyer is not materially prejudiced thereby; (7) shall, and Seller shall continue after the Closing Date to, use its Commercially Reasonable Efforts to obtain an amendment of the Cooling Tunnel Easement extending the term thereof through December 31, 2029 (the "Cooling Tunnel Easement Amendment"), from the Office of General Services of the State of New York, which amendment shall be in recordable form; and (8) shall use Commercially Reasonable Efforts to train the applicable number of Transferred Employees required by Law to fill the emergency response positions currently filled by RG&E Employees who are not Transferred Employees; provided, however, in the event the actions required by subsection (8) are not completed prior to the Closing Date, then Seller must provide the existing trained RG&E Employees (at Seller's sole cost and expense) to fill the emergency response positions for a maximum of 60 days after the Closing Date. Notwithstanding the foregoing, except as contemplated in this Agreement or as described in Schedule 6.1(a), or as required under applicable Law or by any Governmental Authority or by any NRC Commitments, prior to the Closing Date, without the written consent of Buyer, which consent shall not be unreasonably withheld, Seller will not with respect to the Purchased Assets:

(i) make any material change in the levels of Inventories customarily maintained by Seller with respect to the Purchased Assets, except for such changes as are consistent with Good Utility Practices;

(ii) except for Permitted Encumbrances, sell, lease (as lessor), pledge, mortgage, encumber, restrict, transfer or otherwise dispose of, or grant any right, or suffer to be imposed any Encumbrance with respect to, any of the Purchased Assets, other than assets used, consumed or replaced in the ordinary course of business consistent with Good Utility Practices;

(iii) materially amend, extend or voluntarily terminate prior to the expiration date thereof any of Seller's Agreements or the Real Property Agreements listed in Schedule 4.8 (or any other agreement to the extent any such extension or amendment thereof would require the agreement to be disclosed on Schedule 4.8 or 4.15(a)(i)) or any material Permit or Environmental Permit or waive any default by, or release, settle or compromise any claim against, any other party thereto, other than (a) in the ordinary course of business, to the extent consistent with Good Utility Practices, (b) with cause, to the extent consistent with Good Utility Practices, or (c) as may be required in connection with Seller's obligations to Buyer under this Agreement;

(iv) enter into any new commitment for the purchase of Nuclear Fuel unless (A) the aggregate payments under all such new commitments would not be expected to exceed $500,000 or (B) the commitment is terminable either (x) automatically on the Closing Date or (y) at the option of

Buyer at any time after the Closing Date without any penalty or cancellation charge;

(v) enter into any power sales agreement having a term that extends beyond June 30, 2004 or such other date that the Parties mutually agree to be the date on which the Closing is expected to occur;

(vi) amend in any material respect or cancel any property, liability or casualty insurance policies related thereto, or fail to maintain by self insurance or with financially responsible insurance companies insurance in such amounts and against such risks and losses as are customary for such assets and businesses;

(vii) enter into any individual requirements contract for goods or any commitment or contract for non-employment related services, in either case not addressed in clauses (i) through (vi) above, that will be delivered or provided after June 30, 2004 or such other date as the Parties mutually agree to be the date on which the Closing is expected to occur that exceeds $100,000 per annum, unless such commitment or contract is terminable by Seller (or after the Closing Date by Buyer) upon not more than 60 days notice without penalty or cancellation charge;

(viii) hire any new Ginna Employees (other than to replace any existing Ginna Employees who have resigned or been terminated and employees hired to perform the duties of Ginna Employees who are on disability leave), materially increase the aggregate wages and benefits payable to Ginna Employees or establish, adopt, enter into or amend the Benefit Plans to the extent applicable to Ginna Employees;

(ix) except as reasonably necessary to complete the integration process for its pending SAP conversion, change, in any material respect, its accounting methods or practices, credit practices or collection policies or any pricing, investment, financial reporting, inventory, allowance or Tax practice or policy to the extent such change would be binding on Buyer;

(x) enter into, amend, make waivers under or otherwise modify any real or personal property Tax agreement, treaty or settlement, or make any new or change any current, election with respect to Taxes affecting the Purchased Assets to the extent such change would be binding on Buyer;

(xi) fail to take commercially reasonable best efforts to pursue currently pending regulatory approvals relating to the Facilities;

(xii) knowingly engage in any practice, take any action, fail to take any action, or enter into any transaction through the Closing Date that will result or may reasonably be anticipated to result in any misrepresentation or breach of any warranty of Seller hereunder as of the Closing Date;

(xiii) *settle any claim or litigation that results in any obligation* imposed on the Facilities or the Purchased Assets that could reasonably be likely to continue past the Closing Date; and

(xiv) agree to enter into any of the transactions set forth in the foregoing paragraphs (i) through (xiii).

(b) The Parties shall establish, as soon as practicable after the execution of this Agreement, a committee (the "Transition Committee") comprised of at least four (4) persons, including two (2) persons designated by Seller and two (2) persons designated by Buyer. The Transition Committee shall remain in existence until the Closing Date and shall oversee and manage the transition process through the Closing Date. The Transition Committee will be kept fully apprised by Seller of all the Facilities' management and operating developments, including with respect to any pre-closing outage, any repairs to the Facilities and the Capital Expenditures. The Transition Committee shall have reasonable access to the management of Seller. The Transition Committee shall report to the senior management of Seller and Buyer. The Transition Committee shall have no authority to bind or make agreements on behalf of Seller or Buyer or to issue instructions to or direct or exercise authority over Seller or Buyer or any of their respective officers, employees, advisors or agents or to waive or modify any provision hereof.

(c) Between the date of this Agreement and the Closing Date, in the interest of cooperation between Seller and Buyer and to plan for and facilitate an orderly transition of ownership and operation of the Purchased Assets from Seller to Buyer and to permit informed action by Buyer regarding its rights pursuant to Section 6.1(a), the Parties agree that at the sole responsibility and expense of Buyer, and subject to compliance with all applicable NRC rules and regulations, Seller will permit designated Buyer Representatives ("Observers") of Buyer to observe all operations of Seller that relate to the Purchased Assets, and such observation will be permitted on a cooperative basis in the presence of personnel of Seller but not restricted to the normal business hours of Seller; provided, however, that such Observers and their actions shall not interfere with the operation of Ginna. Seller shall use Commercially Reasonable Efforts to provide to the Observers, at no cost to Buyer, interim furnished office space, utilities and HVAC at the Facilities reasonably necessary to allow Buyer to conduct its transition efforts through the Closing Date; provided that Buyer shall be responsible for all other costs relating thereto, including, without limitation telecommunications expenses and the cost of workers' compensation and employer's liability coverage, which will be maintained by Buyer for its employees.

(d) Buyer's representatives on the Transition Committee and/or the Observers may recommend or suggest to Seller that actions be taken or not be taken by Seller to improve or enhance the operation and maintenance of the Purchased Assets from the date hereof through the Closing Date; provided, however, that Seller will not be under any obligation to follow any such recommendations or suggestions and Seller shall be entitled, subject to this Agreement, to conduct its business in accordance with its own judgment and discretion. Buyer's Observers shall have no authority to bind or make agreements on behalf of Seller; to conduct discussions with or make representations to third parties on behalf of Seller; or to issue instructions to or direct or exercise authority over Seller or any of Seller's officers, employees, advisors or agents.

(e) Between the date hereof and the Closing Date, Seller agrees to meet with representatives of Buyer from time to time and allow Buyer to provide input as to the scheduling, scope, capital expenditures and other activities to be included in the 2005 refueling outage and Seller shall in good faith consider the foregoing and to the extent such requests are in accordance with all applicable Laws, Seller's NRC License and Good Utility Practices and Seller is in agreement with Buyer, Seller shall implement such requests such that the 2005 refueling outage planning would include the Buyer requested activities, it being understood that any such activities by Seller taken at the request of Buyer shall not constitute or result in a breach of this Agreement.

(f) Seller agrees that, except as required by its obligations as a public utility under sections 65 and 66 of the New York Public Service Law, Seller shall not take or cause to be taken any action to reduce the unforced capacity credit assigned by the New York Independent System Operator to the Facilities under regulations or policies in effect on the date hereof; provided, however, that the foregoing shall in no way restrict or prohibit Seller (a) from taking or causing to be taken any action in accordance with Good Utility Practice, (b) from taking or causing to be taken any action that generally affects Seller's generating facilities, or (c) from abstaining from any vote of the New York Independent System Operator or any committee or subcommittee thereof.

Section 6.2 Access to Information.

(a) In addition to the rights granted by Sections 6.1(b) and (d), between the date of this Agreement and the Closing Date, Seller will, during ordinary business hours and upon reasonable notice and subject to compliance with all applicable NRC rules and regulations (i) give Buyer and Buyer's Representatives reasonable access to all management personnel engaged in the operation of the Purchased Assets and all books, documents, records, plants, offices and other facilities and properties constituting the Purchased Assets; (ii) permit Buyer to make such reasonable inspections thereof as Buyer may reasonably request, other than Phase II environmental site assessments (which have been conducted prior to the date hereof); (iii) furnish Buyer with such financial and operating data and other information with respect to the Purchased Assets as Buyer may from time to time reasonably request; (iv) furnish Buyer a copy of each material report, schedule or other document filed or received by it since the date hereof with respect to the Purchased Assets with the SEC, NRC, FERC, NYPSC or any other Governmental Authority having jurisdiction over the Purchased Assets; provided, however, that (A) any such investigation shall be conducted in such a manner as not to interfere unreasonably with the operation of the Purchased Assets, (B) Seller shall not be required to take any action which would constitute a waiver of the attorney-client privilege, and (C) Seller need not supply Buyer with any information that Seller is legally prohibited from supplying. Seller will provide Buyer or Buyer's Representatives with access to the Transferred Employee Records that it has, but Seller shall not be required to provide access to other employee records or medical information unless required by law or specifically authorized by the affected employee. Notwithstanding anything in this Section 6.2 to the contrary, Seller will only furnish or provide such access to Transferred Employee Records and personnel and medical records as is permitted by law or required by legal process or subpoena (other than data concerning salaries and benefits, dates of birth, dates of hire and other information used to calculate pension benefits which shall be provided).

(b) Buyer and Seller acknowledge that all information furnished to or obtained by Buyer or Buyer's Representatives pursuant to this Section 6.2 shall be subject to the provisions of the Confidentiality Agreement and shall be treated as "Proprietary Information" (as defined in Section 1.1(130)).

(c) Following the Closing Date and subject to all applicable NRC rules and regulations, each Party and its respective Representatives shall have reasonable access to all of the Business Books and Records, including all Transferred Employee Records or other personnel and medical records required to be made available by Law, legal process or subpoena, in the possession of the other Party or Parties to the extent that such access may reasonably be required by such Party in connection with the Assumed Liabilities and Obligations or the Excluded Liabilities, or other matters relating to or affected by the operation of the Purchased Assets. Such access shall be afforded by the Party or Parties in possession of such books and records upon receipt of reasonable advance notice and during normal business hours. The Party or Parties exercising this right of access shall be solely responsible for any costs or expenses incurred by it or them pursuant to this Section 6.2(c). If the Party or Parties in possession of such books and records shall desire to dispose of any such books and records, such Party or Parties shall, prior to such disposition, give the other Party or Parties a reasonable opportunity at such other Party's or Parties' expense, to segregate and remove such books and records as such other Party or Parties may select. Notwithstanding the foregoing, the right of access to medical records and other confidential employee records shall be subject to all applicable legal requirements.

(d) Seller agrees (i) not to release any Person (other than Buyer) from any confidentiality agreement now existing with respect to the Purchased Assets, or waive or amend any provision thereof, (ii) to promptly after the Closing Date assign any rights arising under any such confidentiality agreement (to the extent assignable) to Buyer, and (iii) to request the destruction or return of all confidential information provided to any other Person who participated in the Ginna sale process and who executed a Confidentiality Agreement in connection therewith.

(e) Notwithstanding the terms of the Confidentiality Agreement and Section 6.2(b) above, the Parties agree that prior to the Closing Buyer may reveal or disclose Proprietary Information to any other Persons in connection with Buyer's financing and risk management of the Purchased Assets, and, to the extent that Seller consents, which consent shall not be unreasonably withheld, to existing and potential customers and suppliers, and to such Persons with whom Buyer expects it may have business dealings regarding the Purchased Assets from and after the Closing Date; provided, however, that all such Persons agree in writing to maintain the confidentiality of the Proprietary Information on substantially the same terms and conditions of the Confidentiality Agreement.

(f) Except as may be permitted in the Confidentiality Agreement or during the course of Buyer's due diligence investigation of the Purchased Assets prior to the date hereof, Buyer agrees that, prior to the Closing Date, it will not contact any vendors, suppliers, employees, or other contracting parties of Seller or Seller's Affiliates with respect to any aspect of the Purchased Assets or the transactions contemplated hereby, without the prior written consent of Seller, which consent shall not be unreasonably withheld.

(g) Upon Buyer's or Seller's (as the case may be) prior written approval (which approval shall not be unreasonably withheld or delayed), Seller or Buyer (as the case may be) may provide Proprietary Information of the other Party to the SEC, NRC, FERC, NYPSC or any other Governmental Authority having jurisdiction over the Purchased Assets or any stock exchange, as may be necessary to obtain Seller's Required Regulatory Approvals or Buyer's Required Regulatory Approvals, respectively, or to comply generally with any applicable Laws. The disclosing Party shall seek confidential treatment for the Proprietary Information provided to any such Governmental Authority and the disclosing Party shall notify the other Party as far in advance as practical of its intention to release to any Governmental Authority any such Proprietary Information.

(h) The Parties agree that the Confidentiality Agreement shall remain in place until the Closing Date. Thereafter, the Parties agree that any restrictions contained in the Confidentiality Agreement with respect to Buyer's disclosure of Proprietary Information shall terminate, other than with respect to the Proprietary Information of Seller that does not relate to the Purchased Assets. The Parties further agree that after the Closing Date, Seller shall keep confidential all Proprietary Information provided by Buyer or which Seller possesses with respect to the Purchased Assets, to the extent permitted by Law, and to the same extent and under the same conditions applicable to Buyer's obligations with respect to Seller's Proprietary Information as contained in the Confidentiality Agreement between the Parties, but without limitation as to duration.

Section 6.3 Expenses. (a) Except to the extent specifically provided herein, whether or not the transactions contemplated hereby are consummated, all costs and expenses incurred in connection with this Agreement and the transactions contemplated hereby, including the cost of legal, technical and financial consultants and the cost of filing for and prosecuting applications for Buyer's and Seller's

Required Regulatory Approvals, shall be borne by the Party incurring such costs and expenses.

(b) Buyer shall be responsible for all reasonable third party vendor costs and expenses incurred and relating to work performed with respect to the Purchased Assets at the request of the Buyer after the date hereof.

Section 6.4 Further Assurances; Cooperation.

(a) Subject to the terms and conditions of this Agreement, each of the Parties hereto will use Commercially Reasonable Efforts to take, or cause to be taken, all action, and to do, or cause to be done, all things necessary, proper or advisable under applicable Laws to consummate and make effective the sale, transfer conveyance and assignment of the Purchased Assets and the assignment of the Assumed Liabilities and Obligations or the exclusion of the Excluded Liabilities pursuant to this Agreement, including without limitation using Commercially Reasonable Efforts to ensure satisfaction of the conditions precedent to each Party's obligations hereunder, including, without limitation, all regulatory approvals. Notwithstanding anything in the previous sentence to the contrary, Seller and Buyer shall use Commercially Reasonable Efforts to obtain all Permits and Environmental Permits necessary for Buyer to acquire and operate the Purchased Assets. Neither Buyer nor Seller will, without the prior written consent of the other, advocate, take or fail to take any action which would reasonably be expected to prevent or materially impede, interfere with or delay the transactions contemplated by this Agreement or which could reasonably be expected to cause, or to contribute to causing, the other to receive less favorable regulatory treatment than that sought by the other. Buyer further agrees that prior to the Closing Date, neither it nor its Affiliates will enter into any other contract to acquire, nor acquire, electric generation facilities or uncommitted generation capacity if the proposed acquisition of such additional electric generation facilities or uncommitted generation capacity which would increase the market power attributable to Buyer in a manner materially adverse to approval of the transactions contemplated hereby or would otherwise prevent or materially interfere with the transactions contemplated by this Agreement.

(b) From time to time after the Closing Date, without further consideration, Seller will execute and deliver such documents to Buyer as Buyer may reasonably request, at Buyer's expense, in order to more effectively consummate the sale and purchase, including the transfer, conveyance and assignment, of the Purchased Assets or to more effectively vest in Buyer such title to the Purchased Assets (or such rights to use, with respect to Purchased Assets not owned by Seller), as is provided for in Section 4.7, subject to the Permitted Encumbrances. Seller shall cooperate with Buyer, at Buyer's expense, in Buyer's efforts to cure or remove any Permitted Encumbrances that Buyer reasonably deems objectionable. From time to time after the Closing Date, without further consideration, Buyer will, at its own expense, execute and deliver such documents to Seller as Seller may reasonably request in order to evidence Buyer's assumption of the Assumed Liabilities and Obligations.

(c) The Parties shall cooperate with each other to facilitate the transition of the information systems, computer applications and processing of data at the Facilities.

(d) To the extent that Seller's rights under any Seller's Agreement may not be assigned without the consent of another Person which consent has not been obtained, this Agreement shall not constitute an agreement to assign the same if an attempted assignment would constitute a breach thereof or be unlawful, and Seller, at its expense, shall use Commercially Reasonable Efforts to obtain any such required consent(s) as promptly as possible. Seller and Buyer agree that if any consent to an assignment of any Seller's Agreement shall not be obtained or if any attempted assignment would be ineffective or would impair Buyer's rights and obligations under the applicable Seller's Agreement so that Buyer would not in effect acquire the benefit of all such rights and obligations, Seller, to the maximum extent permitted by law and such Seller's Agreement, shall after the Closing appoint Buyer to be Seller's Representative and agent with respect to such Seller's Agreement, and Seller shall, to the maximum extent permitted by Law and such Seller's Agreement, enter into such reasonable arrangements with Buyer as are necessary to provide Buyer with the benefits and obligations of such Seller's Agreement (the cost of administering which shall be at Seller's expense). Seller and Buyer shall cooperate and shall each use Commercially Reasonable Efforts after the Closing to obtain an assignment of such Seller's Agreement to Buyer.

For a reasonable time after the Closing Date, Buyer and Seller agree to provide such services to each other as are reasonably required to the extent necessary to ensure the continuity of support for Ginna and the Seller's other facilities and the orderly completion of projects or other work in progress that would be adversely affected if those services were interrupted, including mutually acceptable arrangements regarding the lease of the emergency operations facilities from Seller to Buyer for a period of up to three years. Buyer and Seller will agree, as promptly as practicable, following the date hereof, on the nature of such services, which shall be agreed upon in service agreements and other agreements, as necessary, with the Seller or Buyer or their Affiliates. The Party providing the services will be reimbursed for all its costs, including development costs, in accordance with procedures to be mutually agreed upon by Seller and Buyer or on an alternative cost reimbursement basis as mutually agreed by Seller and Buyer. Notwithstanding anything to the contrary contained in this Agreement, the Parties agree and understand that Seller will not be providing transition services on or after the Closing Date to Buyer in the areas of human resources, payroll, accounts receivable, accounts payable and general ledger. Seller agrees to cooperate with Buyer and to reasonably assist Buyer in a safe and adequate transition with respect to the provision of these services by Buyer by the Closing Date; provided, however, that in the event Seller fails to provide to Buyer within a reasonable period of time prior to Closing the information, agreements (including, but not limited to, the Transferred Employee Records and the records required pursuant to Section 6.10(f)) and assistance Buyer reasonably needs in order to transition the areas of human resources, payroll, accounts receivable, accounts payable and general ledger, then Seller shall provide such transition services (at

Seller's sole cost and expense) for 90 days after Closing such that Buyer is able to transition such services.

Section 6.5 Public Statements. Until thirty (30) days following the Closing Date, the Parties shall not issue any press release or other public disclosure with respect to this Agreement or the transactions contemplated hereby without first affording the non-disclosing Party the opportunity to review and comment on such disclosure, except as may be required by applicable Laws or stock exchange rules.

Section 6.6 Consents and Approvals.

(a) Seller and Buyer shall each file or cause to be filed with the Federal Trade Commission and the Department of Justice any notifications required to be filed under the HSR Act and the rules and regulations promulgated thereunder with respect to the transactions contemplated hereby. The Parties shall consult with each other as to the appropriate time of filing such notifications and shall agree upon the timing of such filings, and respond promptly to any requests for additional information made by either of such agencies. The Parties shall use their Commercially Reasonable Efforts to cause the waiting periods under the HSR Act to terminate or expire at the earliest possible date after the date of filing. All filing fees under the HSR Act shall be borne 50% by the Seller and 50% by the Buyer and each Party will bear its own costs for the preparation of any such filing.

(b) As promptly as practicable after the date of this Agreement and after the receipt of any findings required to be made by any other Governmental Authority as a condition to Buyer and Seller making the filings contemplated by this paragraph, (i) Buyer shall file with FERC (and if requested by Buyer, Seller shall support) an application requesting Exempt Wholesale Generator status for Buyer, which filing may be made individually by Buyer or jointly with Seller, as reasonably determined by Buyer, (ii) Seller shall file, with Buyer's support, an application with FERC requesting approval of the Interconnection Agreement as an agreement grand-fathered from the effectiveness of the Final Rule interconnection agreement adopted in FERC Docket RM02-1-000 on July 24, 2003, and (iii) Buyer shall file with FERC any necessary applications requesting approval of the Power Purchase Agreement. In fulfilling their respective obligations set forth in the immediately preceding sentence, Buyer and Seller shall each use Commercially Reasonable Efforts to effect the referenced filings with FERC within thirty (30) days of the date of this Agreement. Prior to submitting such applications with FERC, the Party preparing the application shall submit the application to the other Party for review and comment, and the filing Party shall in good faith consider any revisions reasonably requested by the other Party. Each Party shall be solely responsible for its own cost of preparing, reviewing and filing its respective application, responses and any petition(s) for rehearing or any reapplication(s).

(c) As promptly as practicable after the date of this Agreement, Buyer and Seller shall file with NYPSC a Petition for approval of the sale of the Purchased Assets under Section 70 of the New York Public Service Law or Buyer shall join in the Section 70 Petition Seller has already filed and such Petition shall be amended accordingly. As promptly as practicable after the date of this Agreement, Seller shall file with the NYPSC the Power Purchase Agreement under Section 110 of the New York Public Service Law and Buyer shall file with the NYPSC and any other applicable state Governmental Authority having jurisdiction over Buyer or the Purchased Assets, an application requesting a determination that allowing the Purchased Assets to be an eligible facility under Section 32 of the Holding Company Act, (i) will benefit consumers, (ii) is in the public interest, and (iii) does not violate state law. In fulfilling their respective obligations set forth in the immediately preceding two sentences, Buyer and Seller shall each use Commercially Reasonable Efforts to effect or cause to be effected any such filings within thirty (30) days of the date of this Agreement. Prior to any Party's submission of the applications contemplated by this Section 6.6(c), the submitting Party shall give such application to the other Parties for review and comment and the submitting Party shall in good faith consider any revisions reasonably requested by the reviewing Parties. Each Party will bear its own costs of the preparation and review of any such filings.

(d) As promptly as practicable after the date of this Agreement, Buyer shall file with FERC an application requesting authorization under Section 205 of the Federal Power Act to sell electric generating capacity and energy (and, at Buyer's discretion, other services, including, without limitation, ancillary services) at wholesale at market-based rates. In fulfilling its obligations set forth in the immediately preceding sentence, Buyer shall use its Commercially Reasonable Efforts to file the referenced application with FERC within thirty (30) days of the date of this Agreement. Prior to Buyer's submission of such application with FERC, Buyer shall submit such application to Seller for review and comment and Buyer shall consider any revisions reasonably requested by Seller. Buyer shall be solely responsible for the cost of preparing and filing this application, any petition(s) for rehearing, or any reapplication(s). Each Party will bear its own costs of the preparation and review of any such filings.

(e) As promptly as practicable after the date of this Agreement, Buyer and Seller shall file with NRC an application requesting consent under Section 184 of the Atomic Energy Act and 10 C.F.R. § 50.80 for the transfer of the NRC License from Seller to Buyer, and approval of any conforming license amendments or other related approvals. In fulfilling their respective obligations set forth in the immediately preceding sentence, each of Buyer and Seller shall use its Commercially Reasonable Efforts to effect any such filing within thirty (30) days of the date of this Agreement. Each Party will bear its own costs of the preparation of any such filing and NRC fees shall be borne 50% by Buyer and 50% by Seller. Thereafter, Buyer and Seller shall cooperate with one another to facilitate NRC review of the application by providing the NRC staff with such documents or information that the NRC staff may reasonably request or require any of the Parties to provide or generate.

(f) Seller and Buyer shall cooperate with each other and promptly prepare and file notifications with, and request Tax clearances from, state and local taxing authorities in jurisdictions in which a portion of the Purchase Price may be required to be withheld or in which Buyer would otherwise be liable for any Tax liabilities of Seller pursuant to such state and local Tax law.

(g) As promptly as practicable after the date of this Agreement, but no later than thirty (30) days after Buyer supplies to Seller all of the information regarding Buyer that is required to be included in the application described in this Section 6.6(g), Seller and Buyer shall jointly prepare as co-applicants, and Seller shall file with FERC, an application for approval of this transaction under Section 203 of the Federal Power Act. In fulfilling their respective obligations set forth in this Section 6.6(g), Seller and Buyer shall use their Commercially Reasonable Efforts. Prior to Seller's submission of such application with FERC, Seller shall submit such application to Buyer for review and comment and Seller shall consider any revisions reasonably requested by Buyer. Seller and Buyer shall respond promptly to all requests from FERC or its staff for additional information regarding such application. Seller shall be solely responsible for the cost of filing this application, any petition(s) for rehearing, or any reapplication(s). Each Party will bear its own costs of the review of such filings.

(h) Seller and Buyer shall cooperate with each other and, as promptly as practicable after the date of this Agreement, (i) prepare and make with FERC, NYPSC or any other Governmental Authority having jurisdiction over Seller, Buyer or the Purchased Assets, all necessary filings required to be made with respect to the transactions contemplated hereby (including those specified above), (ii) effect all necessary applications, notices, petitions and filings and execute all agreements and documents, (iii) use Commercially Reasonable Efforts to obtain the transfer or reissuance to Buyer of all necessary Permits, Environmental Permits, consents, approvals and authorizations of all Governmental Authorities, and (iv) use Commercially Reasonable Efforts to obtain all necessary consents, approvals and authorizations of all other parties, in the case of each of the foregoing clauses (i), (ii) and (iii), necessary or advisable to consummate the transactions contemplated by this Agreement (including, without limitation, Seller's Required Regulatory Approvals and Buyer's Required Regulatory Approvals) or required by the terms of any note, bond, mortgage, indenture, deed of trust, license, franchise, permit, concession, contract, lease or other instrument to which Seller or Buyer is a party or by which any of them is bound. The Parties shall respond promptly to any requests for additional information made by such agencies, and use their respective Commercially Reasonable Efforts to cause regulatory approval to be obtained at the earliest possible date after the date of filing. Each Party will bear its own costs of the preparation and review of any such filing. Seller and Buyer shall have the right to review in advance all characterizations of the information relating to the transactions contemplated by this Agreement which appear in any filing made in connection with the transactions contemplated hereby and the filing Party shall consider in good faith any revisions reasonably requested by the non-filing Party.

(i) Buyer shall have the primary responsibility for securing the transfer, reissuance or procurement of the Permits and Environmental Permits (other than Transferable Permits) effective as of the Closing Date. Seller shall cooperate with

Buyer's efforts in this regard and assist in any transfer or reissuance of a Permit or Environmental Permit held by Seller or the procurement of any other Permit or Environmental Permit when so requested by Buyer. In the event that Buyer is unable, despite its Commercially Reasonable Efforts, to obtain a transfer or reissuance of one or more of the Permits or Environmental Permits as of the Closing Date, Buyer may use the applicable Permit or Environmental Permit issued to Seller, provided (i) such use is not unlawful, (ii) Buyer notifies Seller prior to the Closing Date, (iii) Buyer continues to make Commercially Reasonable Efforts to obtain a transfer or reissuance of such Permit or Environmental Permit after the Closing Date, and (iv) Buyer indemnifies Seller for any losses, claims or penalties suffered by Seller in connection with the Permit or Environmental Permit that is not transferred or reissued as of the Closing Date resulting from Buyer's ownership or operation of the Purchased Assets following the Closing Date. In no event shall Buyer use or otherwise rely on a Permit or Environmental Permit issued to Seller beyond one year after the Closing Date.

Section 6.7 Brokerage Fees and Commissions. Seller and Buyer each represent and warrant to the other that, other than with respect to fees and commissions of J.P. Morgan Securities Inc. and Concentric Energy Advisors Inc., which shall be the sole responsibility of Seller, no broker, finder or other Person is entitled to any brokerage fees, commissions or finder's fees in connection with the transaction contemplated hereby by reason of any action taken by the Party making such representation. Seller and Buyer will pay to the other or otherwise discharge, and will indemnify and hold the other harmless from and against, any and all claims or liabilities for all brokerage fees, commissions and finder's fees incurred by reason of any action taken by the indemnifying party.

Section 6.8 Tax Matters.

(a) All Transfer Taxes incurred in connection with this Agreement and the transactions contemplated hereby shall be borne by Buyer. Buyer will file, to the extent required by applicable Law, all necessary Tax Returns and other documentation with respect to all such Transfer Taxes, and Seller will be entitled to review such returns in advance and, if required by applicable Law, will join in the execution of any such Tax Returns or other documentation. Prior to the Closing Date, Buyer will provide to Seller, to the extent possible, an appropriate exemption certificate in connection with this Agreement and the transactions contemplated hereby, due from each applicable taxing authority.

(b) With respect to Taxes to be prorated in accordance with Section 3.5 of this Agreement, Buyer shall prepare and timely file all Tax Returns required to be filed after the Closing with respect to the Purchased Assets, if any, and shall duly and timely pay all such Taxes shown to be due on such Tax Returns. Buyer's preparation of any such Tax Returns shall be subject to Seller's approval to the extent that such Returns relate to any period, allocation or other amount for which the Seller is responsible, which approval shall not be unreasonably withheld. Buyer shall make such Tax Returns and all schedules and working papers supporting such Tax Returns available for Seller's review and approval no later than fifteen (15) Business Days prior to the due date for filing such Tax Return. Subject to Section 6.8(d), not less than five (5) Business Days prior to the due date of any such Tax Return, Seller shall pay to Buyer a portion of the amount shown as due on such Tax Return as determined in accordance with Section 3.5 of this Agreement. In the event Buyer and Seller cannot agree as to the preparation or the reporting of any material item on a Tax Return to be filed by Buyer, the dispute shall be settled in the manner provided by Section 6.8(d) hereof and the cost of such Independent Accounting Firm shall be borne equally by the Parties.

(c) With respect to Seller's Qualified Decommissioning Fund, prior to the Closing Date, the Trustee will cause the Qualified Decommissioning Fund to pay estimated Income Taxes for the taxable period that ends on the Closing Date in an amount equal to the estimated Income Tax Liability of Seller's Qualified Decommissioning Fund for the taxable period that ends on the Closing Date. To the extent the amount of estimated Income Taxes paid pursuant to this section is in excess of the Income Tax Liability of Seller's Qualified Decommissioning Fund for the taxable period that ends on the Closing Date, any such refund will be forwarded to, and deposited in, the Buyer's Qualified Decommissioning Fund. To the extent the amount of estimated Income Taxes paid pursuant to this section is less than the Income Tax Liability of Seller's Qualified Decommissioning Fund for the taxable period that ends on the Closing Date, any such deficiency will be paid by, and from Buyer's Qualified Decommissioning Fund.

(d) Each of the Parties shall provide the other with such assistance as may reasonably be requested by the other Party in connection with the preparation of any Tax Return, any audit or other examination by any taxing authority, or any judicial or administrative proceedings relating to Liability for Taxes, and each will retain and provide the requesting Party with any records or information which may be relevant to such return, audit or examination, proceedings or determination. Any information obtained pursuant to this Section 6.8(d) or pursuant to any other Section hereof providing for the sharing of information or review of any Tax Return or other schedule relating to Taxes shall be kept confidential by the Parties hereto, except to the extent such information is required to be disclosed by Law. Notwithstanding the preceding sentence, each Party to this transaction (and each employee, representative or agent of any taxpayer) may disclose to any and all Persons, without limitations of any kind, the "structures" and "tax aspects" (as such terms are used in Sections 6011, 6012 and 6112 of the Code and the regulations promulgated thereunder) of the transactions and all materials of any kind (including opinions and other tax analyses) that are provided to the Party relating to such "structures" or "tax aspects", and no Party is subject to any restriction concerning its consulting with its tax adviser regarding the "structure" or "tax aspects" of this transaction at any time. Each Party intends that this transaction will not constitute a "confidential transaction" under the Code or the regulations promulgated thereunder.

(e) In the event that a dispute arises between Seller and Buyer as to the preparation or the reporting of any material item on a Tax Return to be filed by Buyer or the allocation of such Taxes between Seller and Buyer, the Parties shall attempt in good faith to resolve such dispute, and any agreed amount shall be paid to the appropriate Party within ten (10) Business Days of the date on which the Parties reach agreement. If a dispute is not resolved within thirty (30) days, the Parties shall submit the dispute to the Independent Accounting Firm for resolution, which resolution shall be final, conclusive and binding on the Parties. Notwithstanding anything in this Agreement to the contrary, the fees and expenses of the Independent Accounting Firm in resolving the dispute shall be borne fifty percent (50%) by Seller and fifty percent (50%) by Buyer. Any payment required to be made as a result of the resolution of the dispute by the Independent Accounting Firm shall be made within ten (10) days after such resolution, together with any interest determined by the Independent Accounting Firm to be appropriate. Submission of a dispute to the Independent Accounting Firm shall not relieve any Party from any obligation under this Agreement to timely file a Tax Return or pay a Tax.

Section 6.9 Advice of Changes. Prior to the Closing Date, each Party will promptly advise the other in writing of any change or discovery occurring after the date hereof that would constitute a material breach of any representation, warranty or covenant of the advising or other Party under this Agreement. If a Party advises the other Party of any such matter with respect to a material breach of the advising Party, the other Party shall have the right to terminate this Agreement in accordance with Sections 9.1(e) or (f) as the case may be. If a Party advises the other Party of any such matter with respect to a material breach by the other Party, the advising Party shall have the right to terminate this Agreement in accordance with Sections 9.1(e) or (f) as the case may be. If a Party fails to exercise its termination right, the written notice under this Section 6.9 will be deemed to have amended this Agreement, including the appropriate schedule, or to have qualified the representations and warranties contained in Articles 4 and 5. Seller shall be entitled to amend, substitute or otherwise modify any Seller's Agreement to the extent that such Seller's Agreement expires by its terms prior to the Closing Date or is terminable without Liability to Buyer on or after the Closing Date (other than an amendment that would extend the term thereof for a new term of years in excess of the then current term), or if the terms and conditions of such modified Seller's Agreement constituting the Assumed Liabilities and Obligations are on terms and conditions not less favorable to Buyer than the original Seller's Agreement.

Section 6.10 Employees.

(a) Buyer or a directly or indirectly wholly owned Subsidiary of Buyer will offer employment, commencing as of the Closing Date, to all Ginna Employees employed as of the Closing Date, which Ginna Employees are set forth on Schedule 6.10(a), as amended between the date of this Agreement and the Closing Date to reflect any changes in the identities of work force personnel.

(b) Each Ginna Employee who is offered and accepts continued employment with Buyer will be referred to herein as a "Transferred Employee."

(c) For the period commencing on the Closing Date and ending eighteen (18) months thereafter, and except as Buyer and any Transferred Employee may otherwise mutually agree, Buyer shall provide each Transferred Employee with total compensation including without limitation base pay, authorized overtime, bonuses, incentive compensation and benefits provided under all applicable employee benefits plans and programs, and fringe benefit arrangements (other than each of the Performance Plans relating to the Ginna divestiture and the severance agreements listed on Schedule 6.10(o) hereto) (collectively, "Total Compensation") which in the aggregate is comparable in value and nature to the Transferred Employee's annualized Total Compensation received from Seller immediately prior to Closing. Buyer shall also: (i) pay the reasonable relocation costs of any Transferred Employee who shall relocate at Buyer's request during such 18 month period and (ii) maintain the defined benefit plan described in Section 6.10(h) for the period specified in that Section. Seller shall fully vest or shall cause to be fully vested no later than the Closing Date any benefit accrued by Transferred Employees or granted by Seller to Transferred Employees under the Non-Qualified Top-Hat Plans listed in Schedule 4.12(a) other than the Energy East Corporation 2000 Stock Option Plan and the Energy East Corporation Restricted Stock Plan. Buyer shall provide top-hat, non-qualified and equity benefits to Transferred Employees that Buyer determines are eligible under Buyer's applicable plans.

(d) As of the Closing Date, all Transferred Employees shall cease to participate in the employee welfare benefit plans (as such term is defined in ERISA) maintained or sponsored by Seller or its Affiliates and shall commence participation (if applicable eligibility requirements are satisfied) in the employee welfare benefit plans of Buyer or its Affiliates (the "Replacement Welfare Plans") that for Transferred Employees will provide benefits and coverage that are comparable in the aggregate to the benefits and coverage provided to the Transferred Employees in the aggregate under Seller's, or its Affiliate's, as the case may be, welfare benefit plans in effect for the Transferred Employees immediately prior to the Closing Date. Buyer shall (i) waive all limitations as to pre-existing condition exclusions and waiting periods with respect to the Transferred Employees under the Replacement Welfare Plans, other than, but only to the extent of, limitations or waiting periods that were in effect with respect to such employees under the welfare plans maintained by Seller or its Affiliates and that have not been satisfied as of the Closing Date, and (ii) provide each Transferred Employee with credit for any co-payments and deductibles paid prior to the Closing Date during a plan year under Seller's or its Affiliates' plans that have not ended as of the Closing Date, in satisfying any deductible or out-of-pocket requirements under the Replacement Welfare Plans (on a pro-rata basis in the event of a difference in plan years).

(e) Buyer shall give all Transferred Employees credit for all service with Seller and its Affiliates under all employee welfare benefit plans and arrangements and all fringe benefit plans, programs, and arrangements of Buyer ("Replacement Benefit Plans") in which they become participants. The service credit given is for purposes of eligibility, vesting and service related level of benefits, but not benefit accrual (except as provided in the following sentence). For purposes of benefit accrual, Buyer shall give Transferred Employees credit for all service with Seller and its Affiliates under all Replacement Benefit Plans, but the ultimate benefits provided under Replacement Benefit Plans may be offset by the corresponding benefits previously provided by Seller or its Affiliates or benefit plans of Seller or its Affiliates, or by the corresponding benefits accrued under the benefit plans of Seller or its Affiliates or otherwise committed to be provided by Seller or its Affiliates in the future; provided, however, that such an offset shall not be permitted with respect to the Replacement Defined Benefit Plan described in Section 6.10(h).

(f) Not less than four (4) weeks prior to the Closing Date, Seller shall provide Buyer with such pertinent data or information as Buyer shall reasonably require to comply with Sections 6.10 (c), (d), (e), (h), (l) and (m) including each Transferred Employee's service, accrued but unused paid time off, satisfaction of limitations or waiting periods, amounts of co-payments and deductibles, accrued benefits available for offset under Section 6.10(e), each as of the Closing Date, as well as such other information as Buyer shall reasonably request for such purpose. To the extent the consent of a Transferred Employee is required in order for Seller to deliver any such pertinent data or information, Seller agrees to secure such consent. In the event that Seller is unable to obtain such consent, Buyer may treat the refusal of consent as declination of its employment offer and such employees shall be treated as if they had never accepted the employment offer of Buyer and shall not be entitled to any severance or other benefits to be provided to Transferred Employees hereunder. Seller agrees to provide Buyer not less than four (4) weeks prior to the Closing Date with a list of Ginna Employee participants in each non-qualified or supplemental Benefit Plan, and also to disclose any outstanding Ginna Employee equity grants.

(g) Buyer agrees to allow the Transferred Employees, as of the Closing Date, to be eligible to commence participation in a tax-qualified 401(k) plan sponsored by Buyer or its Affiliates that will provide benefits which in the aggregate are comparable in value and nature to the benefits provided to the Transferred Employees under the tax-qualified 401(k) plan sponsored by the Seller or its Affiliates in effect for Transferred Employees immediately prior to the Closing Date ("RG&E Savings Plan").

To the extent allowable by law and by the applicable Seller plan, Buyer shall take any and all necessary action to cause the trustee of any tax-qualified 401(k) plan of Buyer or its Affiliates in which any Transferred Employee becomes a participant to accept a direct "rollover" in cash of all or a portion of said employee's "eligible rollover distribution" within the meaning of Section 402 of the Code from the RG&E Savings Plan if requested to do so by the Transferred Employee. However, any tax-qualified 401(k) plan of Buyer or its Affiliates accepting such a rollover shall not be required to permit any investment to be made in Energy East Corporation common stock on behalf of any Transferred Employee after the Closing Date. Notwithstanding anything in this paragraph to the contrary, if Transferred Employees are not entitled to distributions from the RG&E Savings Plan as a result of being employed by Buyer, then either (i) the parties may negotiate a direct transfer from the RG&E Savings Plan trust to Buyer's tax-qualified plan trust under such terms and conditions as are agreeable to both parties or (ii) if the parties are unable to negotiate such an agreement, then Buyer agrees to provide Seller, in a timely manner, with such information as Seller reasonably needs about the Transferred Employees in order for Seller to administer the Transferred Employees' benefits under the RG&E Savings Plan (e.g., information about when the Transferred Employees retire, die, terminate employment).

(h) Effective as of the Closing Date, Buyer shall cause to be provided a defined benefit pension plan for the benefit of the Transferred Employees ("Replacement Defined Benefit Plan"). The Replacement Defined Benefit Plan shall provide benefit formulas that are identical to the benefit plan formulas in Article IV of the Rochester Gas and Electric Corporation Retirement Plan ("RG&E Defined Benefit Plan") as of the Closing Date. For the purposes of this Section 6.10(h), except as required by Law or as required by the IRS in connection with Seller's application for a determination letter for the RG&E Defined Benefit Plan, no improvements shall be made to such benefit formulas referenced above in the RG&E Defined Benefit Plan for the Transferred Employees after the date hereof and prior to the Closing Date without the written consent of Buyer, which consent shall not be unreasonably withheld. Buyer agrees to maintain such benefit formulas for Transferred Employees for a period of at least eighteen (18) months after the Closing Date (and for an additional period of at least thirty-six (36) months after the end of such eighteen (18) month period, Buyer agrees to provide benefit formulas that are identical to the benefit plan formulas in Sections 4.1 through 4.11 and Sections 4.13 through 4.15 of the RG&E Defined Benefit Plan (as such formulas are in effect on the Closing Date)), (provided, however, that if changes in the Law require any such terms to be modified or if any such terms are required by the IRS to be modified in connection with Buyer's application for a determination letter for the Replacement Defined Benefit Plan, Buyer may modify such terms to the extent necessary to comply with such laws).

The Transferred Employees shall be given credit in the Replacement Defined Benefit Plan for all service with and compensation from Seller and its Affiliates as if it were service with and compensation from Buyer for purposes of determining eligibility for benefits, the amount of any benefits or benefit accruals, vesting and service related levels of benefits under the Replacement Defined Benefit Plan.

At least thirty (30) days prior to the Closing Date, Seller and Buyer shall file or cause to be filed any forms 5310-A that may be required to be submitted to the IRS in connection with the transfers described in this Section 6.10(h). The transfers and payments described in this Section 6.10(h) shall in no event be made prior to the thirtieth (30^{th}) day following the filing of such form 5310-A with the IRS. In the event that the IRS, the PBGC or any other Governmental Authority raises any objections to the transfer, the Seller and Buyer shall cooperate in good faith to resolve any such objections.

On the Closing Date, the Seller shall cause to be transferred from the RG&E Defined Benefit Plan to the corresponding Replacement Defined Benefit Plan, assets equal to Seller's good faith estimate of the amount that Seller is permitted to transfer in compliance with the requirements of Section 414(l) of the Code and Treasury Regulation Section 1.414(l)-1 (determined under assumptions used by the PBGC as of the Closing Date) multiplied by .80 (the "Initial Transfer").

Within sixty (60) days after the Closing Date, Seller shall calculate the actual amount that Seller is permitted to transfer in compliance with the requirements of Section 414(l) of the Code and Treasury Regulation Section 1.414(l)-1 (determined under assumptions used by the PBGC as of the Closing Date) (the "Actual Amount"). To the extent that the Actual Amount is less than the Initial Transfer, the amount of such differential (including any applicable interest determined in good faith by Buyer) shall be transferred by the Replacement Defined Benefit Plan to the RG&E Defined Benefit Plan. To the extent that the Actual Amount is greater than the Initial Transfer, the Seller shall cause to be transferred from the RG&E Defined Benefit Plan to the Replacement Defined Benefit Plan the amount of such differential (including any applicable interest determined in good faith by Seller).

To the extent that the Actual Amount is less than Thirty Million Dollars ($30,000,000.00), the Purchase Price shall be decreased by the amount of the shortfall. To the extent that the Actual Amount is greater than Thirty Million Dollars ($30,000,000.00), the Purchase Price shall be increased by the amount of the differential.

All assets transferred and payments made under this Section 6.10(h) shall be made in cash, or in marketable securities that are reasonably acceptable to Buyer.

Upon completion of the Initial Transfer under this Section 6.10(h), all benefit payments from the Replacement Defined Benefit Plan shall be the responsibility of Buyer.

In the event that the Closing occurs after June 30, 2004, the Purchase Price shall be decreased by the amount of One Hundred Seventy-Five Thousand Dollars ($175,000.00) per month in each of July, August and September, 2004, prorated to the Closing Date; provided that if the Closing occurs on or after October 1, 2004, the total decrease in the Purchase Price shall be Five Hundred Twenty-Five Thousand Dollars ($525,000.00).

(i) Buyer and Seller do not anticipate the issuance of any notices pursuant to the WARN Act. Notwithstanding the foregoing, Seller agrees to timely perform and discharge all requirements under the WARN Act and under applicable state and local laws and regulations for the notification of employees arising from the sale of the Purchased Assets to Buyer up to the Closing Date for those employees who will not become Transferred Employees effective as of the Closing Date. On or after the Closing Date, Buyer shall be responsible for performing and discharging all requirements under the WARN Act and under applicable state and local laws and regulations for the notification of Transferred Employees with respect to the Purchased Assets. At Closing, Seller shall provide to Buyer a certificate setting forth the number of employees, if any, who suffered an "employment loss," as defined under the WARN Act, at the Purchase Assets in the ninety (90) days immediately preceding the Closing Date (the "WARN Certificate").

(j) Seller is responsible for extending COBRA continuation coverage to all employees and former employees, and qualified beneficiaries of such employees and former employees, who become or became entitled to such COBRA continuation coverage on or before the Closing Date by reason of the occurrence of a qualifying event on or before the Closing Date, including those for whom the Closing Date occurs during their COBRA election period. Buyer shall be responsible for providing COBRA continuation coverage only to Transferred Employees and qualified beneficiaries of such employees who become entitled to such COBRA continuation coverage on or after the Closing Date by reason of the occurrence of a qualifying event after the Closing Date.

(k) Seller shall remain responsible for paying Transferred Employees for: (a) all salary, wages, and Benefit Plan benefits (excluding to the extent provided in Sections 6.10(h) and 6.10(o)), a pro rata portion of any bonuses or incentive compensation that were earned for time worked for Seller or Seller's Affiliates prior to the Closing Date; and (b) all workers' compensation, disability benefits, or other insurance benefits for which entitlement to payment is based upon events occurring prior to the Closing Date including any incurred but unreported claims under the Benefit Plans. Seller shall pay to Buyer as set forth in Section 3.3, the cash equivalent for all vacation time, floating holidays, sick days, personal days (including, but not limited to, those related to the Personal Day Program of Seller) and bonuses and incentive compensation for Transferred Employees which have accrued as of the Closing Date (holiday time shall not be included in such payment). For purposes hereof, the foregoing calculations shall be determined consistent with Seller's past practices.

(l) Individuals who are otherwise "Transferred Employees" but who on the Closing Date are not actively at work due to a leave of absence covered by the Family and Medical Leave Act or similar state or local Law, or due to any other authorized leave of absence, shall nevertheless be treated as "Transferred Employees" but only if he or she is able to (i) return to work within the protected period under the Family and Medical Leave Act or similar state or local Law, or, in the case of any other type of authorized leave, within the period established by Buyer in Buyer's reasonable discretion, and (ii) perform the essential functions of their job, with or without a reasonable accommodation.

(m) For at least eighteen (18) months following the Closing Date, Buyer shall provide all Transferred Employees with retiree medical, mental health, prescription drug, and life insurance coverages (the "Replacement Retiree Coverages") that are in the aggregate comparable in value and nature to the Seller's retiree medical, mental health, prescription drug, and life insurance coverages available to eligible Ginna Employees who retire from Seller immediately prior to the Closing Date (the "RG&E Retiree Coverages"). Buyer shall (i) waive all limitations as to pre-existing condition exclusions and waiting periods with respect to the Transferred Employees under the Replacement Retiree Coverages, other than, but only to the extent of limitations or waiting periods that were in effect with respect to such employees under the RG&E Retiree Coverages and that have not been satisfied as of the Closing Date, and (ii) provide each Transferred Employee with credit for any co-payments and deductibles paid prior to the Closing Date during a plan year under each applicable Seller's plan that has not ended as of the Closing Date, in satisfying any deductible or out-of-pocket requirements under the Replacement Retiree Coverages (on a pro-rata basis in the event of a difference in plan years). Effective as of the Closing Date, Seller shall have no responsibility to provide retiree medical, mental health, prescription drug or life insurance coverages for any Transferred Employee.

(n) Buyer shall pay to each Transferred Employee whose employment is terminated without cause by Buyer or one of its Affiliates within eighteen (18) months of the Closing Date a severance benefit package equal to or greater than the following:

- Severance Pay: A lump sum equal to two (2) weeks of base pay for each full year of service (including service with both Buyer and Seller), less applicable taxes and withholdings.
- Transition Allowance: $7,500, less applicable taxes and withholdings.
- Insurance Benefits: Health and Life Insurance comparable to coverage received by retirees (who were employed by Seller on or after January 1, 1983) on the Closing Date for one (1) year from the date of termination.
- EAP Benefits: Benefits in accordance with the provisions of the Seller's Employee Assistance Program for one (1) year.
- Outplacement Benefits: Employer paid retraining and/or outplacement allowance of up to $5,000, less applicable taxes and withholdings, for twelve (12) months after termination.

For purposes of calculating the level of any of the foregoing severance benefits to which a terminated Transferred Employee is entitled, such calculation shall be made as though the Transferred Employee's termination date is the eighteenth (18th) month anniversary of the Closing Date, regardless of the actual date of termination. A Transferred Employee's entitlement to the foregoing severance benefits shall be contingent on the Transferred Employee's execution of an agreement releasing Buyer, Seller and their respective Affiliates from any legal claims. Nothing contained herein shall alter the at-will employment relationship of any Transferred Employee.

(o) Notwithstanding any other provision of this Agreement, Buyer shall assume the Liabilities for the obligations of Seller under the Performance Plans relating to Ginna Divestiture listed on Schedule 6.10(o) hereto. Seller shall retain any and all Liability for the obligations of Seller under the severance agreements listed on Schedule 6.10(o) hereto.

Section 6.11 Risk of Loss.

(a) Prior to the Closing, Buyer shall not bear any risk of loss or damage to the property included in the Purchased Assets. Seller shall replace or repair any damage to the Purchased Assets in accordance with Good Utility Practices, except as otherwise provided in paragraphs (b) or (c) below.

(b) If, before the Closing, all or any portion of the Purchased Assets is taken by eminent domain or is the subject of a pending or (to the Knowledge of Seller) contemplated taking which has not been consummated, Seller shall notify Buyer promptly in writing of such fact. If such taking would create a Material Adverse Effect, Buyer and Seller shall negotiate in good faith to settle the loss resulting from such taking (including, without limitation, by making a fair and equitable adjustment to the Purchase Price) and, upon such settlement, consummate the transactions contemplated by this Agreement pursuant to the terms of this Agreement. If no such settlement is reached within sixty (60) days after Seller has notified Buyer of such taking, then Buyer or Seller may terminate this Agreement pursuant to Section 9.1(g).

(c) If, before the Closing, all or any portion of the Purchased Assets is damaged or destroyed by fire or other casualty, Seller shall notify Buyer promptly in writing of such fact. If such damage or destruction would create a Material Adverse Effect and Seller have not notified Buyer of their intention to cure such damage or destruction within fifteen (15) days after its occurrence (such cure to be reasonably satisfactory to Buyer), Buyer and Seller shall negotiate in good faith to settle the loss resulting from such casualty (including, without limitation, by making a fair and equitable adjustment to the Purchase Price) and, upon such settlement, consummate the transactions contemplated by this Agreement pursuant to the terms of this Agreement. If no such settlement is reached within sixty (60) days after Seller have notified Buyer of such casualty, then Buyer may terminate this Agreement pursuant to Section 9.1(g).

(d) The provisions of Section 5-1311 of the New York General Obligations Law shall not apply to this Agreement.

Section 6.12 Decommissioning Funds.

(a) On the Closing Date, Seller shall cause to be transferred to the Trustee under the Post-Closing Decommissioning Trust Agreement (1) all of the assets of the Seller's Qualified Decommissioning Fund and (2) to the extent necessary to comply with Seller's Required Regulatory Approvals, all or a portion of the assets of the

Seller's Nonqualified Decommissioning Fund, in each case, consisting solely of cash or cash equivalents; provided that in no event shall the aggregate amount of the transferred assets of the Seller's Decommissioning Funds be less than the Decommissioning Target. Seller shall retain all assets of the Seller's Nonqualified Decommissioning Fund not required to be transferred under clause (2) above.

(b) In the event that the NRC requires the Buyer to provide Decommissioning funding assurance in an amount in excess of the Decommissioning Target (the "Excess Decommissioning Funds"), Buyer agrees to cause Buyer's Parent to post a Buyer's Parent Guaranty in an amount sufficient to cover the Excess Decommissioning Funds and in such form as required by the NRC. If Buyer's Parent Guaranty is not accepted by the NRC, or in all events if Seller is required to transfer Excess Decommissioning Funds to the Buyer, the Buyer shall earmark such Excess Decommissioning Funds and, upon completion of Decommissioning and termination or conversion of the NRC License by the NRC, pay to Seller an amount in dollars equal to the Excess Decommissioning Funds, together with allocated earnings on such Excess Decommissioning Funds from the Closing Date through the date such payment is made.

(c) To the extent (i) requested by Buyer, (ii) permitted by Law and (iii) that no adverse consequences result to the Seller, immediately prior to Closing, Seller shall cause to be transferred into Seller's Qualified Decommissioning Fund either (1) all of the assets in Seller's Nonqualified Decommissioning Fund, or (2) if Seller is permitted to transfer to the Trustee under the Post-Closing Decommissioning Trust Agreement only that portion of the assets of Seller's Decommissioning Funds such that the aggregate amount of the transferred assets of Seller's Decommissioning Funds equals the Decommissioning Target, that portion of the assets in Seller's Nonqualified Decommissioning Fund necessary so that the assets of Seller's Qualified Decommissioning Fund equals the Decommissioning Target. All fees in connection with implementing this Section 6.12(c), including all fees and external costs incurred for Seller to obtain a revised schedule of ruling amounts in a private letter ruling from the IRS to permit such transfer, shall be borne by Buyer.

(d) The Parties shall not take any actions that would cause the actual Tax consequences of the transactions contemplated by this Agreement to differ from or be inconsistent with the Requested Rulings set forth in Section 6.18.

Section 6.13 Spent Nuclear Fuel Fees.

(a) Except as provided in the third sentence of this paragraph and Sections 2.1(b) and 2.3(h), between the date hereof and the Closing Date, and at all times thereafter, Seller will remain liable for all Spent Nuclear Fuel Fees and any other fees associated with electricity generated at Ginna and sold prior to the Closing Date, and the One-Time DOE Pre-1983 Fee, and Buyer shall have no Liability or responsibility therefore. Buyer shall pay and discharge all Spent Nuclear Fuel Fees and any other fees associated with electricity generated at Ginna and sold from and after the Closing Date, and Seller shall have no Liability or responsibility therefore. On the

Closing Date, Buyer shall assume title to, and responsibility for the management, storage, removal, transportation and disposal of all Spent Nuclear Fuel and High Level Waste of Ginna as of the Closing Date. Seller shall assign to Buyer its undivided right, title and interest in and to the Standard Spent Fuel Disposal Contract, including, without limitation, any and all damage claims arising under such contract subject to Sections 2.1(p), 2.2(k), 6.13(b) and 6.13(d) hereof concerning the rights of Seller with respect to the One-Time DOE Pre-1983 Fee, and shall provide the required notice to the Department of Energy of the assignment of the Standard Spent Fuel Disposal Contract to Buyer within ninety (90) days of Closing, such notice to be in a form reasonably acceptable to Seller and Buyer.

(b) Prior to January 31, 2004, Seller shall commence an action in the United States Court of Federal Claims for damages resulting from the Department of Energy's failure to commence the removal, transportation, acceptance or any delay in accepting Spent Nuclear Fuel and High Level Waste for disposal pursuant to the Standard Spent Fuel Disposal Contract (the "DOE Litigation"). All rights relating to the DOE Litigation shall be exercised in good faith and such claims shall be preserved for the benefit of the Buyer. Buyer shall assume all of the rights and obligations under the Standard Spent Fuel Disposal Contract as of the Closing Date, including but not limited to the right to pursue and recover damages resulting from the DOE Litigation, subject to Seller's rights relating to the One-Time DOE Pre-1983 Fee, and provided that, in the event that Buyer shall recover any form of monetary relief (including but not limited to monetary damages or relief which is reasonably calculable from economic obligations, as a direct or indirect result of the DOE Litigation) Buyer shall pay to Seller an amount equal to the amount of the economic value received by Buyer as a result of such litigation up to a maximum payment to Seller of Ten Million Dollars ($10,000,000). Seller shall submit the complaint to be filed in the action to Buyer for prompt review, comment and approval (such approval to be in Buyer's reasonable discretion). Consistent with the obligations of this Section 6.13, Seller shall take no additional actions with respect to the DOE Litigation that may affect Buyer's interests in the suit, including but not limited to filing damages estimates or entering into any settlement discussions, without Buyer's express prior written consent; provided that Seller may take any action necessary to preserve the rights of Seller and Buyer in the DOE Litigation, or to respond to an order or request of the court or other procedural requirement, if expeditious action is required and Seller has been unable to contact or obtain a response from Buyer despite reasonable efforts to do so.

(c) Buyer agrees to provide Seller with a copy within two (2) Business Days of receipt of all notices provided to Buyer from the Department of Energy regarding the date on which the One-Time DOE Pre-1983 Fee is due and payable in accordance with the terms of the Standard Spent Fuel Disposal Contract.

(d) Seller agrees to cause the One-Time DOE Pre-1983 Fee to be duly paid when due, subject to any rights to which Seller may be entitled by reason of the Department of Energy's defaults (or alleged defaults) under the Standard Spent Fuel Disposal Contract.

Section 6.14 Department of Energy Decontamination and Decommissioning Fees.

Seller will continue to pay all Department of Energy Decontamination and Decommissioning Fees relating to Nuclear Fuel purchased and consumed at Ginna prior to the Closing Date, including but not limited to all annual Special Assessment invoices to be issued after the Closing Date by the Department of Energy, as contemplated by its regulations at 10 C.F.R. Part 766 implementing Sections 1801, 1802, and 1803 of the Atomic Energy Act.

Section 6.15 Cooperation Relating to Insurance and Price-Anderson Act. Until the Closing, Seller will maintain in effect (a) insurance in amounts and against such risks and losses as is customary in the commercial nuclear power industry and (b) not less than the level of property damage and liability insurance for the Facilities as in effect on the date hereof. Seller shall cooperate with Buyer's efforts to obtain insurance, including insurance required under the Price-Anderson Act or other Nuclear Laws with respect to the Purchased Assets. In addition, subject to Buyer's written commitment to satisfy its indemnification obligations under Section 8.1(a), Seller agrees to use Commercially Reasonable Efforts to assist Buyer in making any claims against pre-Closing insurance policies of Seller that may provide coverage related to Assumed Liabilities and Obligations. Buyer agrees to indemnify Seller for its reasonable out-of-pocket expenses incurred in providing such assistance and cooperation and not to take any action which shall adversely affect any residual rights of Seller in such insurance policies.

Section 6.16 Tax Clearance Certificates. Seller and Buyer shall cooperate and use their Commercially Reasonable Efforts to cause the Tax clearance certificates described in Schedule 4.20 of this Agreement to be issued by the appropriate taxing authorities prior to the Closing Date or as soon as practicable thereafter. Buyer shall, at least ten (10) days prior to the Closing Date, file Form AU-196.10, Notification of Sale, Transfer or Assignment in Bulk, with the New York State Department of Taxation and Finance.

Section 6.17 Release of Seller. Buyer shall use Commercially Reasonable Efforts to support Seller's efforts to obtain a written release of Seller effective as of the Closing with respect to obligations arising on or after the Closing Date under any of the Seller's Agreements, Fuel Contracts or Non-material Contracts assigned to Buyer hereunder.

Section 6.18 Private Letter Ruling. The Parties agree to cooperate in good faith in the preparation and joint filing of any private letter ruling request(s) to be made by Buyer and Seller in order to obtain the Tax treatment desired by the Parties with respect to the transfer of the Decommissioning Funds pursuant to the terms of this Agreement. Without limiting the generality of the foregoing, Buyer and Seller shall use Commercially Reasonable Efforts to obtain one or more private letter ruling(s) from the IRS determining that (i) the transfer of assets from the Seller's Qualified Decommissioning Fund to the Buyer's Qualified Decommissioning Fund is a disposition that is treated as satisfying the requirements of Treas. Reg. 1.468A-6(b) pursuant to the IRS's exercise of discretion under Treas. Reg. 1.468A-6(g)(1), and accordingly (a) neither Seller, Buyer nor their respective Qualified Decommissioning Funds will recognize gain or loss upon the transfer of assets from the Seller's Qualified Decommissioning Fund to the Buyer's Qualified Decommissioning Fund, (b) the Buyer's Qualified Decommissioning Fund will be treated as satisfying the requirements of Code Section 468A and (c) the Buyer's Qualified Decommissioning Fund will have a carryover Tax basis in the assets received from the Seller's Qualified Decommissioning Fund, (ii) Buyer will not recognize gain or otherwise take into account any income for U.S. federal income tax purposes by reason of the receipt of all or a portion of the assets of the Seller's Nonqualified Decommissioning Fund, (iii) for the taxable year that includes the Closing Date, Seller shall be entitled to a current deduction equal to the total of any amounts realized by Seller as a result of Buyer's assumption of the decommissioning obligations with regard to the Purchased Assets, (iv) at Closing, Buyer will have a Tax basis in the Purchased Assets (excluding the assets of the Qualified Decommissioning Fund) equal to the sum of the Purchase Price and the Assumed Liabilities and Obligations that will be taken into account as liabilities for federal income Tax purposes, and (v) Seller's net operating loss attributable to the decommissioning obligations assumed by Buyer will qualify for specified liability loss treatment under Section 172 of the Code (the "Requested Rulings"). The Requested Rulings shall be modified, as necessary, to take into account any Legislation or Treasury Regulations enacted on or after the date of this Agreement including, but not limited to, for the Seller to obtain a revised schedule of ruling amounts from the IRS to permit the transfer of assets in Seller's Nonqualified Decommissioning Fund to Seller's Qualified Decommissioning Fund as provided in Section 6.12(c). Neither Buyer nor Seller shall take any action that would cause the transfer of assets from the Seller's Qualified Decommissioning Fund to the Buyer's Qualified Decommissioning Fund to fail to be treated as satisfying the requirements of Treas. Reg. 1.468A-6(b) (assuming solely for purposes of this sentence that the interest acquired by Buyer constitutes a "qualified interest" in a "nuclear power plant" as defined in Treas. Reg. 1.468A-5(b)), or cause Buyer and Seller to fail to obtain such a private letter ruling. The user fee set forth in the applicable IRS Revenue Procedure for substantially identical letter rulings by a common sponsor shall be shared equally by both Parties. Each Party will bear its own legal fees with respect to any requests. The Parties agree to file the private letter ruling request seeking the Requested Rulings within 30 days of the date of this Agreement.

Section 6.19 NRC Commitments. Buyer shall maintain and operate the Facilities in accordance with the NRC Commitments to the extent required by the NRC License, applicable NRC regulations and policies and with applicable Nuclear Laws.

Section 6.20 Decommissioning. Buyer hereby agrees to commit to the NYPSC as part of receiving Buyer's Required Regulatory Approvals that it will complete, at its expense, the Decommissioning of the Facilities and the Site once the Site is no longer utilized either for power generation of any kind or for any storage of

Spent Nuclear Fuel or High Level Waste, and that it will complete all Decommissioning activities in accordance with all Nuclear Laws and Environmental Laws, including applicable requirements of the Atomic Energy Act and the NRC's rules, regulations, orders and pronouncements thereunder in effect on the date hereof.

If Buyer at any time notifies and receives approval from the NRC that it will utilize the entombment (or ENTOMB) method of Decommissioning and subsequently initiates entombment Decommissioning methods, either alone or in combination with any other Decommissioning method or methods, in accordance with then-existing NRC regulations, then Buyer shall cause to be paid to Seller within ninety (90) days following such initiation of entombment Decommissioning methods an amount in dollars equal to the Excess Decommissioning Funds. To the extent permitted by Law and the trust agreements relating to the Buyer's Decommissioning Funds, such payment may be made from the Buyer's Decommissioning Funds. All payments made by Buyer to Seller pursuant to this Section 6.20 shall be flowed through by Seller to its ratepayers as directed by the NYPSC; provided, however, that Seller shall be obligated to flow through benefits to ratepayers only if and to the extent that payments are received from Buyer. In no event shall Seller or its shareholders be financially responsible for flowing through payments to ratepayers based on payments owed to Seller but not received from Buyer. The Parties acknowledge that Seller shall have no obligation to audit, monitor or enforce rights and obligations with respect to this Section 6.20 and anticipate that the NYPSC will assume all such obligations.

Section 6.21 Uprate.

(a) Between the date hereof and the Closing Date, Seller shall enter into a contract with a technically qualified vendor(s), as required, to complete the necessary nuclear steam supply system and balance of plant licensing and engineering uprate reports (together, the "Uprate Reports"), including but not limited to a sufficient NRC License amendment request ("LAR") with the goal of uprating the licensed thermal output of the Facilities to 1781 MegaWatt thermal (the "Uprate"). Seller shall use its commercially reasonable best efforts to complete the Uprate Reports and prepare the LAR as soon as practicable.

(b) Buyer and Seller agree to cooperate in good faith in the preparation of the Uprate Reports and any related activities. Seller agrees that Buyer approval is required in connection with all material aspects of the preparation of the Uprate Reports, including but not limited to vendor selection, costs, content, deliverables, and schedule. Seller shall accommodate any reasonable request of Buyer with respect to preparation or implementation activities associated with the Uprate to the extent that Seller reasonably determines on the advice of legal counsel that such activity is permitted in accordance with its authority under its NRC License. Such activities may include the design, material procurement, scheduling of, and preparation for, reasonable Uprate related modifications to be performed in the Spring refueling outage, or sooner.

(c) Subject to Seller's compliance with subsection (b), Buyer shall reimburse to the Seller, in accordance with Section 3.3, the vendor costs associated with preparing the Uprate Reports and any other vendor associated with the Uprate that were requested by the Buyer prior to the Closing. In the event that Closing does not occur, Seller and Buyer agree to negotiate in good faith the sharing of vendor costs associated with the preparation of the Uprate Reports and related vendor costs associated with Uprate activities requested by the Buyer.

Section 6.22 Right of First Refusal. Buyer and Seller agree to negotiate in good faith with respect to a right of first refusal agreement from Seller in favor of Buyer containing reasonable terms for the acquisition after the Closing Date of the approximately 15 acre site now or formerly owned by Roxdel Corporation and acquired by Roxdel Corporation from Elizabeth Gates.

ARTICLE 7

CONDITIONS

Section 7.1 Conditions to Obligations of Buyer. The obligations of Buyer to purchase the Purchased Assets and to consummate the other transactions contemplated by this Agreement shall be subject to the fulfillment at or prior to the Closing Date (or the waiver by Buyer) of the following conditions:

(a) All applicable waiting periods under the HSR Act relating to the consummation of the transactions contemplated hereby shall have expired or been terminated;

(b) No preliminary or permanent injunction or other order or decree by any federal or state court or Governmental Authority which restrains or prevents the consummation of the transactions contemplated hereby shall have been issued and remain in effect (each Party agreeing to cooperate in all efforts to have any such injunction, order or decree lifted) and no statute, rule or regulation shall have been enacted by any state or federal government or Governmental Authority which prohibits the consummation of the transactions contemplated hereby;

(c) Buyer shall have received all of Buyer's Required Regulatory Approvals, in form and substance reasonably satisfactory (including no materially adverse conditions as described in Section 9.1(c)) to Buyer and such approvals shall be in full force and effect and either (i) shall be final and non-appealable or (ii) if not final and non-appealable, shall not be subject to the possibility of appeal, review or reconsideration which, in the reasonable opinion of Buyer is likely to be successful and, if successful, would have a Material Adverse Effect, or a material adverse effect on the business, assets, operations or condition (financial or otherwise) of Buyer;

(d) Seller shall have received all of Seller's Required Regulatory Approvals (other than those the failure of which to obtain could not reasonably be expected to result in a Material Adverse Effect or a material adverse effect on the business, assets, operations or condition (financial or otherwise) of Buyer), none of such approvals shall contain any conditions that could reasonably be expected to result in a Material Adverse Effect, or a material adverse effect on the business, assets, operations or condition (financial or otherwise) of Buyer, and such approvals shall be in full force and effect and either (i) shall be final and non-appealable or (ii) if not final and non- appealable, shall not be subject to the possibility of appeal, review or reconsideration which, in the reasonable opinion of Buyer is likely to be successful and, if successful, would have a Material Adverse Effect, or a material adverse effect on the business, assets, operations or condition (financial or otherwise) of Buyer;

(e) Seller shall have performed and complied in all material respects with the covenants and agreements contained in this Agreement which are required to be performed and complied with by Seller on or prior to the Closing Date;

(f) The representations and warranties of Seller set forth in this Agreement that are qualified by materiality shall be true and correct as of the Closing Date and all other representations and warranties of Seller shall be true and correct in all material respects as of the Closing Date, in each case as though made at and as of the Closing Date;

(g) Buyer shall have received a certificate from an authorized officer of Seller, dated the Closing Date, to the effect that, to such officer's knowledge, the conditions set forth in Section 7.1(e), (f), (k), (m) and (q) have been satisfied by Seller;

(h) Buyer shall have received an opinion from Seller's counsel and Seller's Parent's counsel reasonably acceptable to Buyer, dated the Closing Date and reasonably satisfactory in form and substance to Buyer and its counsel, substantially in the form of Exhibit "H" hereto;

(i) Seller shall have delivered, or caused to be delivered, to Buyer at the Closing, Seller's closing deliveries described in Sections 3.6 and 3.8;

(j) Buyer shall have received from a title insurance company selected by Buyer (collectively with any co-insurer or re-insurer, as applicable, the "<u>Title Company</u>") an ALTA owner's title insurance policy on the Real Property and the Cooling Tunnel Easement, in form and substance reasonably satisfactory to Buyer, insuring (at the Title Company's regular rates) fee simple title as described in Section 4.7 subject only to Permitted Encumbrances; <u>provided</u>, <u>however</u>, that if any title insurance company selected by Buyer declines to issue such a policy, Buyer shall select another title insurance company (if a title insurance company reasonably acceptable to Buyer is willing to issue such a policy); and further provided, however, that any such policy will not insure fee simple title to the Cooling Tunnel Easement and the Facilities associated therewith. Buyer shall provide Seller with a copy of each title report received by Buyer from the Title Company.

(k) Since the date hereof, no Material Adverse Effect shall have occurred and be continuing;

(l) The lien of the Mortgage Indenture on the Purchased Assets shall have been released and any documents necessary to evidence such release shall have been delivered to Buyer and the Title Company;

(m) The Seller shall have transferred to the Trustee of Post-Closing Decommissioning Trust Agreement a portion or all of the Decommissioning Funds, in accordance with Section 6.12;

(n) Legislation or Treasury Regulations shall have not been enacted or promulgated that, in the opinion of nationally-recognized tax counsel, would have a material adverse effect on the tax consequences to Buyer contemplated in Section 6.18;

(o) The NRC shall have issued a renewed NRC License for Ginna for a period of not less than twenty (20) years beyond its original license term;

(p) The Ancillary Agreements shall be in full force and effect as of the Closing Date; and

(q) The Facilities shall have been operating at an average of not less than 95% of their licensed thermal output for a period of fourteen (14) days immediately preceding the Closing Date.

Section 7.2 Conditions to Obligations of Seller. The obligation of Seller to sell the Purchased Assets and to consummate the other transactions contemplated by this Agreement shall be subject to the fulfillment at or prior to the Closing Date (or the waiver by Seller) of the following conditions:

(a) All applicable waiting periods under the HSR Act relating to the consummation of the transactions contemplated hereby shall have expired or been terminated;

(b) No preliminary or permanent injunction or other order or decree by any federal or state court or Governmental Authority which restrains or prevents the consummation of the transactions contemplated hereby shall have been issued and remain in effect (each Party agreeing to use its Commercially Reasonable Efforts to have any such injunction, order or decree lifted) and no statute, rule or regulation shall have been enacted by any state or federal government or Governmental Authority in the United States which prohibits the transactions contemplated hereby;

(c) Seller shall have received all of the Seller's Required Regulatory Approvals, in form and substance reasonably satisfactory (including no materially adverse conditions as described in Section 9.1(d)) to Seller and such approvals shall be in full force and effect and either (i) shall be final and non-appealable or (ii) if not final and non-appealable, shall not be subject to the possibility of appeal, review or reconsideration which, in the reasonable opinion of the Seller (A) is likely to be successful and (B), if successful, would have a material adverse effect on the operations or conditions (financial or otherwise) of the Seller;

(d) Buyer shall have received all Buyer's Required Regulatory Approvals (other than those the failure of which to obtain could not reasonably be expected to result in a material adverse effect on the business, assets, operations or condition (financial or otherwise) of Seller), none of such approvals shall contain any conditions that could reasonably be expected to result in a material adverse effect on the business, assets, operations or condition (financial or otherwise) of Seller, and such approvals shall be in full force and effect and either (i) shall be final and non-appealable or (ii) if not final and non-appealable, shall not be subject to the possibility of appeal, review or reconsideration which, in the reasonable opinion of Seller (A) is likely to be successful and (B) if successful, would have a material adverse effect on the business, assets, operations or condition (financial or otherwise) of Seller;

(e) Buyer shall have performed and complied with in all material respects the covenants and agreements contained in this Agreement which are required to be performed and complied with by Buyer on or prior to the Closing Date;

(f) The representations and warranties of Buyer set forth in this Agreement that are qualified by materiality shall be true and correct as of the Closing Date and all other representations and warranties of Buyer shall be true and correct in all material respects as of the Closing Date, in each case as though made at and as of the Closing Date;

(g) Seller shall have received certificates from an authorized officer of Buyer, dated the Closing Date, to the effect that, to the knowledge of such officer the conditions set forth in Sections 7.2(e) and (f) have been satisfied by Buyer;

(h) Seller shall have received an opinion from Buyer's counsel and Buyer's Parent's counsel reasonably acceptable to Seller, dated the Closing Date and reasonably satisfactory in form and substance to Seller and its counsel, substantially in the form of Exhibit "T" hereto;

(i) Buyer shall have delivered, or caused to be delivered, to Seller at the Closing, Buyer's closing deliveries described in Section 3.7;

(j) The lien of the Mortgage Indenture on the Purchased Assets shall have been released and any documents necessary to evidence such release shall have been delivered to the title company;

(k) Legislation or Treasury Regulations shall have not been enacted or promulgated that, in the opinion of nationally-recognized tax counsel, would have a material adverse effect on the tax consequences to Seller contemplated in Section 6.18; and

(l) The NRC shall have issued a renewed NRC License for Ginna for a period of not less than twenty (20) years beyond its original license term.

ARTICLE 8

INDEMNIFICATION

Section 8.1 Indemnification.

(a) Following the Closing, Buyer shall indemnify, defend and hold harmless Seller, its officers, directors, employees, shareholders, Affiliates and agents (each, a "Seller Indemnitee") from and against any and all claims, demands, suits, losses, liabilities, damages, obligations, payments, costs and expenses (including, without limitation, the costs and expenses of any and all actions, suits, proceedings, assessments, judgments, settlements and compromises relating thereto and reasonable attorneys' fees and reasonable disbursements in connection therewith) (each, an "Indemnifiable Loss"), asserted against or suffered by any Seller Indemnitee relating to, resulting from or arising out of (i) any breach by Buyer of the representations and warranties which survive the Closing or any covenants contained in this Agreement; provided, however, that in the case of breaches of representations, warranties or covenants contained in Article V, only to the extent that such Indemnifiable Loss in the aggregate exceed One Million Dollars ($1,000,000), and provided further that in no event shall Buyer have liability for indemnification for an Indemnifiable Loss relating to, resulting from or arising out of matters set forth in this clause (i) of Section 8.1(a) that individually is less than Two Hundred and Fifty Thousand Dollars ($250,000), (ii) the Assumed Liabilities and Obligations, (iii) any Third Party Claims against a Seller Indemnitee arising out of or in connection with Buyer's ownership or operation of the Purchased Assets on or after the Closing Date, (iv) any actions taken by Buyer which shall result in tax consequences to the Seller or Seller's Qualified Decommissioning Fund which are different for Seller or Seller's Qualified Decommissioning Fund from those contemplated in Section 6.18, and (v) all Transfer Taxes for which Buyer is liable under Section 6.8.

(b) Following the Closing, Seller shall indemnify, defend and hold harmless Buyer, its officers, directors, members, employees, shareholders, Affiliates and agents (each, a "Buyer Indemnitee") from and against any and all Indemnifiable Losses asserted against or suffered by any Buyer Indemnitee relating to, resulting from or arising out of (i) any breach by Seller of the representations and warranties which survive the Closing or any covenants contained in this Agreement provided, however, in the case of breaches of representations, warranties or covenants contained in Article IV, only to the extent that such Indemnifiable Losses in the aggregate exceed One Million Dollars ($1,000,000), and provided further that in no event shall Seller have any liability for indemnification for an Indemnifiable Loss relating to, resulting from or arising out of matters set forth in this clause (i) of Section 8.1(b) that individually is less than Two Hundred and Fifty Thousand Dollars ($250,000), (ii) the Excluded Liabilities, (iii) noncompliance by Seller with any bulk sales or transfer laws as provided in Section 10.11, (iv) any Third Party Claims against a Buyer Indemnitee arising out of or in connection with Seller's ownership or operation of the Purchased Assets on or prior to the Closing Date (other than any Third Party Claims that are Assumed Liabilities), (v) any Third Party Claims against a Buyer Indemnitee arising out of or in connection with Seller's ownership or operation of the Excluded Assets, (vi) all Taxes incurred by reason of any act of Seller that either constitutes an act of "self-dealing" as defined in Treas. Reg. § 1.468A-5(b)(2) or results in the disqualification of the Qualified Decommissioning Funds under Treas. Reg. § 1.468A-5 other than as a result of any action required or contemplated by this Agreement including, without limitation, the transfer contemplated by Section 5.7 hereof, or (vii) any claims or attachments of Seller or Seller's creditor against the Decommissioning Funds after the Closing Date.

(c) The expiration or termination of any representation or warranty shall not affect the Parties' obligations under this Section 8.1 if the Indemnitee provided the Person required to provide indemnification under this Agreement (the "Indemnifying Party") with proper notice of the claim or event for which indemnification is sought prior to such expiration, termination or extinguishment.

(d) Except to the extent otherwise provided in Article 9 or in Section 6.8(e), the rights and remedies of Seller and Buyer under this Article 8 are exclusive and in lieu of any and all other rights and remedies which Seller and Buyer may have under this Agreement or otherwise for monetary relief, with respect to (i) any breach of or failure to perform any covenant, agreement, or representation or warranty set forth in this Agreement, after the occurrence of the Closing, or (ii) the Assumed Liabilities and Obligations or the Excluded Liabilities, as the case may be. The indemnification obligations of the Parties set forth in this Article 8 apply only to matters arising out of this Agreement, excluding the Ancillary Agreements. Any Indemnifiable Loss arising under or pursuant to an Ancillary Agreement shall be governed by the indemnification obligations, if any, contained in the Ancillary Agreement under which the Indemnifiable Loss arises. The maximum aggregate exposure for indemnity by Seller or Buyer for any and all claims of breaches of representations or warranties made hereunder and indemnification of claims relating thereto shall be Twenty Million Dollars ($20,000,000).

(e) Notwithstanding anything to the contrary herein except for Section 6.8(e), no Party (including an Indemnitee) shall be entitled to recover from any other Party (including an Indemnifying Party) for any liabilities, damages, obligations, payments, losses, costs or expenses under this Agreement any amount in excess of the actual compensatory damages, court costs and reasonable attorney's and other advisor fees suffered by such Party. Buyer and Seller waive any right to recover punitive, incidental, special, exemplary and consequential damages arising in connection with or with respect to this Agreement including, but not limited to, losses or damages caused by reason of unavailability of Ginna, plant shutdowns or service interruptions, loss of use, profits or revenue, inventory or use charges, cost of purchased or replacement power, interest charges or cost of capital. The provisions of this Section 8.1(e) shall not apply to indemnification for a Third Party Claim.

(f) The Parties agree to treat all payments relating to indemnifications as adjustments to the Purchase Price to the extent allowed by law.

Section 8.2 Defense of Claims.

(a) If any Indemnitee receives notice of the assertion of any claim or of the commencement of any claim, action, or proceeding made or brought by any Person who is not a Party to this Agreement or any Affiliate of a Party to this Agreement (a "Third Party Claim"), including but not limited to an information document request or a notice of proposed disallowance issued by the Internal Revenue Service relating to a matter covered by Section 5.7, with respect to which indemnification is to be sought from an Indemnifying Party, the Indemnitee shall give such Indemnifying Party reasonably prompt written notice thereof, but in any event such notice shall not be given later than twenty (20) calendar days after the Indemnitee's receipt of notice of such Third Party Claim. Such notice shall describe the nature of the Third Party Claim in reasonable detail and shall indicate the estimated amount, if practicable, of the Indemnifiable Loss that has been or may be sustained by the Indemnitee. The Indemnifying Party will have the right to participate in or, by giving written notice to the Indemnitee, to elect to assume the defense of any Third Party Claim at such Indemnifying Party's expense and by such Indemnifying Party's own counsel, provided that the counsel for the Indemnifying Party who shall conduct the defense of such Third Party Claim shall be reasonably satisfactory to the Indemnitee. The Indemnitee shall cooperate in good faith in such defense at such Indemnitee's own expense. If an Indemnifying Party elects not to assume the defense of any Third Party Claim, the Indemnitee may compromise or settle such Third Party Claim over the objection of the Indemnifying Party, which settlement or compromise shall conclusively establish the Indemnifying Party's Liability pursuant to this Agreement; provided, however, the Indemnitee provides written notice to the Indemnifying Party of its intent to settle and such notice reasonably describes the terms of such settlement at least ten (10) Business Days prior to entering into any settlement.

(b) (i) If, within twenty (20) calendar days after an Indemnitee provides written notice to the Indemnifying Party of any Third Party Claims, the Indemnitee receives written notice from the Indemnifying Party that such Indemnifying Party has elected to assume the defense of such Third Party Claim as provided in Section 8.2 (a), the Indemnifying Party will not be liable for any legal expenses subsequently incurred by the Indemnitee in connection with the defense thereof; provided, however, that if the Indemnifying Party shall fail to take reasonable steps necessary to defend diligently such Third Party Claim within twenty (20) calendar days after receiving notice from the Indemnitee that the Indemnitee believes the Indemnifying Party has failed to take such steps, the Indemnitee may assume its own defense and the Indemnifying Party shall be liable for all reasonable expenses thereof.

(ii) Without the prior written consent of the Indemnitee, which consent shall not be unreasonably withheld or delayed, the Indemnifying Party shall not enter into any settlement of any Third Party Claim which would lead to Liability or create any financial or other obligation on the part of the Indemnitee for which the Indemnitee is not entitled to indemnification hereunder. If a firm offer is made to settle a Third Party Claim without leading to Liability or the creation of a financial or other obligation on the part of the Indemnitee for which the Indemnitee is not entitled to indemnification hereunder and the Indemnifying Party desires to accept and agree to such offer, the Indemnifying Party shall give written notice to the Indemnitee to that effect. If the Indemnitee fails to consent to such firm offer within twenty (20) calendar days after its receipt of such notice, the Indemnifying Party shall be relieved of its obligations to defend such Third Party Claim and the Indemnitee may contest or defend such Third Party Claim. In such event, the maximum Liability of the Indemnifying Party as to such Third Party Claim will be the amount of such settlement offer plus reasonable costs and expenses paid or incurred by Indemnitee up to the date of said notice.

(c) Any claim by an Indemnitee on account of an Indemnifiable Loss which does not result from a Third Party Claim (a "Direct Claim") shall be asserted by giving the Indemnifying Party reasonably prompt written notice thereof, stating the nature of such claim in reasonable detail and indicating the estimated amount, if practicable, but in any event such notice shall not be given later than twenty (20) calendar days after the Indemnitee becomes aware of such Direct Claim, and the Indemnifying Party shall have a period of twenty (20) calendar days within which to respond to such Direct Claim. If the Indemnifying Party does not respond within such twenty (20) calendar day period, the Indemnifying Party shall be deemed to have accepted such claim. If the Indemnifying Party rejects such claim, the Indemnitee will be free to seek enforcement of its right to indemnification under this Agreement.

(d) The amount of any Indemnifiable Loss shall be reduced to the extent that the Indemnitee receives any insurance proceeds with respect to an Indemnifiable Loss. If the amount of any Indemnifiable Loss, at any time subsequent to the making of an indemnity payment in respect thereof, is reduced by recovery, settlement or otherwise under or pursuant to any insurance coverage, or pursuant to any claim, recovery, settlement or payment by, from or against any other entity, the amount of such reduction, less any costs, expenses or premiums incurred in connection therewith (together with interest thereon from the date of payment thereof to the date or repayment at the "prime rate" as published in The Wall Street Journal) shall promptly be repaid by the Indemnitee to the Indemnifying Party.

(e) A failure to give timely notice as provided in this Section 8.2 shall not affect the rights or obligations of any Party hereunder except if, and only to the extent that, as a result of such failure, the Party which was entitled to receive such notice was actually prejudiced as a result of such failure.

ARTICLE 9

TERMINATION

Section 9.1 Termination.

(a) This Agreement may be terminated at any time prior to the Closing Date by mutual written consent of Seller and Buyer.

(b) This Agreement may be terminated by Seller or Buyer, if (i) any federal or state court of competent jurisdiction shall have issued an order, judgment or decree permanently restraining, enjoining or otherwise prohibiting the Closing, and such order, judgment or decree shall have become final and nonappealable; (ii) any statute, rule, order or regulation shall have been enacted or issued by any Governmental Authority which, directly or indirectly, prohibits the consummation of the Closing; or (iii) the Closing contemplated hereby shall have not occurred on or before December 31, 2004 (the "Termination Date"); provided that the right to terminate this Agreement under this Section 9.1(b)(iii) shall not be available to any Party whose failure to fulfill any obligation under this Agreement has been the cause of, or resulted in, the failure of the Closing to occur on or before such date and provided, further, that if on the Termination Date the conditions to the Closing set forth in Sections 7.1(c), 7.1(d), 7.2(c) or 7.2(d) shall not have been fulfilled but all other conditions to the Closing shall be fulfilled or shall have been capable of being fulfilled, then the Termination Date shall be June 30, 2005.

(c) This Agreement may be terminated by Buyer if any of Seller's Required Regulatory Approvals or Buyer's Required Regulatory Approvals, the receipt of which is a condition to the obligation of Buyer to consummate the Closing as set forth in Sections 7.1(c) and 7.1(d), shall have been denied or shall have been granted but are not in form and substance reasonably satisfactory to Buyer because one of such approvals contains a condition that would have a Material Adverse Effect or a material adverse effect on the business, assets, operations or condition (financial or otherwise) of Buyer.

(d) This Agreement may be terminated by Seller if any of the Seller's Required Regulatory Approvals or Buyer's Regulatory Approvals, the receipt of which are a condition to the obligation of Seller to consummate the Closing as set forth in Section 7.2(c) and Section 7.2(d), shall have been denied or shall have been granted but are not in form and substance reasonably satisfactory to Seller, because one of such approvals contains a condition that would have a material adverse effect on the business, assets, operations or condition (financial or otherwise) of Seller.

(e) This Agreement may be terminated by Buyer if there has been a material violation or breach by Seller of any applicable covenant, representation or warranty contained in this Agreement and such violation or breach (i) is not cured by the earlier of the Closing Date or thirty (30) days after receipt by Seller (or by Buyer in the case of notice by Seller pursuant to Section 6.9) of written notice specifying particularly such violation or breach (provided that in the event Seller is attempting to cure the violation or breach in good faith, then Buyer may not terminate pursuant to this provision unless the violation or breach is not cured by the earlier of the Closing Date or the Termination Date), and (ii) such violation or breach has not been waived by Buyer.

(f) This Agreement may be terminated by Seller if there has been a material violation or breach by Buyer or Parent of any covenant, representation or warranty contained in this Agreement and such violation or breach (i) is not cured by the earlier of the Closing Date or thirty (30) days after receipt by Buyer or Parent (or by Seller in the case of notice by Buyer or Parent pursuant to Section 6.9) of written notice specifying particularly such violation or breach (provided that in the event Buyer or Parent, as the case may be, is attempting to cure the violation or breach in good faith, then Seller may not terminate pursuant to this provision unless the violation or breach is not cured by the earlier of the Closing Date or the Termination Date), and (ii) such violation or breach has not been waived by Seller.

(g) This Agreement may be terminated by Buyer or Seller in accordance with the provisions of Sections 6.11(b) or (c).

(h) This Agreement may be terminated by Seller if one of the events the non-occurrence of which is a condition to closing in Section 7.2(l) occurs, which is reasonably likely to have a material adverse effect on the business, assets, operations or condition (financial or otherwise) of Seller.

(i) This Agreement may be terminated by Buyer if one of the events the non-occurrence of which is a condition to Closing in Section 7.1(n) occurs, which is reasonably likely to have a material adverse effect on the business, assets, operations or condition (financial or otherwise) of Buyer.

Section 9.2 Procedure and Effect of No Default Termination. In the event of termination of this Agreement by any Party pursuant to this Section 9, written notice thereof shall forthwith be given by the terminating Party to the other Parties, whereupon (but only in the case of termination pursuant to Subsections (e) or (f) of Section 9.1 where a breach of a covenant, representation or warranty by the non-terminating Party is not willful), the liabilities of the Parties hereunder will terminate, except as otherwise expressly provided in this Agreement, and thereafter no Party shall have any recourse against any of the other Parties by reason of this Agreement.

ARTICLE 10

MISCELLANEOUS PROVISIONS

Section 10.1 Amendment and Modification. Subject to applicable law, this Agreement may be amended, modified or supplemented only by written agreement of Seller and Buyer.

Section 10.2 Waiver of Compliance; Consents. Except as otherwise provided in this Agreement, any failure of any of the Parties to comply with any obligation, covenant, agreement or condition herein may be waived by the Party entitled to the benefits thereof only by a written instrument signed by the Party granting such waiver, but such waiver of such obligation, covenant, agreement or condition shall not operate as a waiver of, or estoppel with respect to, any subsequent failure to comply therewith.

Section 10.3 Survival of Representations, Warranties, Covenants and Obligations.

(a) The representations and warranties given or made by any Party to this Agreement or in the certificates required by Section 7.1(f) or 7.2(g) shall survive the Closing for a period of twelve (12) months except that (i) all representations and warranties relating to Taxes and Tax Returns and the representations and warranties in Sections 4.10 and 4.12 shall survive the Closing for the period of the applicable statutes of limitation plus any extensions or waivers thereof and (ii) all representations and warranties set forth in Sections 4.1, 4.2, 4.21, 4.22, 5.7 and 6.7 hereof shall survive the Closing indefinitely. Each Party shall be entitled to rely upon the representations and warranties of the other Party or Parties set forth herein, notwithstanding any investigation or audit conducted before or after the Closing Date or the decision of any Party to complete the Closing.

(b) The covenants and obligations of the Parties set forth in this Agreement, including without limitation the indemnification obligations of the Parties under Article 8 hereof, shall survive the Closing indefinitely, and the Parties shall be entitled to the full performance thereof by the other Parties hereto without limitation as to time or amount (except as otherwise specifically set forth herein).

Section 10.4 Notices. All notices and other communications hereunder shall be in writing and shall be deemed given if delivered personally or by facsimile transmission, or mailed by overnight courier or registered or certified mail (return receipt requested), postage prepaid, to the recipient Party at its address (or at such other address or facsimile number for a Party as shall be specified by like notice; provided, however, that notices of a change of address shall be effective only upon receipt thereof):

(a) If to Seller, to:

Rochester Gas and Electric Corporation
89 East Avenue
Rochester, NY 14649
Attention: President

with a copy to:

Huber Lawrence & Abell
605 Third Avenue
New York, NY 10158
Attention: John D. Draghi, Esq.

and

LeBoeuf, Lamb, Greene & MacRae, L.L.P.
125 West 55th Street
New York, NY 10019
Attention: Sheri E. Bloomberg, Esq.

(b) if to Buyer, to:

Constellation Generation Group, LLC
750 East Pratt Street
18th Floor
Baltimore, Maryland 21202
Attention: President

with a copy to:

Constellation Energy Group, Inc.
750 East Pratt Street
18th Floor
Baltimore, Maryland 21202
Attention: General Counsel

(c) if to Buyer's Parent, to:

Constellation Energy Group, Inc.
750 East Pratt Street
18th Floor
Baltimore, Maryland 21202
Attention: Vice President - Corporate Strategy and Development

with a copy to:

Constellation Energy Group, Inc.
750 East Pratt Street
18th Floor
Baltimore, Maryland 21202
Attention: General Counsel

Section 10.5 Assignment. This Agreement and all of the provisions hereof shall be binding upon and inure to the benefit of the Parties hereto and their respective successors and permitted assigns, but neither this Agreement nor any of the rights, interests or obligations hereunder shall be assigned by any Party hereto, including by operation of law, without the prior written consent of each other Party, such consent not to be unreasonably withheld, nor is this Agreement intended (except as specifically provided herein) to confer upon any other Person except the Parties hereto any rights, interests, obligations or remedies hereunder. Any assignment in contravention of the foregoing sentence shall be null and void and without legal effect on the rights and obligations of the Parties hereunder. No provision of this Agreement shall create any third party beneficiary rights in any employee or former employee of Seller (including any beneficiary or dependent thereof) in respect of continued employment or resumed employment, and no provision of this Agreement shall create any rights in any such Persons in respect of any benefits that may be provided, directly or indirectly, under any employee benefit plan or arrangement except as expressly provided for thereunder. Notwithstanding the foregoing, but subject to all applicable legal requirements, (i) Buyer or its permitted assignee may grant a security interest in the rights and interests hereunder to a trustee, lending institution or other party for the purposes of leasing, financing or refinancing the Purchased Assets, (ii) Buyer or its permitted assignee may assign, transfer, pledge or otherwise dispose of (absolutely or as security) its rights and interests hereunder to a directly or indirectly wholly-owned Affiliate of Buyer; provided, however, that no such assignment shall relieve or discharge Buyer from any of its obligations hereunder or shall be made if it would reasonably be expected to prevent or materially impede, interfere with or delay the transactions contemplated by this Agreement or materially increase the costs (to the non-assigning party) of the transactions contemplated by this Agreement. Seller agrees, at Buyer's expense, to execute and deliver such documents as may be reasonably necessary to accomplish any such assignment, transfer, pledge or other disposition of rights and interests hereunder so long as Seller's rights under this Agreement are not thereby altered, amended, diminished or otherwise impaired. In the event Buyer assigns this agreement pursuant to this Section 10.5, such assignee shall be defined as "Buyer" for all purposes hereunder thereafter.

Section 10.6 Governing Law. This Agreement shall be governed by and construed in accordance with the law of the State of New York (without giving effect to conflict of law principles) as to all matters, including but not limited to matters of validity, construction, effect, performance and remedies. THE PARTIES HERETO AGREE THAT VENUE IN ANY AND ALL ACTIONS AND PROCEEDINGS

RELATED TO THE SUBJECT MATTER OF THIS AGREEMENT SHALL BE IN THE STATE AND FEDERAL COURTS FOR MONROE COUNTY, NEW YORK, WHICH COURTS SHALL HAVE EXCLUSIVE JURISDICTION FOR SUCH PURPOSE (EXCEPT WHERE SUCH ACTION OR PROCEEDING IS REQUIRED BY LAW TO BE IN WAYNE COUNTY), AND THE PARTIES HERETO IRREVOCABLY SUBMIT TO THE EXCLUSIVE JURISDICTION OF SUCH COURTS AND IRREVOCABLY WAIVE THE DEFENSE OF AN INCONVENIENT FORUM TO THE MAINTENANCE OF ANY SUCH ACTION OR PROCEEDING. SERVICE OF PROCESS MAY BE MADE IN ANY MANNER RECOGNIZED BY SUCH COURTS. EACH OF THE PARTIES HERETO IRREVOCABLY WAIVES ITS RIGHT TO A JURY TRIAL WITH RESPECT TO ANY ACTION OR CLAIM ARISING OUT OF ANY DISPUTE IN CONNECTION WITH THIS AGREEMENT OR THE TRANSACTIONS CONTEMPLATED HEREBY.

Section 10.7 Counterparts. This Agreement may be executed in two or more counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument.

Section 10.8 Interpretation. The articles, section and schedule headings contained in this Agreement are solely for the purpose of reference, are not part of the agreement of the Parties and shall not in any way affect the meaning or interpretation of this Agreement.

Section 10.9 Schedules and Exhibits. Except as otherwise provided in this Agreement, all Exhibits and Schedules referred to herein are intended to be and hereby are specifically made a part of this Agreement.

Section 10.10 Entire Agreement. This Agreement, the Confidentiality Agreement and the Ancillary Agreements, including the Exhibits, Schedules, documents, certificates and instruments referred to herein or therein, and any other documents that specifically reference this Section 10.10, embody the entire agreement and understanding of the Parties hereto in respect of the transactions contemplated by this Agreement and supersedes all prior agreements and understandings between the Parties other than the Confidentiality Agreement with respect to such transactions. There are no restrictions, promises, representations, warranties, covenants or undertakings, other than those expressly set forth or referred to herein or therein. It is expressly acknowledged and agreed that there are no restrictions, promises, representations, warranties, covenants or undertakings contained in any material made available to Buyer pursuant to the terms of the Confidentiality Agreement.

Section 10.11 Bulk Sales Laws. Buyer acknowledges that, notwithstanding anything in this Agreement to the contrary, Seller will not comply with the provision of the bulk sales laws of any jurisdiction in connection with the transactions contemplated by this Agreement. Buyer hereby waives compliance by Seller with the provisions of the bulk sales laws of all applicable jurisdictions.

Section 10.12 No Joint Venture. Nothing in this Agreement creates or is intended to create an association, trust, partnership, joint venture or other entity or similar legal relationship among the Parties, or impose a trust, partnership or fiduciary duty, obligation, or liability on or with respect to the Parties. Except as expressly provided herein, neither Party is or shall act as or be the agent or representative of the other Party.

Section 10.13 Change in Law. If and to the extent that any Laws or regulations that govern any aspect of this Agreement shall change, so as to make any aspect of this transaction unlawful, then the Parties agree to make such modifications to this Agreement as may be reasonably necessary for this Agreement to accommodate any such legal or regulatory changes, without materially changing the overall benefits or consideration expected hereunder by any Party.

Section 10.14 Buyer's Parent Support. From the date hereof until the effectiveness of the Closing, Buyer's Parent agrees to provide Buyer any and all financial support necessary to permit Buyer to perform its obligations hereunder.

Section 10.15 Severability. Any term or provision of this Agreement that is held invalid or unenforceable in any situation shall not affect the validity or enforceability of the remaining terms and provisions hereof or the validity or enforceability of the offending term or provision in any other situation, provided, however, that the remaining terms and provisions of this Agreement may be enforced only to the extent that such enforcement in the absence of any invalid terms and provisions would not result in (a) deprivation of a Party of a material aspect of its original bargain upon execution of this Agreement or any of the Ancillary Agreements, (b) unjust enrichment of a Party, or (c) any other manifestly unfair or inequitable result.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be signed by their respective duly authorized officers as of the date first above written.

ROCHESTER GAS AND ELECTRIC CORPORATION

By: /s/ Joseph J. Syta
Name: Joseph J. Syta
Title: Controller and Treasurer

CONSTELLATION GENERATION GROUP, LLC

By: /s/ Michael J. Wallace
Name: Michael J. Wallace
Title: President

Solely for purposes of Article 5 and Sections 6.12(b) and 10.14:
CONSTELLATION ENERGY GROUP, INC.

By: /s/ Mark P. Huston
Name: Mark. P. Houston
Title: Vice President - Strategy

IN WITNESS WHEREOF, the Parties have caused this Agreement to be signed by their respective duly authorized officers as of the date first above written.

ROCHESTER GAS AND ELECTRIC CORPORATION

By:________________________
Name: Joseph J. Syta
Title: Controller and Treasurer

CONSTELLATION GENERATION GROUP, LLC

By:________________________
Name:
Title:
Solely for purposes of Article 5 and Sections 6.12(b) and 10.14:
CONSTELLATION ENERGY GROUP, INC.

By:________________________
Name:
Title:

IN WITNESS WHEREOF, the Parties have caused this Agreement to be signed by their respective duly authorized officers as of the date first above written.

ROCHESTER GAS AND ELECTRIC CORPORATION

By: ___________________________
Name:
Title:

CONSTELLATION GENERATION GROUP, LLC

By: ___________________________
Name: Michael J. Wallace
Title: President

Solely for purposes of Article 5 and Sections 6.12(b) and 10.14:
CONSTELLATION ENERGY GROUP, INC.

By: ___________________________
Name:
Title:

IN WITNESS WHEREOF, the Parties have caused this Agreement to be signed by their respective duly authorized officers as of the date first above written.

ROCHESTER GAS AND ELECTRIC CORPORATION

By: ______________________
Name:
Title:

CONSTELLATION GENERATION GROUP, LLC

By: ______________________
Name:
Title:

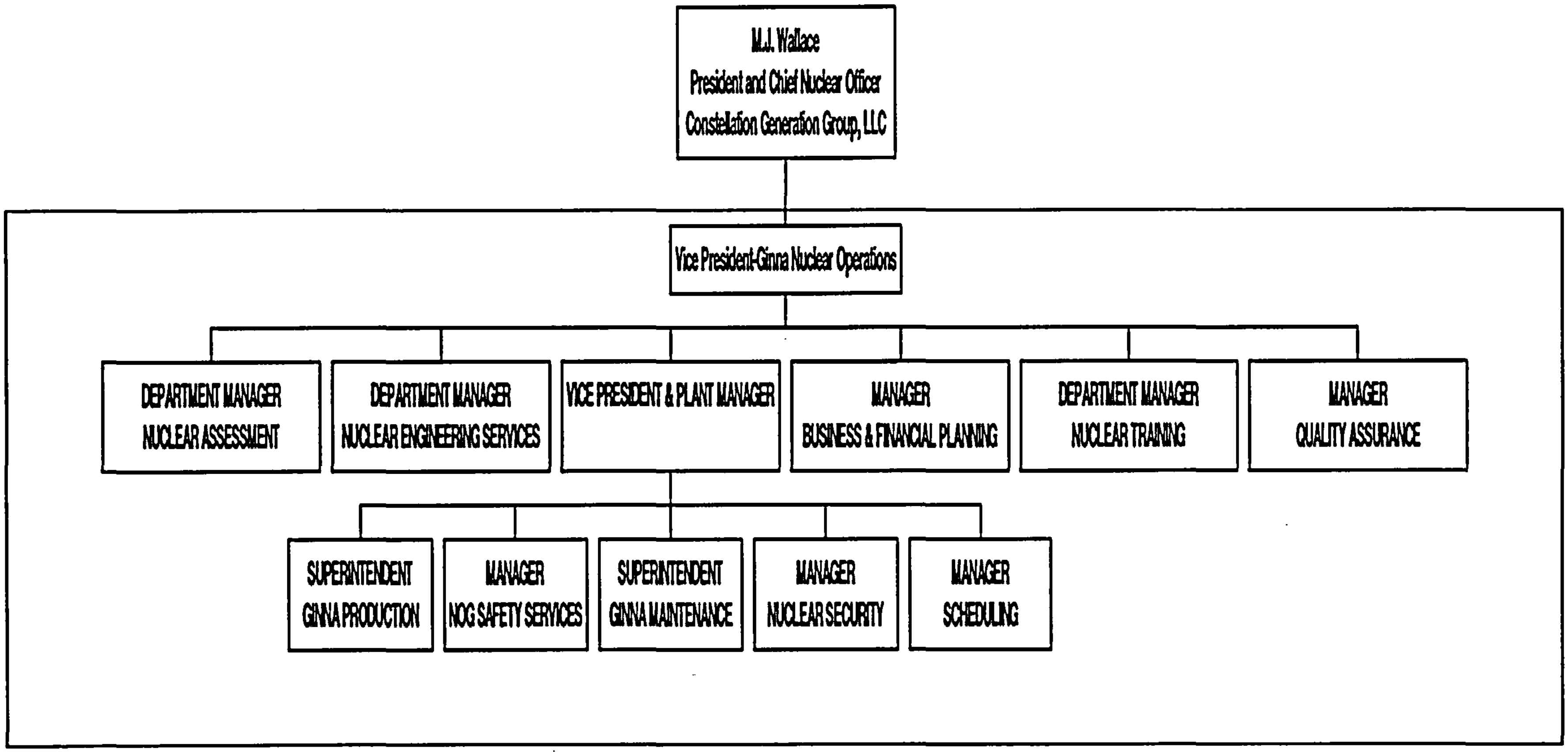
Solely for purposes of Article 5 and Sections 6.12(b) and 10.14:
CONSTELLATION ENERGY GROUP, INC.

By: Mark P. Huston
Name: MARK P. HUSTON
Title: VP - Strategy

Exhibit 3

Exhibit 3

Ginna Station Post Acquisition Organization

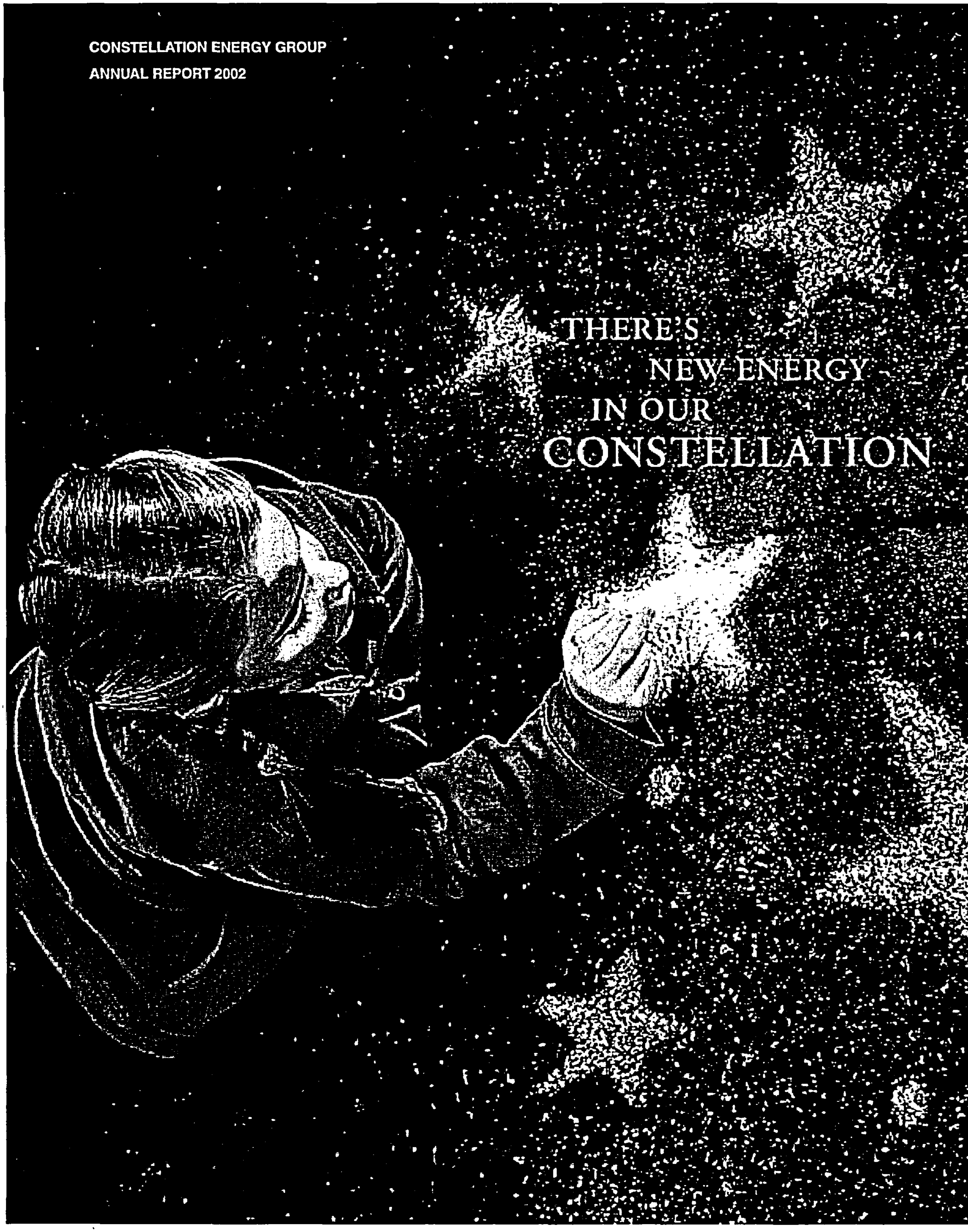


Existing Ginna Station Organization

Exhibit 4

CONSTELLATION ENERGY GROUP

ANNUAL REPORT 2002



Financial Highlights

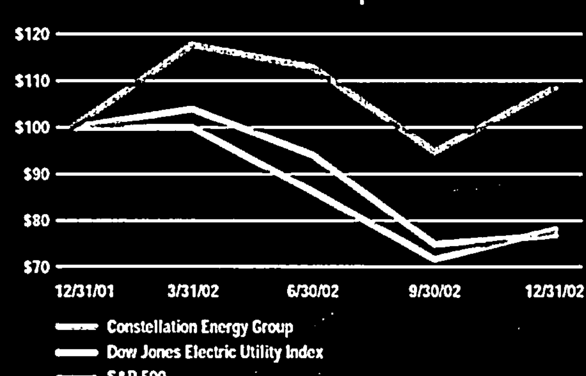
	2002	2001
	(In millions, except per share amounts)	
Common Stock Data		
Earnings per share	$ 3.20	$ .57
Earnings per share before cumulative effect of change in accounting principle	$ 3.20	$ .52
Special items:		
Workforce reduction costs	$ (.23)	$ (.40)
Contract termination related costs	$ –	$ (.87)
Impairment losses and other costs	$ (.11)	$ (.64)
Net gain on the sale of investments and other assets	$ 1.02	$ .02
Earnings per share before cumulative effect of change in accounting principle and special items*	$ 2.52	$ 2.41
Dividends declared per share	$ .96	$ .48
Average shares outstanding	164.2	160.7
Market price per share—year end	$ 27.82	$ 26.55
Financial Data		
Total revenues	$ 4,703	$ 3,879
Income from operations	$ 1,086	$ 358
Net income	$ 526	$ 91
Total assets	$ 14,129	$ 14,109
Current portion of long-term debt and short-term borrowings	$ 437	$ 2,382
Total debt	$ 5,051	$ 5,094
Total common equity	$ 3,862	$ 3,844
Debt (net of cash) to total capitalization	52%	55%
Capital requirement expenditures	$ 923	$ 1,318
Cash available for debt reduction**	$ 582	$ (895)

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

* *Represents a measure that is not determined in accordance with generally accepted accounting principles (GAAP) and should not be considered as an alternative to earnings per share 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.*

** *Represents change in debt (net of cash), excluding net unamortized discount and premium.*

Total Cumulative Return Compared to the Market



Beating the averages. An investment of $100 in Constellation Energy common stock on December 31, 2001 was worth—with dividends reinvested—$108.45 on December 31, 2002. That performance was significantly better than the Dow Jones Electric Utility Index and the S&P 500.

THERE'S NEW ENERGY IN WHAT WE DO

Constellation Energy Group, a Fortune 500 company based in Baltimore, is the nation's leading competitive supplier of electricity to large commercial and industrial customers. We market energy nationally and manage the associated risks. We own and operate a diversified fleet of generation plants throughout the United States. We also deliver electricity and natural gas through the Baltimore Gas and Electric Company (BGE), our regulated utility in Central Maryland. In 2002, the combined revenues of our integrated energy company totaled $4.7 billion.

HERE'S WHAT WE DO

		Our Customers	How We Help Them
Competitive	**Competitive Supply** → Constellation Power Source → Constellation NewEnergy → Fellon-McCord & Associates and Alliance Energy Services	→ Premier wholesale customers—all intensive energy users—distribution utilities with no generation assets including BGE, electric co-operatives, municipalities, and power marketers. → More than 3,000 large commercial and industrial customers throughout North America.	→ Procure energy commodity. → Market energy. → Manage risk. → Provide generation outsourcing and load management. → Offer natural gas and electricity consulting and cost-management services. → Supply natural gas and transportation services.
Competitive	**Generation** → Constellation Generation Group		→ Generate electricity. → Own and operate more than 11,300 megawatts of generating capacity nationwide. → Manage a fleet that is diversified by fuel, geographic location, and technology. → Provide operations, maintenance, gross margin, and integrated partnership management.
Competitive	**Other Energy Services** → Constellation Energy Source	→ Government and large commercial and industrial customers.	→ Provide customized design, construction, and operation of single-site heating, cooling, and cogeneration facilities. → Deliver energy solutions to increase efficiency, reliability, and cost effectiveness.
Competitive	→ BGE HOME	→ Residential and small commercial customers.	→ Provide essential services, including heating, cooling, plumbing, electrical, home improvements, and appliance service.
Regulated	**Energy Delivery** → Baltimore Gas and Electric	→ 1.2 million electric and 600,000 natural gas residential, commercial, and industrial customers.	→ Deliver electricity. → Maintain 250 substations, and nearly 22,500 miles of distribution and 1,300 miles of transmission lines. → Store and deliver natural gas through two peak-shaving plants, nine gate stations, and more than 6,000 miles of gas main.

Our Markets	2002 Highlights
• Competitive wholesale markets in North America. • We handle a significant volume of load in the Northeast and Mid-Atlantic regions, and Texas. • We serve 4,500 megawatts of large commercial and industrial peak load nationally. • Strategic locations where customers have the greatest flexibility in choosing suppliers, including California, Illinois, Kentucky, Massachusetts, Maryland, Maine, Missouri, New York, Ohio, Oklahoma, Oregon, Pennsylvania, Texas, and Canada.	• Achieved what we consider to be the largest market share in a fragmented market. • Expanded our reach into commercial and industrial markets with the acquisitions of NewEnergy and Fellon-McCord and Alliance Energy Services. • Enhanced the energy expertise, strength, and reach of the Constellation Energy team.
• Strategic, competitive markets in North America, including California, Florida, Hawaii, Illinois, Maryland, Michigan, Nevada, New York, Pennsylvania, Texas, Utah, Virginia, and West Virginia.	• Generated 45 million megawatt hours, up from 37 million megawatt hours in 2001. • Decreased operating and maintenance costs by $29 million. • Protected generation gross margins by forward selling and buying 90 percent of the power we'll generate and the fuel we'll need for 2003.
• Government and large commercial and industrial customers with single or multiple locations throughout the United States.	• Awarded contract to design, build and operate $44 million district energy system for downtown Nashville, Tennessee. • Completed and began operating $7 million chilled water plant for The Rouse Company's Las Vegas Fashion Show Mall.
• Homes and small businesses in Maryland.	• Achieved a 95 percent customer satisfaction rating. • Launched residential "smart service" electrical and plumbing product.
• A 2,300-square-mile electric and 800-square-mile natural gas service territory in Central Maryland. • Headquartered in Baltimore since 1816.	• Named a J.D. Power & Associates customer satisfaction leader among eastern utilities. • Provided financial stability with a balanced mix of customer revenues—50 percent residential, 40 percent commercial, 10 percent industrial. • Achieved significant productivity gains. • Ranked among the best—in top 25 percent of regulated utilities—in operating and maintenance costs.

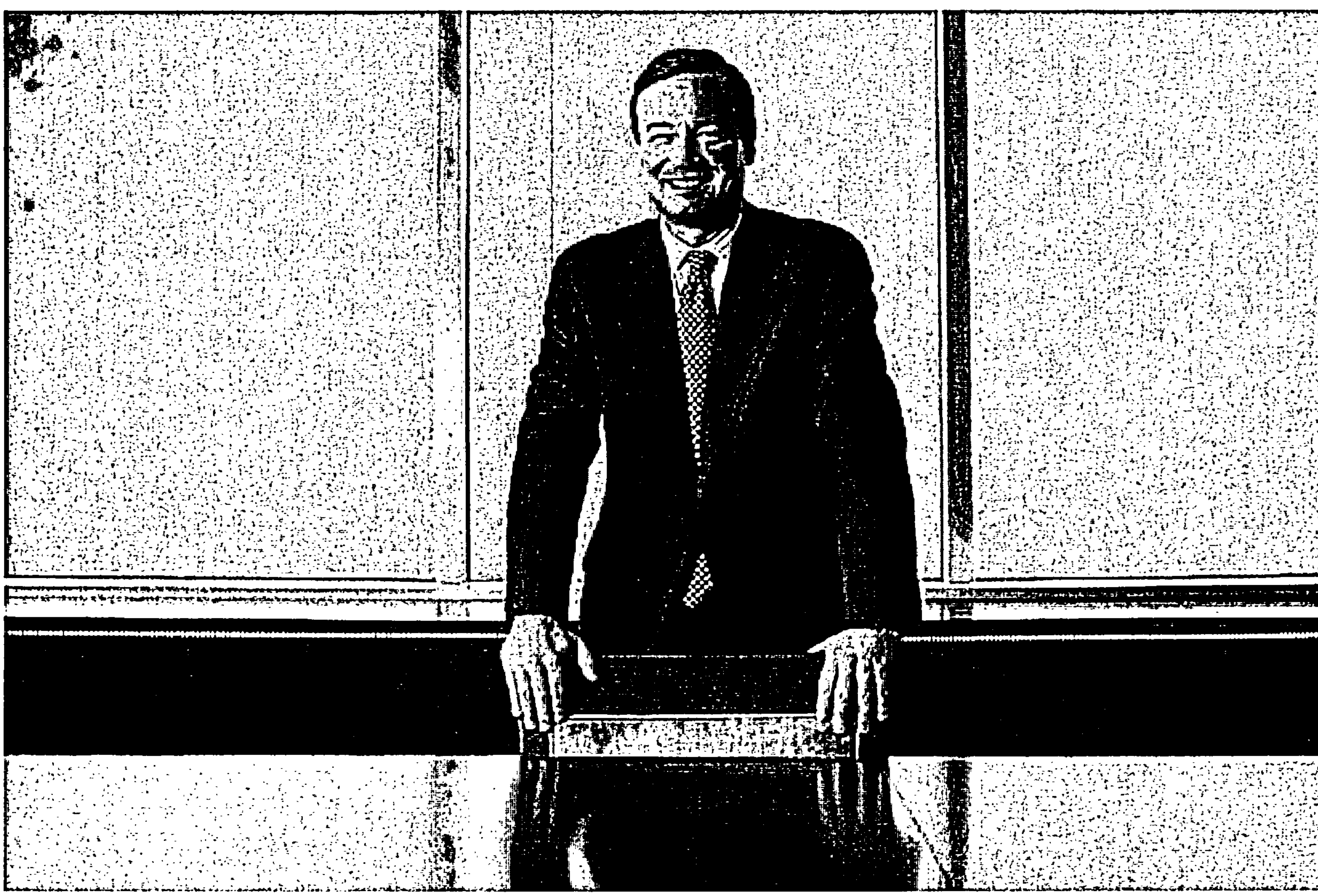
IN OUR CONSTELLATION, WE HAVE

NEW ENERGY

AND IT'S EXCITING

We spent 2002 getting our business in shape. No doubt the environment was worse than we expected, the weather better than expected, and the accounting profession entered the fray to make everything more complicated than expected. Nonetheless, we were steadfast in our determination to deliver, and more importantly, to expand on a strategy in which we have a great deal of confidence.

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



We lived by the idea that we had to earn our right to grow. That meant some tough decisions and hard work. It also meant changing or stopping some of the things we were doing and focusing on what we do best.

The results of our efforts are gratifying: a strong balance sheet, a solid utility business, a fast-growing competitive supply business, and an enhanced focus on our customers. In addition, we continued our leadership in full disclosure and delivered strong financial results.

Solid Earnings Growth

Against a backdrop of lowered earnings expectations in our industry, we reported solid earnings growth. Our reported earnings per share were $3.20 in 2002, compared with $0.57 in 2001. Our 2002 reported earnings include some benefit from special items—primarily non-core asset sales. Our 2001 reported earnings included special items as well—primarily losses due to contract termination and workforce reduction costs. As detailed on the financial highlights page, our earnings for 2002—excluding special items—were $2.52 per share versus $2.41 per share in 2001.

Our 2002 earnings reflect a negative impact of $0.32 for a shift from mark-to-market to accrual accounting for certain parts of our competitive supply business, which was precipitated by changes in the way we do business. This approach was validated by the Emerging Issues Task Force of the Financial Accounting Standards Board issuance of EITF 02-3 late last year.

Despite the implementation of this conservative policy, we were still able to grow our earnings—excluding special items—4.6 percent relative to 2001 earnings per share.

Performing Well in a Challenging Environment

For the year, our stock closed up 4.8 percent over the 2001 closing price. Assuming reinvestment of dividends, our total return to shareholders in 2002 was 8.5 percent. We also doubled our dividend in 2002. And in January 2003, we announced an additional dividend increase of 8 percent, making it an annual rate of $1.04 per share, up from $0.96 per share.

When I look back on the challenges we and the rest of the industry faced in 2002, I'm very proud that we produced such strong financial results and increased the dividend. To see the real strength of our performance, you have to look at what happened beyond the company.

As we all know, 2002 was a very difficult year, especially for the energy sector. The Dow Jones Utility Index was down 27 percent. Valuations were affected by the weak energy business environment, the fact that many companies had earnings decreases year over year, the credibility issues associated with trading and accounting scandals, and a true credit and liquidity crisis for many of our peers.

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

Our mission is to be the nation's leading energy manager and competitive supplier, generating and delivering power and natural gas safely and reliably to our customers while acting in the interests of our communities, employees, shareholders, and the environment.

Sharpening Our Focus

We were one of the first companies to recognize these shifting market dynamics, and we acted quickly.

We increased our focus on generating and selling energy and we sold $708 million of non-core assets—businesses and operations not directly involved in our core business. We continued to invest in our risk management processes and strengthen our control procedures. I believe this has put us in the forefront of the industry. It also has allowed us to avoid many of the issues that befell our competition.

More importantly, we knew that a strong and stable balance sheet would mean the difference between success and failure. By selling non-core assets and extending the maturity of $2.5 billion of debt, we have constructed one of the best balance sheets in the industry and positioned our company to grow.

We constructively renegotiated our contract with the California Department of Water Resources, which allowed us to resolve a significant uncertainty and provide greater visibility into our earnings. We also made great progress in integrating our new acquisitions—Nine Mile Point and NewEnergy—into the Constellation family.

And finally, we sharpened our focus on the right business model. Namely, we worked aggressively to develop further a competitive supply business that balances our generation and regulated distribution businesses and enhances our growth potential.

Where We're Headed

Through our competitive supply platform, we serve as the energy cost manager for utilities and large commercial and industrial customers throughout the country. We moved to expand that business platform with the acquisitions of NewEnergy from AES, and Fellon-McCord and Alliance Energy Services from Allegheny Energy.

We have a significant share of a large but fragmented market. In fact, by our estimates, we are the largest provider of power and energy cost management to wholesale, commercial and industrial customers in deregulated energy markets. And we're seeing great opportunities to continue to grow our share.

We believe we have a strong competitive advantage in our customer relationships, our physical assets, our intellectual capital, and our five years' experience in modeling, evaluating, assuming, and managing the unique risks associated with energy supply and cost management.

Why We'll be Successful

In simple terms, we generate and we sell energy. Most importantly, we meet our customers' energy needs.

One of the key elements of our future success will be this customer focus. Managing the risk and complexity of energy use and cost is a unique skill that is highly valued by our large customer base.

We also will be successful by continuing to focus on operational productivity. Process improvement has become part of our culture, and we have reaped large savings from a number of initiatives throughout the company. With our launch of Six Sigma in 2002, we have institutionalized the notion that we must keep getting better and more efficient at everything that we do.

Finally, we will be successful because we have a business model that allows for strong, stable, and predictable cash flow. We also have a platform that we believe can grow faster than the industry averages. The employees at Constellation worked very hard last year to create this platform in the face of much adversity in the industry. Their commitment, dedication, and focus are the main reasons for our success.

Our Thanks

I want also to pay tribute to two retiring Directors who have made significant contributions to this company for many years. First, Chris Poindexter, my predecessor as Chairman and CEO, has retired from the Board of Directors. His 35 years of service to this company span from the early years of building the Calvert Cliffs Nuclear Power Plant to his courageous stewardship of the company through the deregulation process. His loyalty and impact on Constellation will be a permanent legacy. Bev Byron, retiring in April, has been on the Board of Directors for 10 years. Her insight and commitment to our company have made a real difference.

Sincerely,

Mayo A Shattuck III

Mayo A. Shattuck III
Chairman of the Board, President and Chief Executive Officer
March 7, 2003

Our values will help us in our mission to reach our vision:

- **integrity, teamwork, social and environmental responsibility, and customer focus guide our actions.**
- **speed, accountability, passion for excellence, and creation of value measure our performance.**

We're the energy supplier of choice from coast to coast. Sean Mullen and Sara O'Neill help the New York Sheraton shine with reliable and cost-effective energy. They're members of our competitive energy supply team, which buys the energy for 10 major Starwood Hotels & Resorts properties in New York and California. Starwood is the parent company of the Sheraton, Westin, St. Regis, and W hotel brands.

THERE'S NEW ENERGY IN OUR BUSINESS

We have the building blocks we need to become the first-choice provider for customers seeking energy solutions.

Whether it's a company with sites across the country wanting to deal with one energy company ... or a utility that doesn't own power plants ... or a manufacturer who depends upon a reliable energy supply ... or a Maryland homeowner who wants heat when it's cold, air conditioning when it's hot, and power when the switch is flipped—we have the capabilities to meet their energy needs.

Meeting customer needs and adding value

Competitive energy supply is the growth engine of our company. In 2003, we plan to sell more than 100 million megawatt hours—the 50 million megawatt hours our energy generation business produces, and the more than 50 million megawatt hours that we'll buy from other generators and the market.

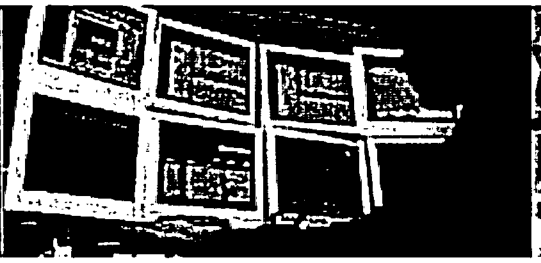
We meet energy needs. And we add value. That includes generating, buying, and supplying energy, managing its use and cost, and developing efficiencies for our wholesale and industrial and commercial customers.

For us, competitive energy supply is a physical delivery business. We take a physical product that we produce or buy, enhance it with value-added services, and deliver it—or provide for its delivery—to customers. These customers include deregulated utilities with no generation assets, electric co-operatives, municipalities, power marketers, and large commercial and industrial customers with sites and companies throughout the United States and parts of Canada.

Diversified generation. Steve Gross is plant manager of our new High Desert power plant, an 830-megawatt, natural gas, combined-cycle plant that will come on line this summer. It's one of California's first major generating plants in more than 10 years. It's also a great strategic addition to our fleet, which is diversified geographically and by fuel source. With High Desert, our total owned generating capacity nationwide will be more than 12,000 megawatts.

No. 1 in competitive energy supply for large customers. We believe our share of this market is the largest of any company serving large commercial and industrial customers. We're estimating that the market will grow from its current 170,000 megawatts to 190,000 megawatts by 2005. Our goal is to increase our leading market share by being among the best at meeting customers' growing needs for energy and energy services.

Reliable delivery. BGE, our regulated, energy delivery business, is the strong and dependable foundation of our company. We deliver energy safely and reliably to 1.2 million electric and 600,000 natural gas customers in Central Maryland. And we do it efficiently while keeping customers happy. BGE ranks among the best—the top 25 percent of regulated utilities—in terms of operating and maintenance costs. In addition, the company was named a J.D. Power customer satisfaction leader among eastern utilities.



Generating best in class

Our beginnings in power generation trace back to one of the first electric companies in the United States. With more than 100 years of experience, we know how to generate electricity. Through the many changes in our industry and business, a constant for us has been to continuously grow and improve.

All of our power plants now sell energy into the competitive marketplace. In 2003, we expect to generate 50 million megawatt hours, the most we've ever generated in one year. And we're aiming to be best in class. By 2004, we expect most of our facilities to be among the best 25 percent of generators in terms of production costs.

Delivering bottom-line productivity

With more than 185 years of energy industry experience, Baltimore Gas and Electric (BGE) has a solid franchise in an economically healthy area.

It has a good customer mix—50 percent residential, 40 percent commercial, and 10 percent industrial—and a steady growth rate with the annual addition of more than 20,000 electric and natural gas customers.

It is also a productivity leader. In 2002, BGE—along with our generation business—achieved process improvements that helped the company save $68 million. In 2003, it will be taking its Achieving Operational Excellence program to the next level through Six Sigma, a disciplined approach to continuous improvement. BGE and other parts of our company will be using Six Sigma to focus on reducing costs, improving quality and reliability, lowering administrative and operational cycle times, and improving overall customer satisfaction.

Putting us in a good position

We are well positioned. Through the strategic sale of non-core assets and decisive action in the capital markets, we now have one of the strongest balance sheets in our industry. In 2002, we reduced our net debt by $500 million and our debt-to-capital ratio to 52 percent. We plan on reducing net debt by another $400 million in 2003.

Our people are the real source of our new energy. They have the expertise and ability to execute our strategy, and the drive to make us the first-choice provider for customers seeking energy solutions.

THERE'S NEW ENERGY IN OUR REACH

We have the reach we need to become the first-choice provider for customers seeking energy solutions.

Our reach gives us access to deregulated markets and to customers who can choose their energy suppliers. It also gives us access to the disciplined growth that is part of our strategy.

We can deliver energy and value-added services to customers throughout North America. Our national fleet of generating plants and our competitive energy supply operations are strategically located in and near deregulated markets across the United States.

The Fashion Show retail center in Las Vegas is cool. With 250 tenants and a million square feet of common space, that's important to The Rouse Company development director Sharon Bair. We developed, implemented, and now operate the center's air conditioning system—a chilled-water plant that saves The Rouse Company property a cool $500,000 a year in energy costs.

Our reach extends into all areas of a customer's operations. At Boston University, we serve more than 700 accounts by supplying electrical energy to dormitories, classrooms, laboratories, athletic facilities, outdoor lighting, and many other areas of its campus along the banks of the historic Charles River.

Our reach extends to the bottom line. As the preferred supplier of electricity to the Illinois Manufacturers' Association (IMA), we have helped more than 500 of its member companies save approximately $25 million in energy costs since 1999. Jim Belden (left), a sales and marketing director with our competitive energy supply business, and Kurt Wiebe, vice president of the IMA, are part of the team that has helped make that happen. The key has been delivering on our promise—supplying cost-efficient energy with excellent customer service.

Our reach also extends to the skies. When Lockheed Martin needed a reliable supply of low-cost energy and a way to track its energy use, we provided the solution.

Throughout the United States

Our reach helps make us the largest supplier of competitive power to utility, municipal, and commercial and industrial customers throughout the United States.

We provide energy and services directly to large commercial and industrial customers. We also provide energy and services to wholesale customers who then distribute the energy to their own customers.

In the Northeast, our energy reaches into New York, New Jersey, Massachusetts, Rhode Island, New Hampshire, and Maine. That reach allows us to be one of the largest suppliers to companies like National Grid.

Our reach also allows us to serve The Rouse Company, which has more than 50 upscale retail properties totaling 45 million square feet in major markets throughout the United States. It is one of the nation's premier real estate development and management companies. With the energy services we provide, The Rouse Company can view and monitor energy costs, usage, efficiency, and other energy statistics for all its properties.

In Maryland, our reach extends to 1.2 million electric and 600,000 natural gas customers of Baltimore Gas and Electric. Our regulated business ensures that the energy the region needs is delivered safely and reliably.

Gaining high-value customer relationships

We improved our reach during 2002 with the acquisitions of NewEnergy from AES, and Fellon-McCord and Alliance Energy Services from Allegheny Energy. Those companies came with key expertise and resources, and some high-value customer relationships. They also came with offices strategically located in states where customers have the most flexibility in choosing energy suppliers. Those states include California, Illinois, Kentucky, Maryland, Massachusetts, New York, Ohio, Oklahoma, Pennsylvania, and Texas.

All along the energy value chain

Our reach also extends across the energy value chain. Between the creation and consumption of energy, there is a long chain of valuable transactions. Its many activities and processes include:

- purchasing the fuel to produce energy, generating energy, and delivering energy to customers who use it.
- selling and delivering energy to wholesale customers who then sell it to their own retail customers who use it.
- serving as an energy procurement and management function for large commercial and industrial customers.
- selling energy to other energy marketers who use it to meet their customers' needs.

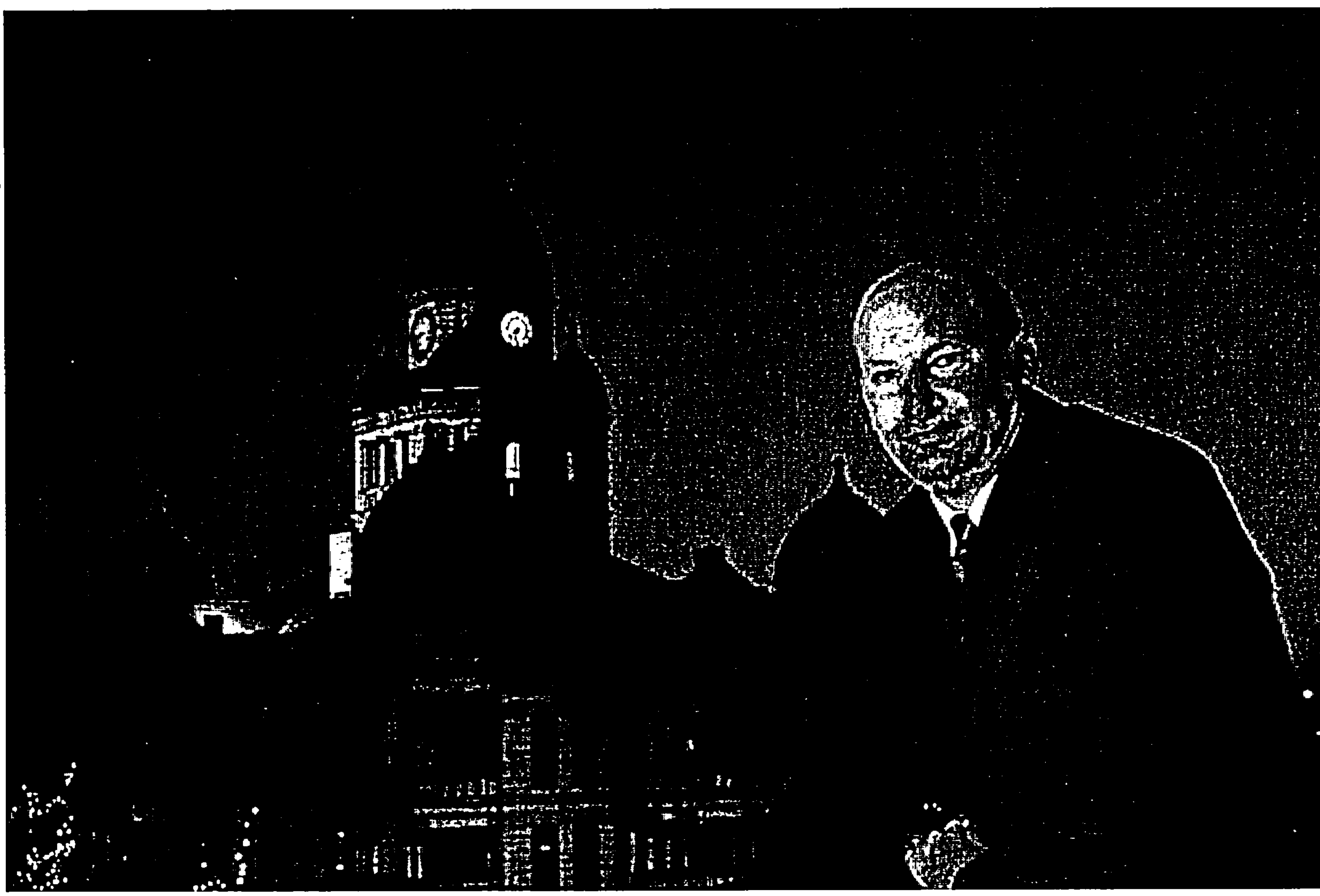
THERE'S NEW ENERGY IN OUR APPROACH

We have the approach we need to become the first-choice provider for customers seeking energy solutions.

Our approach is basically how we run our business. We generate and sell energy, we focus on customers, and we manage risk.

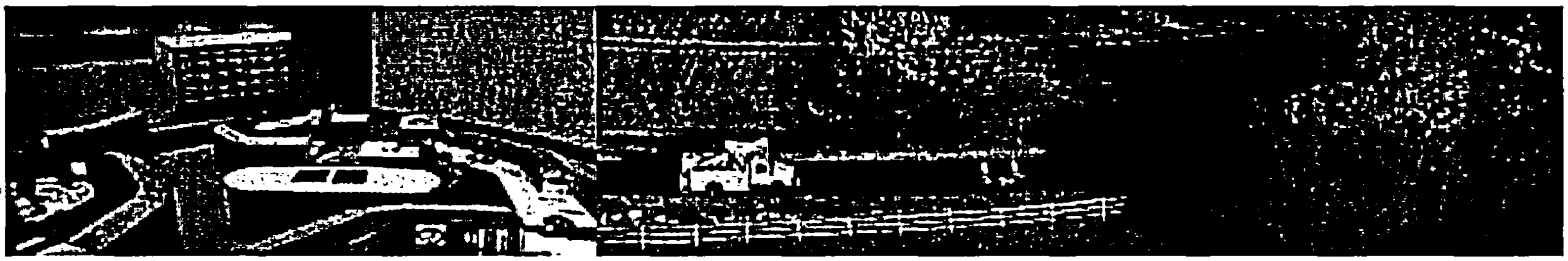
The approach we take in generating and selling energy starts with a balanced strategy. Operating in both regulated and deregulated business environments provides us stable earnings with good growth opportunities.

We help Denton, Texas get the energy it needs. In Denton—home to the University of North Texas and a 106-year-old courthouse made of Texas limestone—we work with Glenn Fisher, Assistant Director with Denton Municipal Electric, to help make sure the lights stay on for the city's nearly 85,000 residents. We handle Denton's full requirements for energy—managing its power purchase agreements, scheduling delivery of energy, buying the energy, and settling the accounts.



Getting our energy to where it's needed, when it's needed. PJM is the largest competitive wholesale electricity market in the world. It is responsible for the transmission of bulk energy through seven eastern states and the District of Columbia. Recognized as the premier regional transmission organization in the United States, PJM has about 200 members—and we've been a part of it since its inception. With more than 6,000 megawatts of generating capacity in the region, we've gained skills and expertise in transmitting large amounts of energy through PJM. Now we're using our skills and expertise in other areas of the country where we serve large customers.

Providing energy ... and more. National Grid owns five distribution utilities serving 3.2 million electric customers in New York, Massachusetts, Rhode Island, and New Hampshire, and 540,000 natural gas customers in New York. In conjunction with deregulation, the company sold its generation. So now it must buy most of the energy it delivers. In addition to being one of National Grid's largest suppliers—providing 3,000 megawatts of power—we also handle many of the operational, administrative, and risk management aspects of serving the company's load requirements and administering its power purchase agreements.



Even greater balance

We sell a mix of energy that we generate and that we purchase. That balance of owned and contracted generation gives us greater flexibility and helps diversify risk.

Increasing our participation along the energy value chain gives our strategy even greater balance. We are disciplined and focused on opportunities that offer growth potential or stable and predictable earnings.

Customers are at the heart of our business

Our core skills are generating, purchasing, delivering, and selling energy. But our core mission is meeting customers' energy needs. Our customers have complex needs that aren't easily met by the standard, one-size-fits-all, large blocks of power that are typically traded in the wholesale energy markets.

We analyze energy usage patterns and suggest alternative production and operational possibilities to lower energy costs. We also plan, generate, buy, and manage energy—often acting as an extension of our customers' administrative and procurement functions.

In short, we sell energy and value-added, cost-management services. This requires a special expertise. And our customers often don't want to invest what's needed to build and maintain that capability in-house.

Managing risk conservatively

Risk management is in our DNA. Our combination of skills differentiates us from the rest of our industry.

From our unique relationship with Goldman Sachs from 1997 to 2001, we've gained skills and expertise in risk management, economic forecasting, and modeling. From our more than 185 years in the utility business, we've gained skills and expertise in customer service, demand forecasting and management, and energy generation, transmission, and delivery.

Added to that is our intellectual capital—built with five years of experience evaluating, assuming, and managing the unique risks associated with energy cost management and load-shaping. We believe that experience is what differentiates us from everyone else.

We evaluate and manage the risk our customers want to minimize. And we take a distinctly conservative approach. We sell energy—either producing it ourselves or buying it from others—and we physically deliver it along with value-added services to our customers.

Providing these services also earns a premium. It's an important part of our approach that enables us to grow earnings, even at a time when other energy providers are struggling.

Bette has found a new home with us. She had been hanging — or should we say flying — around our Crane Power Plant on the Seneca Creek in Baltimore County. She was looking for a place to raise a family. Naturally, we agreed to help her find a home. The plant site is an ideal habitat, with plenty of water and marshland. We first learned about Bette from the Center for Conservation Biology at the College of William & Mary. The Center rescued the peregrine falcon from a poorly located nest when she was just a chick, and it has tracked her location ever since. Following the Center's directions, we provided a structure in which Bette could build a nest. She was impressed and moved right in. Now we're hoping to welcome her new chicks sometime this spring.

THERE'S NEW ENERGY IN OUR COMMUNITIES

Being thoughtful and caring stewards of our environment and communities is an important part of our mission. Social and environmental responsibility is one of our foundational values.

We benefit from doing business in the communities where our employees and customers live. In turn, the communities should benefit from our presence. Being a good corporate citizen is the right thing to do. It also makes good business sense.

Our environmental stewardship

All of our efforts center on our commitment to helping meet the nation's energy needs, while also decreasing the environmental impact of energy production. The U.S. Department of Energy's Climate Challenge Program is the world's largest and most successful initiative on global climate change. It features voluntary individual utility programs and industry-wide initiatives to reduce, avoid, or sequester greenhouse gases. And we're an active participant.

Since 1991, we've prevented the release of more than 40 million tons of carbon dioxide emissions per year by expanding our nuclear plant capacity, running our fossil-fueled plants more efficiently, and using less fuel. As a partner in the U.S. Environmental Protection Agency's Energy STAR Buildings Program, we've also conserved enough energy to prevent the release of almost 100,000 tons of carbon dioxide. Our goal is to continue reducing emissions of carbon dioxide per megawatt of electricity produced.

The diverse fuel mix we use to generate electricity also supports our environmental stewardship. More than half of the power we generate in 2003 will come from emission-free nuclear power, with the rest from coal, oil, gas, and renewable sources. We're also ahead of the industry by installing selective catalytic reduction technology at our two largest coal-fired power plants, allowing us to remove 90 percent of ozone-contributing gases.

Kennedy Krieger Institute. The internationally recognized Kennedy Krieger Institute is dedicated to helping children from around the world cope with disorders of the brain and achieve their full potential by participating as fully as possible in family, school, and community life. A pioneer in special education, research, and training, Kennedy Krieger's teams of specialists use a family-centered approach to ensure quality care.

The Chesapeake Bay Foundation. As the foremost conservation organization dedicated solely to saving the Chesapeake Bay, the foundation's motto, *Save the Bay*, defines its mission throughout the 64,000-square-mile watershed. Its nationally recognized environmental education program works to prevent pollution, restore habitat, and increase fisheries.

Living Classrooms Foundation. Offering hands-on education and job training programs, Living Classrooms motivates diverse, at-risk students to succeed academically, in the workplace, and in their lives. With an emphasis on math, science, language arts, history, economics, and ecology, the programs provide opportunities for students to apply the lessons and techniques to maritime settings, community revitalization projects, and other challenging environments.

The real winners of the Constellation Energy Classic.

Renewable energy

We have ownership interests in 19 renewable energy projects throughout the country. These plants use solar, geothermal, biomass, hydro, and waste coal energy sources to produce power. Also, the U.S. Department of Energy's National Energy Technology Laboratory selected us as one of five companies to manage a national Biomass & Alternate Methane Fuels Energy Savings Performance Contract for federal facilities.

Our efforts have received numerous awards, including U.S. Environmental Protection Agency WasteWise Partner of the Year, U.S. Department of Energy Clean City Award, and Clean Air Partners Award for Ozone Action Days Program.

Our community commitment

We have a commitment to community partnerships. In 2002, we contributed $4 million to educational, environmental, and economic development programs.

Education is the foundation of personal and economic growth. When individuals are gainfully employed and live productive lives, there are many benefits—to the individuals, their communities, businesses within those communities, the quality of life, and the overall economy.

So our support of education goes primarily to two basic types of programs. We support programs that provide students with the skills they need to enter the workforce when they finish school. We also support programs that provide opportunities for students to develop into resourceful leaders, informed voters, and knowledgeable consumers—all with understanding and respect for one another.

In addition, we encourage our employees to join with us in financially supporting institutions of higher learning through our Matching Gifts Program.

Our economic development support focuses on community revitalization and efforts to promote job creation and retention. We also support various arts and cultural programs.

Constellation Energy Classic

We're using our new sponsorship of the Constellation Energy Classic—a professional golf tournament—to add to our support of our communities and the environment. More than 80 golfers from the Champions Tour—formerly known as the Senior PGA TOUR—will participate in this September event. All proceeds will be donated to three charities.

The Kennedy Krieger Institute and Living Classrooms Foundation both will receive funds to help in their work providing children with needed care and preparing students to become productive members of our communities. The Chesapeake Bay Foundation will receive funds to support its efforts to preserve and enhance the health and vitality of Chesapeake Bay.

THERE'S NEW ENERGY IN OUR FUTURE

A Conversation With Mayo A. Shattuck III

"Constellation Energy is an exciting place to be right now. Our vision is to be the first-choice provider for customers seeking energy solutions in the complex and changing energy marketplace. That's a big order. But we have a strategy that provides a clear path to reaching our vision. We just need to execute, and that's how I'll be spending most of my time."

Mayo Shattuck

What do you see as our major accomplishments in 2002 and our major challenges for 2003?

Our promise last year was that we would focus on crisp execution and earn the right to grow. I am very proud to report that we delivered on those promises. We met or exceeded our guidance to Wall Street for the last five quarters, something very few of the energy companies we monitor managed to do.

Perhaps more important, we put ourselves in the position of being able to control our own destiny as our industry continues to evolve. Recognizing that a strong balance sheet would mean the difference between success and failure, we acted aggressively to improve our balance sheet by selling $708 million in non-core assets and issuing $2.5 billion of long-term debt. These actions have given us one of the best balance sheets in the industry.

And finally, we sharpened our focus on the right business model, namely, serving as the energy cost manager for utilities and large commercial and industrial customers. We moved to expand that business platform with the acquisitions of NewEnergy, and Fellon-McCord and Alliance Energy Services. The balance in earnings growth potential provided by a large scalable competitive supply business promises to deliver more stable and predictable earnings and cash flow.

In 2003, we must continue to earn the right to grow. Doing that will require executing on our plan—growing our competitive supply business, achieving productivity gains, maintaining a disciplined approach to deployment of capital, and further enhancing our customer focus.

We're focusing on the competitive energy supply business while other companies are leaving that marketplace. What makes our strategy the right one?

There's no question that some companies in the competitive energy marketplace have made major errors. Some have left and others are now scrambling for their very existence. Overall, the competitive landscape has changed dramatically.

What has not gone away—and what will not go away—is the customer need for energy and energy services. We estimate that the market in which customers can choose their energy suppliers is currently 170,000 megawatts, and we believe it will grow to 190,000 megawatts by 2005. Right now, we're the nation's largest competitive supplier of energy and energy-related services to utility, municipal, commercial, and industrial customers. Our goal is to increase our market share.

The energy cost management services we provide require a level of expertise that our customers do not possess and don't want to build in-house. We differentiate ourselves by understanding our customers' needs, structuring contracts that meet those needs, pricing them appropriately, and becoming an integrated component of our clients' operations. Said simply—we manage our partners' energy needs.

It's a fragmented market, and we see a real opportunity to grow this business both organically and through niche acquisitions as others leave the business.

Constellation Energy does not face the problems many other energy companies do. Why is that?

Some companies are suffering from self-inflicted problems. We have avoided those pitfalls. We have a balanced strategy that combines the strong, predictable earnings of our regulated business with the growth of our competitive supply business. We generate and sell energy along with value-added services to customers. Ours is a physical delivery business—you can clearly see what we're doing.

On top of that, our performance has been key. We recognized the reality of the competitive energy marketplace early on, and we took decisive action. The results give us some significant advantages—a strong balance sheet and cash flow, solid investment-grade credit ratings, an integrated management team, and risk management expertise—all of which position us

to achieve long-term earnings growth. Add to that our focus on integrity, best practices in full disclosure, and our smart, disciplined approach to the use of capital, and you can see why we succeeded where others may have faltered.

In January, we increased our dividend by 8 percent. What is our dividend policy?

When I look back on the challenges we faced in 2002, I'm very proud that we produced the strong financial results that allowed us to improve our balance sheet, invest in growth opportunities at attractive returns, and raise our dividend. Very few companies in our sector can make the same claim.

Our goal is to provide a competitive total return to our shareholders through a combination of stock price appreciation and dividends. We believe strong earnings growth will drive stock price appreciation, and we plan to supplement that return with a sustainable dividend.

You say we have the right people in the right positions. What core competencies do we need on our management team?

If you look at the members of our leadership team, you'll see their backgrounds are both impressive and diverse. Every person is on the team because they are strong leaders, top-tier performers in their fields, and they bring to the table the right mix of skills and experience we need to be successful in this business. More importantly, they're here because they are solid team players whose particular talents complement the others.

What makes us best in class in terms of financial disclosure?

One of my first priorities last year was to foster a new culture of openness in which we provide best-in-class disclosure and better insight into how we make money.

We've made a substantial investment in people, as well as in systems to help us track and understand our business and the direction in which it's headed. As a result, we are able to give accurate guidance on and present detailed financial models of how we make money, giving investors and analysts the information they need to appropriately value our company.

What makes us risk management experts?

We have intellectual capital and expertise in this area that few can claim. We developed our skills in economic forecasting and modeling and established a world-class risk management operation during our association with Goldman Sachs. Our expertise in energy demand forecasting and management, and generation, transmission, and distribution, comes from more than 185 years in the utility business.

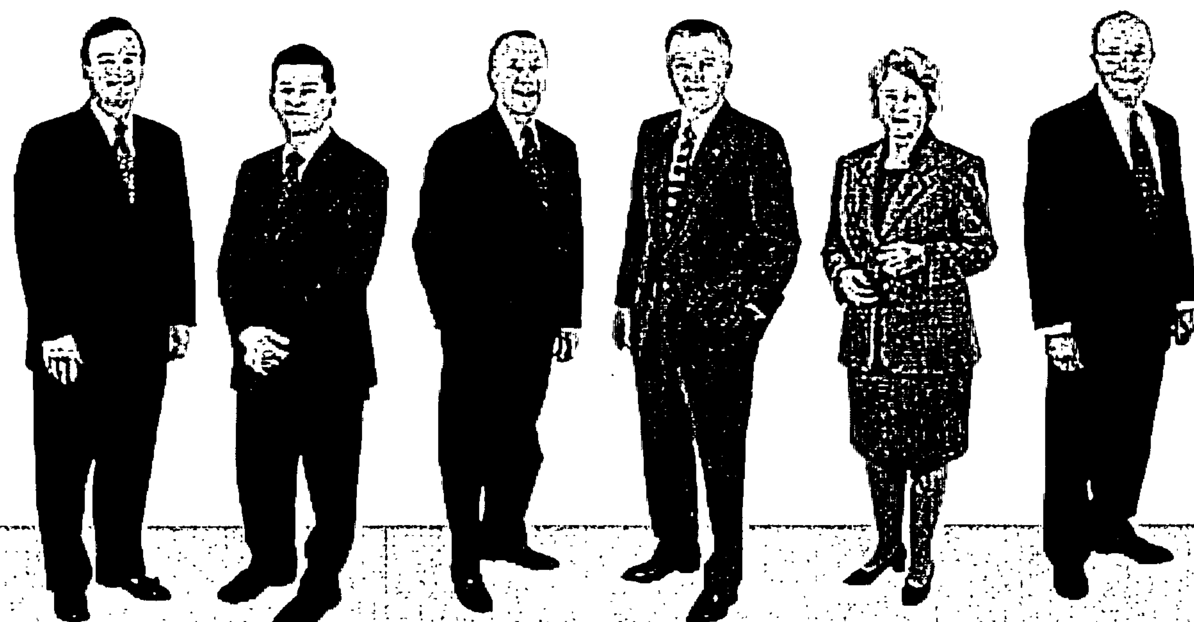
We've spent the last five years evaluating, modeling, assuming, and managing the unique challenges associated with the complex energy needs of our customers. We have continued to invest both in personnel and systems to rigorously test and optimize the way we quantify and manage risk.

Risk management is also a fundamental component of the management of this company. We have a chief risk officer who reports directly to me, senior managers experienced in managing risk, and a very programmed process structured with strong internal and external controls. I believe all of this puts us at the forefront of the industry.

How will you spend most of your time in 2003?

My focus will be on executing our strategy. We're a national company now with operations all over the country. And there are a lot of opportunities to take advantage of good earnings drivers. We have experienced personnel focused on operational excellence. If we execute our strategy, we'll be able to deliver some very significant earnings growth.

Board of Directors



Mayo A. Shattuck III
Chairman, President and Chief Executive Officer, Constellation Energy Group
Age 48
*Director since 1994**

Douglas L. Becker
Chairman and Chief Executive Officer, Sylvan Learning Systems, Inc.
Age 37
*Director since 1998***

James T. Brady
Managing Director, Mid-Atlantic of Ballantrae International, Ltd.
Age 62
*Director since 1998**

Frank P. Bramble, Sr.
Vice Chairman, MBNA Corporation
Age 54
Director since 2002

Beverly B. Byron
Former Congresswoman, U.S. House of Representatives
Age 70
*Director since 1993***
(Retiring April 2003)

Edward A. Crooke
Retired Vice Chairman, Constellation Energy Group
Age 64
*Director since 1988***

Committees of the Board

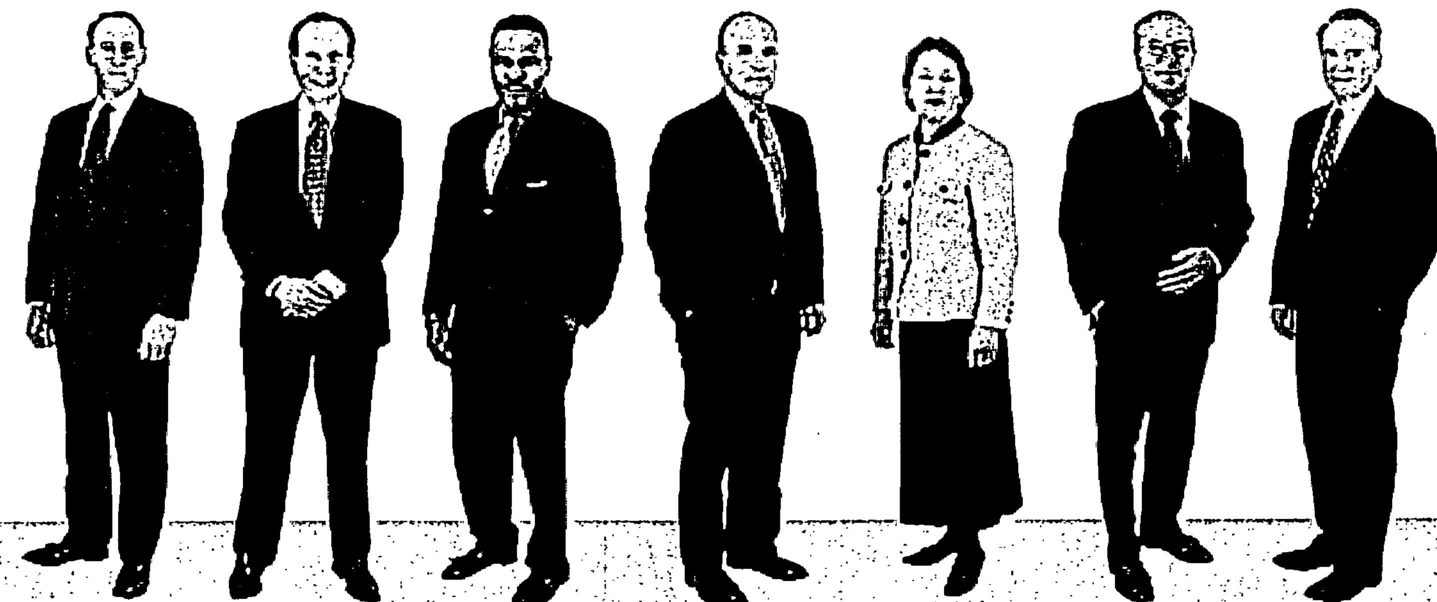
Executive Committee
- Mayo A. Shattuck III, Chairperson
- Frank P. Bramble, Sr.
- Edward A. Crooke
- Edward J. Kelly III
- Robert J. Lawless

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

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

Committee on Nuclear Power
- James R. Curtiss, Chairperson
- Beverly B. Byron
- Edward A. Crooke
- Roger W. Gale

Nominating and Corporate Governance Committee
- Michael D. Sullivan, Chairperson
- Douglas L. Becker
- Frank P. Bramble, Sr.
- Edward J. Kelly III
- Robert J. Lawless



James R. Curtiss, Esq.
Partner, Winston & Strawn
Age 49
*Director since 1994***

Roger W. Gale
Partner, GF Energy, LLC
Age 56
*Director since 1995**

Dr. Freeman A. Hrabowski III
President, University of Maryland Baltimore County
Age 52
*Director since 1994***

Edward J. Kelly III
Chairman, President and Chief Executive Officer, Mercantile Bankshares Corporation
Age 49
Director since 2002

Nancy Lampton
Chairman and Chief Executive Officer, American Life and Accident Insurance Company of Kentucky
Age 60
*Director since 1994***

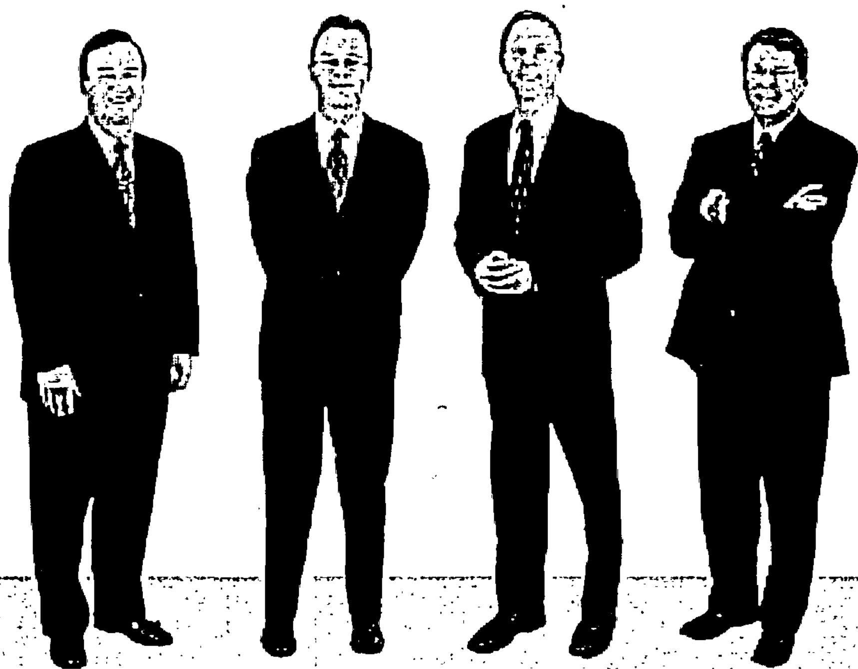
Robert J. Lawless
Chairman, President and Chief Executive Officer, McCormick & Company, Inc.
Age 56
Director since 2002

Michael D. Sullivan
Chairman, Life Source, Inc.
Age 63
*Director since 1992***

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

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 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.



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

48, joined Constellation Energy as President and CEO, and was elected Chairman of the Board in July 2002. From 1999 to 2001, he was Co-head of Deutsche Bank's Global Investment Bank and a member of the Board of the Bank's Global Corporates and Institutions Division. Other positions held while at Deutsche Bank included Chairman of the Board of Deutsche Banc Alex. Brown, CEO of the Private Client and Asset Management Group Americas, and Global Head of the Private Banking Division. Previously he was Vice Chairman of Bankers Trust Corporation and President of Alex. Brown, Inc.

Thomas V. Brooks
President, Constellation Power Source

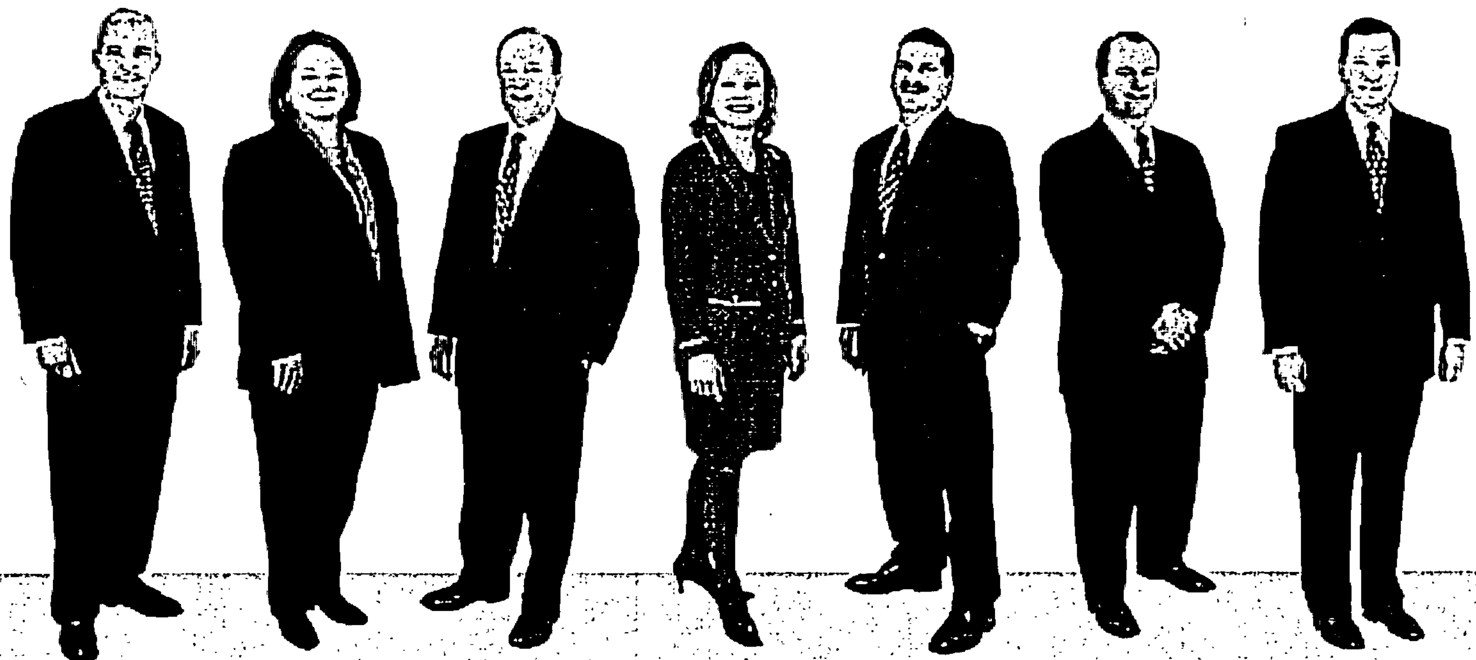
40, joined Constellation Energy in 2001 as Vice President, Business Development & Strategy, and was elected to his current position in 2001. Prior to this, he was Vice President, Goldman Sachs, working with Constellation to develop its power marketing business; previously served as director, Enron Capital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

Frank O. Heintz
President and Chief Executive Officer, BGE

59, joined BGE* in 1996 as Vice President, assuming leadership of its Gas Division in 1997; elected Executive Vice President, BGE Utility Operations Group in 1998, 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 Baltimore City Councilman.

Michael J. Wallace
President, Constellation Generation Group

55, joined Constellation Energy in 2002. Prior to this he was co-founder and Managing Director, Barrington Energy Partners, LLC, an energy industry strategic consulting firm. Previously he held several executive positions at Unicom/ComEd of Illinois, including Senior Vice President and Vice President. He also served as its Chief Nuclear Officer and led its nuclear fleet.



Thomas F. Brady
Senior Vice President, Corporate Strategy & Development

53, joined BGE* in 1969; became Assistant Treasurer–Assistant Secretary in 1983; elected Vice President, Accounting & Economics in 1988; Vice President, Customer Service & Accounting in 1991; Vice President, Customer Service & Distribution in 1993; Vice President, Retail Services in 1998; Vice President, Corporate Strategy & Development in 1999; and assumed his current position in 1999.

E. Follin Smith
Senior Vice President & Chief Financial Officer

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

Paul J. Allen
Vice President, Corporate Affairs

51, joined Constellation Energy in 2001. Prior to this he was Senior Vice President and Group Head–Ogilvy Public Relations, managing its energy and environment practice. Previously he served as senior staff member at 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.

Kathleen A. Chagnon
Vice President, General Counsel and Secretary

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

John R. Collins
Vice President and Chief Risk Officer

45, 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

39, 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.

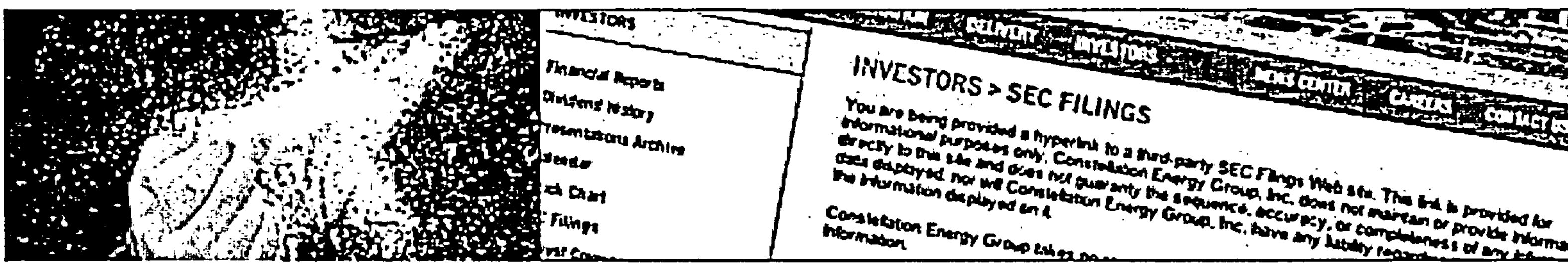
Marc L. Ugol
Vice President, Human Resources

44, joined Constellation Energy in 2002. Prior to this he was Senior Vice President of Human Resources at Tellabs, Inc., a global telecom manufacturer. Previously, he held human resource management positions at Platinum Technology, Inc., and System Software Associates, Inc.; and spent 14 years with Amoco Corporation in a variety of management positions, including four years as Director of Human Resources for Amoco Norway based in Stavanger, Norway.

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

WE'RE TAKING THE NEXT STEP.

UNDERSTANDING OUR FORM 10-K



One of our priorities at Constellation Energy is to provide you with clear, more understandable information about our company.

We are a leader in full disclosure.

Five years ago, we were among the first major corporations to use plain English to make our financial information easier to understand.

Now, we're taking the next step.

The information on the next few pages is intended to help make our Form 10-K—our annual report required to be filed with the Securities and Exchange Commission—more welcoming and less complex. Very simply, we want you to know and understand what we do.

It's all about giving investors the information they need.

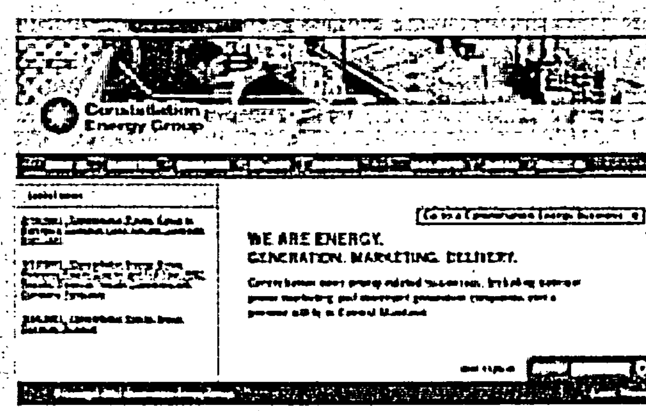
It's our continued leadership in providing information that all shareholders can better understand.

FULL DISCLOSURE AND TRANSPARENCY

It has never been more important for companies to provide investors better insight into their business and how they make money. The buzzword you often hear today is "transparency." At Constellation Energy, we view it as a priority to offer our investors the information they need to understand what drives our business.

This year we've chosen to include the complete Form 10-K in our 2002 Annual Report. The Form 10-K is a standard document that all U.S. publicly held companies are required to file annually with the Securities and Exchange Commission (SEC). The document is available to investors and anyone else who wishes to review it.

While the Form 10-K is complex, it is where investors can find detailed and comprehensive information about a company and its operations. To help make the financial information in this document easier for you to find and understand, we have developed a Form 10-K overview and glossary of terms, both of which follow on the next few pages.



You'll find all of our SEC filings right on the Investor page of our Web site—constellation.com.

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 the details on our board of directors and executive officers and their compensation.
- **Part IV:** a listing of exhibits, certain executive and board of directors' signatures, and executive officer certifications.

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 energy delivery utility Baltimore Gas and Electric Company, and our other nonregulated businesses. Also included is information about environmental matters, employees, properties, and executive officers.

Here's Where You Look in Part I		Here's What You'll Find
Item	**Section**	
Business	Overview	• Company description and brief background. • Operating segment details.
	Merchant Energy Business	• Business description. • Discussion of fuel sources we use to generate electricity. • Discussion of our competition. • Merchant energy operating statistics for the last five years.
	Baltimore Gas and Electric Company	• Business description broken down between electric and gas. • Electric and gas operating statistics for the last five years.
	Other Nonregulated Businesses	• Descriptions of our other nonregulated businesses.
	Environmental Matters	• Discussion of the environmental matters affecting the company.
	Employees	• Number of employees. • Union representation and labor contract status.
	Properties	• Generating plant location, ownership, and size details. • Offices and facilities we own and lease.
	Executive Officers of Constellation Energy	• Executive officers' names, ages, current positions, and recent experience.

PART II: OUR FINANCIAL PERFORMANCE

Part II contains management's discussion of our results of operations and financial condition. It compares 2002 results to 2001, and 2001 results to 2000. 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		Here's What You'll Find
Item	**Section**	
Market for Registrant's Common Equity and Related Shareholder Matters		Dividend information and quarterly dividend and stock prices for the last two years.
Selected Financial Data		Summary of operations and financial conditions of Constellation Energy and Baltimore Gas and Electric, and financial statistics for the past five years.

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		Here's What You'll Find
Item	**Section**	
Management's Discussion and Analysis of Financial Condition and Results of Operations	Introduction	Overview of our company.
	Critical Accounting Policies	Description of our accounting policies that are most complex and subjective in portraying our financial condition and results.
	Significant Events 2002 and 2001	Discussion of the significant events in 2002 and 2001 that impacted our company.
	Strategy	Discussion of our overall strategy, which focuses on maintaining a balance of stability and growth.
	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.
	Results of Operations	The discussion of our earnings broken down as follows: Our overall net income. Our net income for our merchant energy business. Our net income for Baltimore Gas and Electric's regulated electric and gas businesses. Our net income for our other nonregulated businesses. Our non-operating income and expenses.
	Financial Condition	Cash flow details for the last three years. Credit ratings for Constellation Energy and Baltimore Gas and Electric.
	Capital Resources	Capital requirements for the last three years and estimates for the next two years. How we expect to fund our capital requirements. Financial obligations over the next five years and beyond.
	Market Risk	Discussion of our market risk, including interest rate risk, commodity price risk, credit risk, and equity price risk. Discussion of how we manage those risks.

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 auditor reports on our financial information.

Here's Where You Look in Part II		Here's What You'll Find
Item	**Section**	
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 Senior Vice President & Chief Financial Officer E. Follin Smith.
	Report of Independent Accountants	→ External audit report of PricewaterhouseCoopers LLP.
	Consolidated Statements of Income	→ Revenue, expenses, income, and earnings for the last three years. (separate statements included for Constellation Energy and Baltimore Gas and Electric)
	Consolidated Balance Sheets	→ Assets, liabilities, and equity for the last two years. (separate statements included for Constellation Energy and Baltimore Gas and Electric)
	Consolidated Statements of Cash Flows	→ Cash flows from operating, investing, and financing activities for the last three years. (separate statements included for Constellation Energy and Baltimore Gas and Electric)
	Consolidated Statements of Common Shareholders' Equity and Comprehensive Income	→ Changes in common stock, retained earnings, and other comprehensive income for the last three years.
	Consolidated Statements of Capitalization	→ Long-term debt, preference stock, and common shareholders' equity details for the last two years.

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		Here's What You'll Find
Item	**Section**	
Notes to Consolidated Financial Statements	Note 1. Significant Accounting Policies	→ Accounting methods that we use. → Effect on earnings of applying fair-value accounting to stock options and stock grants. → Recently adopted or issued accounting rules established by standard setters.
	Note 2. Impairment Losses, Workforce Reduction, Contract Termination, and Other Special Items	→ Workforce reduction, impairment losses, and other special items—pre-tax and after-tax amounts for 2002, 2001, and 2000.
	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.

Here's Where You Look in Part II		Here's What You'll Find
Item	**Section**	
Notes to Consolidated *Financial* Statements	Note 4. Investments	➜ Real estate, power project, and financial investments for the last two years.
	Note 5. Regulatory Assets	➜ Regulatory assets for the last two years.
	Note 6. 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. ➜ Information on other postemployment benefits. ➜ Employee savings plan information and company-matching contributions.
	Note 7. 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.
	Note 8. Long-Term Debt and Preference Stock	➜ Long-term debt and preference stock details for Constellation Energy, Baltimore Gas and Electric, and our nonregulated businesses.
	Note 9. Taxes	➜ Income tax details for the last three years.
	Note 10. Leases	➜ Lease payment details for the last three years, for the next five years, and for beyond 2007.
	Note 11. Commitments, Guarantees, and Contingencies	➜ Commitments for the next five years and beyond 2007. ➜ Financial guarantees we've made for our businesses. ➜ Environmental issues and legal proceedings involving our company. ➜ Nuclear fuel storage issues and insurance coverage. ➜ Issues concerning our California power purchase agreements.
	Note 12. Hedging Activities and Fair Value of Financial Instruments	➜ Actions to manage interest rate exposure and electricity price fluctuations, and results of those actions over the last two years. ➜ Information on the fair value of our financial instruments.
	Note 13. Stock-Based Compensation	➜ Stock option and stock awards for the last three years.
	Note 14. Acquisitions	➜ Description of and financial information on Alliance/Fellon-McCord, NewEnergy, and Nine Mile Point acquisitions.
	Note 15. Related Party Transactions — BGE	➜ Relationships and interactions among our subsidiaries — their effect on our income statement and balance sheet.
	Note 16. Quarterly Financial Data	➜ Quarterly revenue, income, and earnings for Constellation Energy and Baltimore Gas and Electric over the last two years.

10-K Glossary

Aggregator: a company or agent that combines the energy needs of multiple customers, and then buys or provides the energy and services needed.

Dekatherm: the term used in measuring amounts of natural gas; one dekatherm equals 10 therms or one million BTU; a BTU is the quantity of heat necessary to raise the temperature of a pound of water by one degree Fahrenheit.

Deregulation: the elimination of regulation from a previously regulated process, function, or industry.

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 to establish and improve standards of financial accounting and reporting.

Full Requirements Service: a product offering that handles all of a customer's fluctuating 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.

Independent Power Project: a generating plant that produces power primarily for wholesale customers and that operates independently of a traditional utility.

Independent System Operator: a federally regulated organization that manages regional transmission lines that 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.

Megawatthour: 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 power marketing and other services to provide energy solutions to meet the needs of customers throughout North America.

Nonregulated Business: the portion of our business whose operations and prices are driven primarily by the needs of the marketplace.

Nuclear Decommissioning Trust Fund: a federally mandated fund set up to ensure that nuclear power plant owners put aside enough money to pay for the cleaning up and dismantling of 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.

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 that 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: the obligation of a utility, such as Baltimore Gas and Electric, to supply electricity for those customers who have not chosen an alternate supplier.

Transmission: the sending of electricity at a higher 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 entities such as utilities, distribution companies, electric co-operatives, municipalities, and power marketers who sell or distribute the energy to others.

Shareholder Information

Common Stock Dividends and Price Ranges

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		

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

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

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 to our Shareholder Services group, the company will furnish, without charge, additional copies of its Form 10-K.

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 Agents and Registrars
Transfer Agent and Registrar:
Constellation Energy Group, Inc.
Baltimore, Maryland

Co-Transfer Agent and Registrar:
Continental Stock Transfer and Trust Company
8th Floor
17 Battery Place South
New York, NY 10004

Shareholder Assistance and Inquiries
If you need assistance with lost or stolen stock certificates or dividend checks, name changes, address changes, stock transfers, the Shareholder Investment Plan, or other matters, you may visit our Web site at constellation.com or contact our Shareholder Services representatives as follows:

By telephone (Monday – Friday, 8 a.m. – 4:45 p.m. EST):

Baltimore Metropolitan Area	410-783-5920
Within Maryland	1-800-492-2861
Outside Maryland	1-800-258-0499

By U.S. mail:
Constellation Energy Group, Inc.
Shareholder Services
P.O. Box 1642
Baltimore, MD 21203-1642

In person or by overnight delivery:
Constellation Energy Group, Inc.
Shareholder Services, Room 800
39 W. Lexington Street
Baltimore, MD 21201

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

FORM 10-K

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

For the fiscal year ended **DECEMBER 31, 2002**

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

MARYLAND

(States of incorporation)

750 E. PRATT STREET BALTIMORE, MARYLAND 21202

(Address of principal executive offices) (Zip Code)

410-234-5000

(Registrants' telephone number, including area code)

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

Title of each class	Name of Each Exchange on Which Registered
Constellation Energy Group, Inc. Common Stock—Without Par Value	New York Stock Exchange, Inc. Chicago Stock Exchange, Inc. Pacific Exchange, Inc.
7.16% Trust Originated Preferred Securities ($25 liquidation amount per preferred security) issued by BGE Capital Trust I, fully and unconditionally guaranteed, based on several obligations, by Baltimore Gas and Electric Company	New York Stock Exchange, Inc.

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

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months, and (2) have been subject to such filing requirements for the past 90 days. Yes ☒ 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 28, 2002 was approximately $4,791,476,554 and February 28, 2003 was approximately $4,293,890,795 based upon New York Stock Exchange composite transaction closing price.

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

DOCUMENTS INCORPORATED BY REFERENCE

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

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

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Forward Looking Statements

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

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

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

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

PART I

Item 1. Business

Overview

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

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

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

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

Our merchant energy business includes:

- fossil, nuclear, and hydroelectric generating facilities and interests in qualifying facilities and power projects in the United States,
- origination of structured transactions (such as load-serving, tolling contracts, and power purchase agreements), and risk management services (hedging of output from generating facilities and fuel costs),
- electric and gas retail energy services to large commercial and industrial customers, and
- generation and consulting services.

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

Our other nonregulated businesses:

- design, construct, and operate single-site heating, cooling, and cogeneration facilities for commercial and industrial customers,
- provide home improvements, service heating, air conditioning, plumbing, electrical, and indoor air quality systems, and provide electric and natural gas retail marketing, and
- own and operate a district cooling system for commercial customers in the City of Baltimore, Maryland.

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

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

Operating Segments

The percentages of revenues, net income, and assets attributable to our operating segments are shown in the tables below. We present information about our operating segments, including certain special items, in *Note 3 to Consolidated Financial Statements.* Effective July 1, 2000, the financial results of the electric generation portion of our business are included in the merchant energy business segment. Prior to that date, the financial results are included in the regulated electric segment.

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

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

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

(1) Excludes special items included in operations and a cumulative effect of change in accounting principle as discussed in more detail in *Item 8. Financial Statements and Supplementary Data.*

Merchant Energy Business

Introduction

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

Our merchant energy business:

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

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

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

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

PJM Platform

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

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

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

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

Plants with Power Purchase Agreements

We own 2,530 MW of nuclear and natural gas generation capacity, and have under construction an 830 MW natural gas-fired facility that will commence operation in 2003, with power purchase agreements for their output. These facilities include Nine Mile Point, which is our second largest generating station. We purchased 100% of Unit 1 (609 MW) and 82% of Unit 2 (941 MW) in November 2001. The remaining interest in Nine Mile Point Unit 2 is owned by a subsidiary of the Long Island Power Authority. Unit 1 entered service in 1969 and Unit 2 in 1988. Nine Mile Point is located within the New York Independent System Operator (NYISO) region.

We sell 90 percent of our share of the Nine Mile Point plant's output back to the sellers at an average price of nearly $35 per megawatt-hour (MWH) under agreements that terminate between 2009 and 2010. The agreements for the output of both units are unit contingent (if the output is not available because the plant is not operating, there is no requirement to provide output from other sources). The remaining 10% of Nine Mile Point's output is managed by our origination and risk management operation and sold into the wholesale market.

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

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

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

Our other facilities with power purchase agreements consist of:

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

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

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

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

Competitive Supply

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

Origination of Structured Transactions

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

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

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

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

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

Risk Management Activities

Our origination and risk management operation actively uses energy and energy-related commodities in order to manage our portfolio of energy purchases and sales to customers through structured transactions, to obtain market intelligence, and to take advantage of arbitrage opportunities that exist across different markets. These activities involve the use of a variety of instruments, including:

- forward contracts (which commit us to purchase or sell energy commodities in the future),

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

Active portfolio management allows our origination and risk management operation to manage and hedge its fixed-price purchase and sale commitments; provide fixed-price commitments to customers and suppliers; reduce exposure to the volatility of cash market prices; and hedge fuel requirements at our generation facilities.

Other

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

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

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

We also provide the following services:

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

Fuel Sources

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

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

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

(2) Switches between natural gas and oil.

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

Nuclear

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

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

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

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

*represents our proportionate ownership interest

The supply of fuel for nuclear generating stations includes the:

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

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

The nuclear fuel markets are competitive and we do not anticipate any problem in meeting our future requirements.

Storage of Spent Nuclear Fuel—Federal Facilities

One of the issues associated with the operation and decommissioning of nuclear generating facilities is disposal of spent nuclear fuel. The Nuclear Waste Policy Act of 1982 required the federal government, through the Department of Energy (DOE) by January 31, 1998, to begin to dispose of spent nuclear fuel. The federal government has stated that it will not meet that obligation until 2010 at the earliest.

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

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

Storage of Spent Nuclear Fuel—On-Site Facilities

Calvert Cliffs has a license from the NRC to operate an on-site independent spent fuel storage installation that expires in 2012. We have storage capacity at Calvert Cliffs that will accommodate spent fuel from operations through 2008. In addition, we can expand our temporary storage capacity at Calvert Cliffs to meet future requirements until approximately 2025. Currently, Nine Mile Point does not have independent spent fuel storage capacity. Rather, Nine Mile Point's Unit 1 has sufficient storage capacity within the plant until the end of its current operating license in 2009. If license renewal is obtained, independent spent fuel storage capability will need to be developed. Nine Mile Point's Unit 2 has sufficient storage capacity within the plant until 2012. After that time independent spent fuel storage capability may need to be developed.

Cost for Decommissioning Uranium Enrichment Facilities

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

Cost for Decommissioning

We are obligated to decommission our nuclear plants at the time these plants cease operation. Both Calvert Cliffs and Nine Mile Point are required by the NRC to prepare financially for this decommissioning. When BGE transferred all of its nuclear generating assets to our merchant energy business, it also transferred the trust fund established to pay for decommissioning Calvert Cliffs. At December 31, 2002, the trust fund was $239.7 million.

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

The sellers of Nine Mile Point transferred a \$441.7 million decommissioning trust fund at the time of sale. In return, Nine Mile Point assumed all liability for the costs to decommission Unit 1 and 82% of the cost to decommission Unit 2. We believe that this amount is adequate to cover our responsibility for decommissioning Nine Mile Point to a greenfield status (restoration of the site so that it substantially matches the natural state of the surrounding properties and the site's intended use). At December 31, 2002, the Nine Mile Point trust fund was \$405.7 million.

Coal

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

	Approximate Annual Coal Requirement (tons)	Special Coal Restrictions
Brandon Shores Units 1 and 2 (combined)	3,500,000	Sulfur content less than 0.8%
C. P. Crane Units 1 and 2 (combined)	850,000	Low ash melting temperature
H. A. Wagner Units 2 and 3 (combined)	1,100,000	Sulfur content no more than 1%

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

All of the Conemaugh and Keystone plants' annual coal requirements are purchased from regional suppliers on the open market. The sulfur restrictions on coal are approximately 2.5% for the Keystone plant and approximately 4.5% for the Conemaugh plant.

The annual coal requirements for the ACE, Jasmin, and POSO plants, which are located in California, are supplied under contracts with mining operators. Each plant is restricted to coal with sulfur content less than 4%.

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

Gas

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

Oil

Under normal burn practices, our requirements for residual fuel oil (No. 6) amount to approximately 1,500,000 to 2,000,000 barrels of low-sulfur oil per year. Deliveries of residual fuel oil are made from the suppliers' Baltimore Harbor marine terminal for distribution to the various generating plant locations. Also, based on normal burn practices, we also require approximately 5,000,000 to 6,000,000 gallons of distillates (No. 2 oil and kerosene) annually, but these requirements can vary substantially from year to year depending upon the relationship between energy prices and fuel costs, weather conditions, and operating requirements. Distillates are purchased from the suppliers' Baltimore truck terminals for distribution to the various generating plant locations. We have contracts with various suppliers to purchase oil at spot prices, and for future delivery, to meet our requirements.

Competition

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

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

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

During the transition of the energy industry to competitive markets, it is difficult for us to assess our position versus the position of existing power providers and new entrants because each company may employ widely differing strategies in their fuel supply and power sales contracts with regard to pricing, terms and conditions. Further difficulties in making competitive assessments of our company arise from states considering different types of regulatory initiatives concerning competition in the power industry. Increased competition that resulted from some of these initiatives in several states contributed in some instances to a reduction in electricity prices and put pressure on electric utilities to lower their costs, including the cost of purchased electricity. In addition, some states that were considering deregulation have slowed their plans or postponed consideration of deregulation.

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

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

Merchant Energy Operating Statistics

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

Operating statistics do not reflect the elimination of intercompany transactions.

Baltimore Gas and Electric Company

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

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

BGE's electric and gas revenues come from many customers—residential, commercial, and industrial. In 2002, BGE's largest electric customer provided approximately three percent of BGE's total electric revenues. In 2002, BGE's largest gas customer provided approximately one percent of BGE's total gas revenues.

Electric Business

Electric Regulatory Matters and Competition

Deregulation

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

- All customers can choose their electric energy supplier. BGE provides a fixed price standard offer service over various time periods for different classes of customers that do not select an alternative supplier until June 30, 2006.
- While BGE does not sell electric commodity to all customers in its service territory, BGE does deliver electricity to all customers and provides meter reading, billing, emergency response, regular maintenance, and balancing services.
- BGE provides a market rate standard offer service for those commercial and industrial customers who are no longer eligible for fixed price standard offer service until June 30, 2006.
- BGE reduced residential base rates by approximately 6.5% on average, or about $54 million a year, from rates prior to July 1, 2000. These rates will not change before July 2006. While total residential base rates remain unchanged over this transition period (July 1, 2000 through June 30, 2006), the increase in the standard offer service rate is offset by a corresponding decrease in the competitive transition charge (CTC) that BGE receives from its customers.
- Commercial and industrial customers have several service options that will fix electric energy rates through June 30, 2004 and transition charges through June 30, 2006.
- BGE transferred, at book value, its nuclear generating assets, its nuclear decommissioning trust fund, and related liabilities to Calvert Cliffs Nuclear Power Plant, Inc. In addition, BGE transferred, at book value, its fossil generating assets and related liabilities and its partial ownership interest in two coal plants and a hydroelectric plant located in Pennsylvania to Constellation Power Source Generation.
- BGE assigned approximately $47 million to Calvert Cliffs Nuclear Power Plant, Inc. and $231 million to Constellation Power Source Generation of tax-exempt debt related to the transferred assets. At December 31, 2002, BGE remains contingently liable for the $269.8 million outstanding balance of this debt.

Standard Offer Service

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

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

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

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

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

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

Competition

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

Electric Load Management

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

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

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

Transmission and Distribution Facilities

BGE maintains approximately 250 substations and 1,300 circuit miles of transmission lines throughout central Maryland. BGE also maintains nearly 22,500 circuit miles of distribution lines. The transmission facilities are connected to those of neighboring utility systems as part of the PJM Interconnection. Under the PJM Tariff and various agreements, BGE and other market participants can use regional transmission facilities for energy, capacity and ancillary services transactions including emergency assistance.

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

Electric Operating Statistics

	2002	2001	2000(A)	1999(A)	1998(A)
Revenues *(In millions)*					
Residential	$ 946.6	$ 885.3	$ 922.6	$ 975.2	$ 948.6
Commercial	809.5	903.0	926.2	939.3	912.9
Industrial	169.6	218.1	203.6	204.3	211.5
System Sales	1,925.7	2,006.4	2,052.4	2,118.8	2,073.0
Interchange Sales	—	—	53.8	112.1	120.8
Other (B)	40.3	33.6	29.0	29.1	27.0
Total	$1,966.0	$2,040.0	$2,135.2	$2,260.0	$2,220.8
Sales *(In thousands)*—MWH					
Residential	12,652	11,714	11,675	11,349	10,965
Commercial	14,602	14,147	14,042	13,565	13,219
Industrial	4,475	4,445	4,476	4,350	4,583
System Sales	31,729	30,306	30,193	29,264	28,767
Customers *(In thousands)*					
Residential	1,052.3	1,040.5	1,033.4	1,021.4	1,009.1
Commercial	110.8	110.9	108.9	107.7	106.5
Industrial	4.9	5.0	5.0	4.7	4.6
Total	1,168.0	1,156.4	1,147.3	1,133.8	1,120.2

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

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

Operating statistics do not reflect the elimination of intercompany transactions.

Gas Business

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

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

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

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

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

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

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

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

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

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

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

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

Gas Operating Statistics

	2002	2001	2000	1999	1998
Revenues *(In millions)*					
Residential					
Excluding Delivery Service	$ 342.1	$ 378.4	$ 328.4	$ 298.1	$ 279.2
Delivery Service	16.5	16.3	23.5	11.5	4.9
Commercial					
Excluding Delivery Service	89.4	115.5	97.9	79.3	75.6
Delivery Service	29.2	21.4	25.8	24.4	19.4
Industrial					
Excluding Delivery Service	9.3	12.8	10.9	8.2	8.0
Delivery Service	13.9	13.8	16.3	16.1	16.0
System Sales	500.4	558.2	502.8	437.6	403.1
Off-system Sales	74.8	113.6	101.0	42.9	40.9
Other	6.1	8.9	7.8	7.6	7.1
Total	$ 581.3	$ 680.7	$ 611.6	$ 488.1	$ 451.1
Sales *(In thousands)*—DTH					
Residential					
Excluding Delivery Service	35,364	33,147	34,561	34,272	33,595
Delivery Service	6,404	7,201	9,209	4,468	1,890
Commercial					
Excluding Delivery Service	11,583	12,334	13,186	11,733	11,775
Delivery Service	28,429	25,037	22,921	20,288	16,633
Industrial					
Excluding Delivery Service	1,207	1,386	1,386	1,367	1,412
Delivery Service	23,689	23,872	32,382	33,118	34,798
System Sales	106,676	102,977	113,645	105,246	100,103
Off-system Sales	18,551	20,012	22,456	15,543	16,724
Total	125,227	122,989	136,101	120,789	116,827
Customers *(In thousands)*					
Residential	567.3	558.7	553.7	543.5	532.5
Commercial	40.7	40.2	40.1	39.9	39.6
Industrial	1.3	1.4	1.4	1.3	1.3
Total	609.3	600.3	595.2	584.7	573.4

Operating statistics do not reflect the elimination of intercompany transactions.

Franchises

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

Other Nonregulated Businesses

Energy Products and Services

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

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

Home Products and Electric and Gas Retail Marketing

We offer services to customers including:

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

District Cooling Services

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

Other

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

Consolidated Capital Requirements

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

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

Environmental Matters

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

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

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

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

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

Clean Air Act

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

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

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

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

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

In general, such standards can require the installation of additional air pollution control equipment upon the major modification of an existing plant. Although there have not been any new source review-related suits filed against our facilities, there can be no assurance that any of them will not be the target of an action in the future. Based on the levels of emissions control that the EPA and states are seeking in these new source review enforcement actions, we believe that material additional costs and penalties could be incurred, and planned capital expenditures could be accelerated, if the EPA was successful in any future actions regarding our facilities.

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

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

Clean Water Act

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

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

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

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

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

Metal Bank

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

Kane and Lombard Streets

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

68th Street Dump

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

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

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

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

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

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

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

Item 2. Properties
Constellation Energy's corporate offices occupy approximately 85,000 square feet of leased office space in Baltimore, Maryland. The corporate offices for most of our merchant energy business occupy approximately 100,000 square feet of leased office space in another building in Baltimore, Maryland. We describe our electric generation properties on the next page. We also have leases for other offices and services located in the Baltimore metropolitan region, and for various real property and facilities relating to our generation projects.

We own BGE's principal headquarters building in downtown Baltimore. BGE owns propane air and liquefied natural gas facilities as discussed in *Item 1. Business—Gas Business* section.

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

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

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

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

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

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

The following table describes our generating facilities:

Plant	Location	Installed Capacity (MW)	% Owned	Capacity Owned (MW)	Primary Fuel
		(at December 31, 2002)		(at December 31, 2002)	
PJM Platform					
Calvert Cliffs	Calvert Co., MD	1,685	100.0	1,685	Nuclear
Brandon Shores	Anne Arundel Co., MD	1,286	100.0	1,286	Coal
H. A. Wagner	Anne Arundel Co., MD	1,020	100.0	1,020	Coal/Oil/Gas
C. P. Crane	Baltimore Co., MD	399	100.0	399	Oil/Coal
Keystone	Armstrong and Indiana Cos., PA	1,711	21.0	359 (A)	Coal
Conemaugh	Indiana Co., PA	1,711	10.6	181 (A)	Coal
Perryman	Harford Co., MD	360	100.0	360	Oil/Gas
Riverside	Baltimore Co., MD	251	100.0	251	Oil/Gas
Handsome Lake	Rockland Twp, PA	250	100.0	250	Gas
Notch Cliff	Baltimore Co., MD	128	100.0	128	Gas
Westport	Baltimore City, MD	121	100.0	121	Gas
Gould Street	Baltimore City, MD	104	100.0	104	Oil/Gas
Philadelphia Road	Baltimore City, MD	64	100.0	64	Oil
Safe Harbor	Safe Harbor, PA	416	66.7	277	Hydro
Total PJM Platform		9,506		6,485	
Plants with Power Purchase Agreements					
Nine Mile Point Unit 1	Scriba, NY	609	100.0	609	Nuclear
Nine Mile Point Unit 2	Scriba, NY	1,148	82.0	941	Nuclear
Oleander	Brevard Co., FL	680	100.0	680	Oil/Gas
University Park	Chicago, IL	300	100.0	300	Gas
Total Plants with Power Purchase Agreements		2,737		2,530	
Competitive Supply					
Rio Nogales	Seguin, TX	800	100.0	800	Gas
Other					
Holland Energy	Shelby Co., IL	665	100.0	665	Gas
Big Sandy	Neal, WV	300	100.0	300	Gas
Wolf Hills	Bristol, VA	250	100.0	250	Gas
Panther Creek	Nesquehoning, PA	83	50.0	42	Waste Coal
Colver	Colver Township, PA	110	25.0	28	Waste Coal
Sunnyside	Sunnyside, UT	53	50.0	26	Waste Coal
ACE	Trona, CA	102	30.3	31	Coal
Jasmin	Kern Co., CA	33	50.0	17	Coal
POSO	Kern Co., CA	33	50.0	17	Coal
Puna I	Hilo, HI	30	50.0	15	Geothermal
Mammoth Lakes G-1	Mammoth Lakes, CA	8	50.0	4	Geothermal
Mammoth Lakes G-2	Mammoth Lakes, CA	12	50.0	6	Geothermal
Mammoth Lakes G-3	Mammoth Lakes, CA	12	50.0	6	Geothermal
Soda Lake I	Fallon, NV	3	50.0	2	Geothermal
Soda Lake II	Fallon, NV	13	50.0	7	Geothermal
Stillwater	Fallon, NV	13	50.0	6	Geothermal
Rocklin	Placer Co., CA	24	50.0	12	Biomass
Fresno	Fresno, CA	24	50.0	12	Biomass
Chinese Station	Sonora, CA	22	45.0	10	Biomass
Malacha	Muck Valley, CA	32	50.0	16	Hydro
Central Wayne	Dearborn, MI	22	50.0	11	Municipal Solid Waste
SEGS IV	Kramer Junction, CA	30	12.0	4	Solar
SEGS V	Kramer Junction, CA	30	4.0	1	Solar
SEGS VI	Kramer Junction, CA	30	9.0	3	Solar
Total Other		1,934		1,491	
Total Generating Facilities		14,977		11,306	

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

The following table describes our processing facilities:

Plant	Location	Installed Capacity (MW) (at December 31, 2002)	% Owned	Capacity Owned (MW) (at December 31, 2002)	Primary Fuel
A/C Fuels	Hazelton, PA	—	50.0	—	Coal Processing
Gary PCI	Gary, IN	—	24.5	—	Coal Processing
PC Synfuel VA I	Appalachia, VA	—	16.7	—	Synfuel Processing
PC Synfuel WV I	Charleston, WV	—	16.7	—	Synfuel Processing
PC Synfuel WV II	Wheelersburg, OH	—	16.7	—	Synfuel Processing
PC Synfuel WV III	Mayberry, WV	—	16.7	—	Synfuel Processing

Item 3. Legal Proceedings

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

Item 4. Submission of Matters to Vote of Security Holders

Not applicable.

Executive Officers of the Registrant

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

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

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

PART II

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

Stock Trading

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

As of February 28, 2003, there were 50,914 common shareholders of record.

Dividend Policy

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

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

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

Quarterly dividends were declared on our common stock during 2002 and 2001 in the amounts set forth below.

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

- BGE elects to defer interest payments on the 7.16% Deferrable Interest Subordinated Debentures due June 30, 2038, and any deferred interest remains unpaid; or
- all dividends (and any redemption payments) due on BGE's preference stock have not been paid.

Common Stock Dividends and Price Ranges

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

* Based on New York Stock Exchange Composite Transactions.

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

	2002	2001	2000	1999	1998
	(Dollar amounts in millions, except per share amounts)				
Summary of Operations					
Total Revenues	$ 4,703.0	$ 3,878.8	$ 3,774.4	$3,830.9	$3,382.5
Total Expenses	3,878.1	3,527.2	3,009.9	3,081.0	2,647.9
Net Gain on Sales of Investments and Other Assets	261.3	6.2	78.1	10.0	3.9
Income From Operations	1,086.2	357.8	842.6	759.9	738.5
Other Income	30.5	1.3	4.2	7.9	5.7
Fixed Charges	281.5	238.8	271.4	255.0	260.6
Income Before Income Taxes	835.2	120.3	575.4	512.8	483.6
Income Taxes	309.6	37.9	230.1	186.4	177.7
Income Before Extraordinary Item and Cumulative Effect of Change in Accounting Principle	525.6	82.4	345.3	326.4	305.9
Extraordinary Loss, Net of Income Taxes	—	—	—	(66.3)	—
Cumulative Effect of Change in Accounting Principle, Net of Income Taxes	—	8.5	—	—	—
Net Income	$ 525.6	$ 90.9	$ 345.3	$ 260.1	$ 305.9
Earnings Per Common Share and Earnings Per Common Share—Assuming Dilution Before Extraordinary Item and Cumulative Effect of Change in Accounting Principle	$ 3.20	$ .52	$ 2.30	$ 2.18	$ 2.06
Extraordinary Loss	—	—	—	(.44)	—
Cumulative Effect of Change in Accounting Principle	—	.05	—	—	—
Earnings Per Common Share and Earnings Per Common Share—Assuming Dilution	$ 3.20	$ .57	$ 2.30	$ 1.74	$ 2.06
Dividends Declared Per Common Share	$ .96	$ .48	$ 1.68	$ 1.68	$ 1.67
Summary of Financial Condition					
Total Assets	$ 14,128.9	$14,109.4	$12,939.3	$9,745.1	$9,434.1
Short-Term Borrowings	$ 10.5	$ 975.0	$ 243.6	$ 371.5	$ —
Current Portion of Long-Term Debt	$ 426.2	$ 1,406.7	$ 906.6	$ 808.3	$ 541.7
Capitalization					
Long-Term Debt	$ 4,613.9	$ 2,712.5	$ 3,159.3	$2,575.4	$3,128.1
Minority Interests	105.3	101.7	97.7	95.2	2.0
Preference Stock Not Subject to Mandatory Redemption	190.0	190.0	190.0	190.0	190.0
Common Shareholders' Equity	3,862.3	3,843.6	3,174.0	3,017.5	2,995.9
Total Capitalization	$ 8,771.5	$ 6,847.8	$ 6,621.0	$5,878.1	$6,316.0
Financial Statistics at Year End					
Ratio of Earnings to Fixed Charges	3.33	1.18	2.78	2.87	2.60
Book Value Per Share of Common Stock	$ 23.44	$ 23.48	$ 21.09	$ 20.17	$ 20.08

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

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

Baltimore Gas and Electric Company and Subsidiaries

	2002	2001	2000(A)	1999	1998
			(Dollar amounts in millions)		
Summary of Operations					
Total Revenues	**$ 2,547.3**	$2,720.7	$2,746.8	$3,092.2	$3,386.4
Total Expenses	**2,181.0**	2,408.9	2,334.4	2,387.9	2,647.9
Income From Operations	**366.3**	311.8	412.4	704.3	738.5
Other Income	**10.7**	0.4	7.5	8.4	5.7
Fixed Charges	**140.6**	154.6	184.0	205.9	238.8
Income Before Income Taxes	**236.4**	157.6	235.9	506.8	505.4
Income Taxes	**93.3**	60.3	92.4	178.4	177.7
Income Before Extraordinary Item	**143.1**	97.3	143.5	328.4	327.7
Extraordinary Loss, Net of Income Taxes	**—**	—	—	(66.3)	—
Net Income	**143.1**	97.3	143.5	262.1	327.7
Preference Stock Dividends	**13.2**	13.2	13.2	13.5	21.8
Earnings Applicable to Common Stock	**$ 129.9**	$ 84.1	$ 130.3	$ 248.6	$ 305.9
Summary of Financial Condition					
Total Assets	**$ 4,779.9**	$4,954.5	$4,654.2	$7,272.6	$9,434.1
Short-Term Borrowings	**$ —**	$ —	$ 32.1	$ 129.0	$ —
Current Portion of Long-Term Debt	**$ 420.7**	$ 666.3	$ 567.6	$ 523.9	$ 541.7
Capitalization					
Long-Term Debt	**$ 1,499.1**	$1,821.7	$1,864.4	$2,206.0	$3,128.1
Minority Interest	**19.4**	5.0	4.6	4.2	1.1
Preference Stock Not Subject to Mandatory Redemption	**190.0**	190.0	190.0	190.0	190.0
Common Shareholder's Equity	**1,461.7**	1,131.4	802.3	2,355.4	2,981.5
Total Capitalization	**$ 3,170.2**	$3,148.1	$2,861.3	$4,755.6	$6,300.7
Financial Statistics at Year End					
Ratio of Earnings to Fixed Charges	**2.66**	1.99	2.27	3.45	2.94
Ratio of Earnings to Fixed Charges and Preferred and Preference Stock Dividends	**2.31**	1.75	2.03	3.14	2.60

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

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

Introduction

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

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

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

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

Our other nonregulated businesses:

- design, construct, and operate single-site heating, cooling, and cogeneration facilities for commercial and industrial customers,
- provide home improvements, service heating, air conditioning, plumbing, electrical, and indoor air quality systems, and provide electric and natural gas retail marketing, and
- own and operate a district cooling system for commercial customers in the City of Baltimore, Maryland.

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

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

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

As you read this discussion and analysis, refer to our Consolidated Statements of Income, which present the results of our operations for 2002, 2001, and 2000. We analyze and explain the differences between periods in the specific line items of the Consolidated Statements of Income.

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

Critical Accounting Policies

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

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

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

Management believes the following accounting policies represent critical accounting policies as defined by the SEC. The SEC defines critical accounting policies as those that are both most important to the portrayal of a company's financial condition and results and require management's most difficult, subjective, or complex judgment, often as a result of the need to make estimates about the effect of matters that are inherently uncertain and may change in subsequent periods. We discuss our significant accounting policies, including those that do not require management to make difficult, subjective, or complex judgments or estimates, in *Note 1*.

Revenue Recognition/Mark-to-Market Method of Accounting

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

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

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

At December 31, 2002, mark-to-market energy assets and liabilities consisted of a combination of energy and energy-related derivative and non-derivative contracts. While some of these contracts represent commodities or instruments for which prices are available from external sources, other commodities and certain contracts are not actively traded and are valued using modeling techniques to determine expected future market prices, contract quantities, or both. The market prices and quantities used to determine fair value reflect management's best estimate considering various factors. However, future market prices and actual quantities will vary from those used in recording mark-to-market energy assets and liabilities, and it is possible that such variations could be material.

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

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

- Close-out reserve—this reserve represents the estimated cost to close out or sell to a third-party open mark-to-market positions. This reserve has the effect of valuing "long" positions at the bid price and "short" positions at the offer price. We compute this reserve based on our estimate of the bid/offer spread for each commodity and option price and the absolute quantity of our open positions for each year. Effective July 1, 2002, to the extent that we are not able to obtain market information for similar contracts, the close-out reserve is equivalent to the initial contract margin, thereby resulting in no gain or loss at inception. The level of total close-out reserves increases as we have larger unhedged positions, bid-offer spreads increase, or market information is not available, and it decreases as we reduce our unhedged positions, bid-offer spreads decrease, or market information becomes available.
- Credit-spread adjustment—for risk management purposes, we compute the value of our mark-to-market assets and liabilities using a risk-free discount rate. In order to compute fair value for financial reporting purposes, we adjust the value of our mark-to-market assets to reflect the credit-worthiness of each individual counterparty based upon published credit ratings, where available, or equivalent internal credit ratings and associated default probability percentages. We compute this reserve by applying the appropriate default probability percentage to our outstanding credit exposure, net of collateral, for each counterparty. The level of this reserve increases as our credit exposure to counterparties increases, the maturity terms of our transactions increase, or the credit ratings of our counterparties deteriorate, and it decreases when our credit exposure to counterparties decreases, the maturity terms of our transactions decrease, or the credit ratings of our counterparties improve.

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

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

- EITF 02-3 prohibits the use of mark-to-market accounting for any energy-related contracts that are not derivatives. Any contracts subject to EITF 02-3 must be accounted for on the accrual basis and recorded in the income statement gross rather than net upon application of EITF 02-3. This change applied immediately to new contracts executed after October 25, 2002 and applied to existing non-derivative energy-related contracts beginning January 1, 2003.
- We are required to report the impact of initially applying EITF 02-3 as the cumulative effect of a change in accounting principle.
- The EITF minutes on Issue 02-3 indicate that an entity should not record unrealized gains or losses at the inception of derivative contracts unless the fair value of the contracts is evidenced by observable market data.

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

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

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

	Assets	Liabilities	Net
	(In millions)		
Mark-to-market energy contracts			
Current	$ 144.0	$ 94.1	$ 49.9
Noncurrent	1,348.2	881.5	466.7
Total	1,492.2	975.6	516.6
Other			
Current	85.7	56.8	28.9
Noncurrent	24.2	2.5	21.7
Total	109.9	59.3	50.6
Balance at December 31, 2002	1,602.1	1,034.9	567.2
Impact of EITF 02-3 Adoption			
Non-derivative net asset reversed as cumulative effect of a change in accounting principle			
Mark-to-market energy contracts	(494.7)	(119.8)	(374.9)
Other	(109.9)	(59.3)	(50.6)
Total non-derivative net asset reversed as cumulative effect of a change in accounting principle	(604.6)	(179.1)	(425.5)
Derivatives designated as hedges	(88.3)	(94.4)	6.1
Derivatives designated as normal purchases and sales	(192.6)	(128.3)	(64.3)
Mark-to-market derivatives remaining after adoption of EITF 02-3 on January 1, 2003	$ 716.6	$ 633.1	$ 83.5

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

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

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

However, the impact of applying EITF 02-3 in the future will be affected by many factors, including:

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

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

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

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

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

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

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

For long-lived assets that are expected to be held and used, SFAS No. 144 requires that an impairment loss shall only be recognized if the carrying amount of an asset is not recoverable and exceeds its fair value. The carrying amount of an asset is not recoverable under SFAS No. 144 if the carrying amount exceeds the sum of the undiscounted future cash flows expected to result from the use and eventual disposition of the asset. Therefore, when we believe an impairment condition may have occurred, we are required to estimate the undiscounted future cash flows associated with a long-lived asset or group of long-lived assets. This necessarily involves judgement surrounding the inherent uncertainty of future cash flows.

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

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

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

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

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

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

Significant Events

2002

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

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

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

Workforce Reduction Costs

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

Costs Associated with 2001 Programs

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

- We recorded $52.9 million when 308 employees elected the age 50 to 54 Voluntary Special Early Retirement Program (VSERP).
- We reversed $17.8 million of the $25.1 million involuntary severance accrual that was recorded in 2001 to reflect the employees that elected the age 50 to 54 VSERP and whose costs were included in that program. Ultimately, we involuntarily severed 129 employees that resulted in a total cost for the involuntary severance program of $7.3 million.
- We recorded $29.6 million of settlement charges related to our pension plans under SFAS No. 88, *Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits.* These charges reflect the recognition of actuarial gains and losses associated with employees who have retired and taken their pension in the form of a lump-sum payment. Under SFAS No. 88, the settlement charge could not be recognized until lump-sum pension payments exceeded annual pension plan service and interest cost, which occurred in 2002.
- We recorded a $1.6 million expense associated with deferred payments to employees eligible for the VSERP.
- Partially offsetting these costs, we reversed approximately $2.6 million of previously accrued workforce reduction costs primarily as a result of the reversal of education and outplacement assistance benefits we accrued that employees did not utilize to the extent expected.

Costs Associated with 2002 Programs

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

- We recorded $8.5 million for workforce reduction costs for the severance of 120 employees at Calvert Cliffs Nuclear Power Plant (Calvert Cliffs).
- We recorded $1.6 million of workforce reduction costs for the severance of 27 employees in our information technology organization. BGE recorded $0.6 million of this amount.
- We recorded $1.9 million of workforce reduction costs for the severance of 20 employees in our legal organization. BGE recorded $0.9 million of this amount.

Ongoing Impacts

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

Impairment Losses and Other Costs

Investments in Qualifying Facilities and Power Projects

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

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

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

- We recognized a $2.6 million other than temporary decline in value of our investment in a fuel processing site in Pennsylvania where the expected cash flows from a sublease are no longer expected to be sufficient to recover our lease costs associated with this site.
- We recognized a $6.6 million other than temporary decline in value of our investment in a partnership that owns a waste burning power project in Michigan.

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

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

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

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

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

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

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

Closing of BGE Home Retail Merchandise Stores

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

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

Real Estate and International Investments

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

Net Gain on Sales of Investments and Other Assets

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

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

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

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

Acquisitions

NewEnergy

On September 9, 2002, we completed our purchase of AES NewEnergy, Inc. from AES Corporation. Subsequent to the acquisition, we renamed AES NewEnergy, Inc. as Constellation NewEnergy, Inc. (NewEnergy). NewEnergy is a leading national provider of electricity, natural gas, and energy services, serving approximately 4,300 megawatts (MW) of load associated with large commercial and industrial customers in competitive energy markets including the Northeast, Mid-Atlantic, Midwest, Texas and California. We acquired 100% ownership of NewEnergy for cash of $250.3 million including $1.4 million of direct costs associated with the acquisition. We acquired cash of $45.5 million as part of the purchase. We describe the net assets acquired in *Note 14*. We include the results of NewEnergy in our merchant energy business segment beginning on the date of acquisition.

Alliance

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

Renegotiations of our High Desert Power Contract

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

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

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

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

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

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

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

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

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

These differences between actual and expected returns are deferred along with other actuarial gains and losses and reflected in future net periodic pension expense in accordance with SFAS No. 87. Expected and actual returns on pension assets also are affected by plan contributions. In 2002, we contributed $152 million to our pension plans, which included $80 million to the Constellation Energy qualified pension plan and amounts received from the sellers of Nine Mile Point to the Nine Mile Point pension plan. As of the date of this report, we contributed an additional $111 million to our pension plans in 2003.

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

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

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

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

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

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

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

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

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

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

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

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

Net Gain on the Sales of Investments and Other Assets

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

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

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

Nine Mile Point

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

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

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

Bethlehem Steel

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

Strategy

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

The integration of electric generation assets with origination and risk management of energy and energy-related commodities allows our merchant energy business to manage energy price risk over geographic regions and over time. Our focus is on providing solutions to customers' energy needs, and our origination and risk management operation adds value to our generation assets by providing national market access, market infrastructure, real-time market intelligence, risk management and arbitrage opportunities, and transmission and transportation expertise. Generation capacity supports our origination and risk management operation by providing a source of reliable power supply that provides a physical hedge for some of our load-serving activities.

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

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

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

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

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

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

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

Business Environment

General Industry

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

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

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

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

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

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

Electric Competition

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

Maryland

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

- All customers can choose their electric energy supplier. BGE provides fixed price standard offer service over various time periods for different classes of customers that do not select an alternative supplier until June 30, 2006.
- While BGE does not sell electric commodity to all customers in its service territory, BGE does deliver electricity to all customers and provides meter reading, billing, emergency response, regular maintenance, and balancing services.
- BGE provides a market rate standard offer service for those commercial and industrial customers who are no longer eligible for fixed price standard offer service until June 30, 2006.
- BGE reduced residential base rates by approximately 6.5% on average, or about $54 million a year, from rates prior to July 1, 2000. These rates will not change before July 2006. While total residential base rates remain unchanged over this transition period (July 1, 2000 through June 30, 2006), the increase in the standard offer service rate is offset by a corresponding decrease in the competitive transition charge (CTC) that BGE receives from its customers.
- Commercial and industrial customers have several service options that will fix electric energy rates through June 30, 2004 and transition charges through June 30, 2006.

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

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

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

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

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

Other States

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

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

Gas Competition

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

Regulation by the Maryland PSC

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

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

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

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

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

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

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

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

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

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

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

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

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

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

BGE

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

However, the Maryland PSC allows us to record a monthly adjustment to our regulated gas business revenues to eliminate the effect of abnormal weather patterns. We discuss this further in the *Weather Normalization* section.

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

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

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

	2002	2001	30-year Average
Cooling degree-days	1,006	787	836
Percentage change from prior year	27.8%	6.9%	
Heating degree-days	4,542	4,514	4,736
Percentage change from prior year	0.6%	(8.5)%	

Other Factors

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

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

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

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

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

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

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

Environmental and Legal Matters

You will find details of our environmental matters in *Note 11* and *Item 1. Business—Environmental Matters* section. You will find details of our legal matters in *Note 11*. Some of the information is about costs that may be material to our financial results.

Accounting Standards Adopted and Issued

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

Results of Operations

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

Overview

Net Income

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

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

2002

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

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

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

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

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

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

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

2001

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

Net income before special items was $387.2 million, or $2.41 per share, in 2001 compared to $317.3 million, or $2.12 per share, in 2000. Net income before special items was higher compared to 2000 mostly because BGE recorded $75.0 million pre-tax, or approximately $.30 per share, of amortization expense for the reduction of our generating plants associated with the deregulation of electric generation in 2000 that had a negative impact in that year. In addition, we had higher earnings from our regulated gas business in 2001 mostly because of increases in the sharing mechanism under our gas cost adjustment clauses and the increase in our base rates. These increases were offset by the impact of a 6.5% annual electric residential rate reduction that was effective July 1, 2000.

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

- Our merchant energy business recorded in 2000 an expense of $15.0 million after-tax, or $.10 per share, for a deregulation transition cost to Goldman Sachs that had a negative impact in that year.
- BGE recorded an expense of $4.2 million after-tax, or $.03 per share, for its employees that elected to participate in a targeted VSERP in 2000 that had a negative impact in that year.
- We recorded an $8.5 million after-tax, or $.05 per share, gain for the cumulative effect of adopting SFAS No. 133 in the first quarter of 2001.

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

Merchant Energy Business

Background

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

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

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

- We record revenues as they are earned and electric fuel and purchased energy costs as they are incurred for contracts and activities subject to accrual accounting, including certain load-serving activities, as discussed below.
- Prior to the settlement of the forecasted transaction being hedged, we record changes in the fair value of contracts designated as cash-flow hedges in other comprehensive income to the extent that the hedges are effective. We record the effective portion of the changes in fair value of hedges in earnings in the period the settlement of the hedged transaction occurs. We record the ineffective portion of the changes in fair value of hedges, if any, in earnings in the period in which the change occurs.
- We record changes in the fair value of contracts that are subject to mark-to-market accounting in revenues on a net basis in the period in which the change occurs. EITF 02-3 will affect how we apply the mark-to-market method of accounting. We discuss EITF 02-3 in the *Critical Accounting Policies* section and in *Note 1*.

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

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

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

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

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

Our merchant energy business results were as follows:

Net Income

	2002	2001	2000
		(In millions)	
Revenues	$2,765.7	$1,765.5	$1,025.7
Fuel and purchased energy expenses	1,151.3	484.5	199.5
Operations and maintenance expenses	787.4	597.8	387.3
Workforce reduction costs	26.5	46.0	—
Impairment losses and other costs	14.4	46.9	—
Contract termination related costs	—	224.8	—
Depreciation and amortization	242.8	174.9	83.6
Taxes other than income taxes	83.5	49.4	24.6
Net loss on sales of assets	3.7	—	—
Income from Operations	$ 456.1	$ 141.2	$ 330.7
Net Income	$ 247.2	$ 93.1	$ 198.6
Net Income Before Special Items Included in Operations	$ 275.5	$ 291.2	$ 213.6
Workforce reduction costs	(16.0)	(28.0)	—
Impairment of investments in qualifying facilities and domestic power projects	(9.9)	(30.5)	—
Net loss on sales of assets	(2.4)	—	—
Contract termination related costs	—	(139.6)	—
Deregulation transition cost	—	—	(15.0)
Net Income	$ 247.2	$ 93.1	$ 198.6

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

Revenues and Fuel and Purchased Energy Expenses

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

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

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

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

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

PJM Platform

	2002	2001	2000
		(In millions)	
Revenues	$1,391.4	$1,379.2	$731.7
Fuel and purchased energy expenses	527.5	420.9	199.5
Revenues less fuel and purchased energy	$ 863.9	$ 958.3	$532.2

Revenues

BGE Standard Offer Service

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

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

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

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

Other PJM Revenues

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

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

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

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

Fuel and Purchased Energy Expenses

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

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

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

Plants with Power Purchase Agreements

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

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

Competitive Supply

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

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

Accrual Revenues and Fuel and Purchased Energy Expenses

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

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

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

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

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

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

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

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

Mark-to-Market Revenues

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

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

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

Mark-to-market revenues were as follows:

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

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

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

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

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

Mark-to-Market Energy Assets and Liabilities

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

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

At December 31,	2002	2001
	(In millions)	
Current Assets	$ 144.0	$ 398.4
Noncurrent Assets	1,348.2	1,819.8
Total Assets	1,492.2	2,218.2
Current Liabilities	94.1	323.3
Noncurrent Liabilities	881.5	1,476.5
Total Liabilities	975.6	1,799.8
Net mark-to-market energy asset	$ 516.6	$ 418.4

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

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

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

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

	2002		2001	
		(In millions)		
Fair value beginning of year		$418.4		$ 527.9
Changes in fair value recorded as revenues				
Origination transactions	$160.4		$227.0	
Unrealized changes in fair value	66.9		(55.7)	
Changes in valuation techniques	10.8		4.5	
Reclassification of settled contracts to realized	(45.4)		(19.7)	
Total changes in fair value recorded as revenues		192.7		156.1
Changes in fair value recorded as operating expenses		9.0		(15.0)
Changes in value of exchange-listed futures and options		(8.5)		6.9
Net change in premiums on options		(40.1)		(242.2)
Texas contracts re-designated as non-trading		(63.3)		—
Other changes in fair value		8.4		(15.3)
Fair value at end of year		$516.6		$ 418.4

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

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

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

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

- Changes in value of exchange-listed futures and options are adjustments to remove unrealized revenue from exchange-traded contracts that are included in risk management revenues. The fair value of these contracts is recorded in "Accounts receivable" rather than "Mark-to-market energy assets" in our Consolidated Balance Sheets because these amounts are settled through our margin account with a third-party broker.
- Net changes in premiums on options reflects the accounting for premiums on options purchased as an increase in the net mark-to-market energy asset and premiums on options sold as a decrease in the net mark-to-market energy asset.

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

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

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

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

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

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

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

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

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

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

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

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

- observable market prices,
- estimated market prices in the absence of quoted market prices,
- the risk-free market discount rate,
- volatility factors,
- estimated correlation of energy commodity prices,
- estimated volumes for customer requirements, which are influenced by customer switching behavior, impact of temperature on electric prices, and customer acquisition and servicing costs,
- estimated volumes for tolling contracts, and
- expected generation profiles of specific regions.

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

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

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

The fair values in the tables represent expected future cash flows based on the level of forward prices and volatility factors as of December 31, 2002 and could change significantly as a result of future changes in these factors. Additionally, because the depth and liquidity of the power markets varies substantially between regions and time periods, the prices used to determine fair value could be affected significantly by the volume of transactions executed.

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

Other

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

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

Revenues

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

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

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

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

Investments in Qualifying Facilities and Domestic Power Projects
Our merchant energy business holds up to a 50% ownership interest in 28 operating domestic energy projects that consist of electric generation, fuel processing, or fuel handling facilities. Of these 28 projects, 20 are "qualifying facilities" that receive certain exemptions and pricing under the Public Utility Regulatory Policy Act of 1978 based on the facilities' energy source or the use of a cogeneration process. Earnings from our investments were $9.1 million in 2002, $23.1 million in 2001, and $50.2 million in 2000.

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

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

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

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

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

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

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

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

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

These increases were partially offset by the following:

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

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

- Higher operations and maintenance expenses of $203.0 million mostly because 2001 reflects a full year's operation of the generation plants that were transferred from BGE effective July 1, 2000.
- Higher operations and maintenance expenses of $29.5 million associated with the acquisitions of Nine Mile Point in November 2001.
- Higher operations and maintenance expenses of $4.3 million associated with new generating facilities that commenced operations beginning in mid-2001.
- Higher origination and risk management operating expenses of $41.2 million as a result of the growth of the operation and higher direct expenses primarily due to higher transaction volumes.

These increases were partially offset by the following:

- The decrease in the Goldman Sachs fees of $52.4 million due to the termination of the power business services agreement in October 2001. The Goldman Sachs fee was $81.3 million in 2000, which included the $24.0 million, or $.10 per share, deregulation transition cost.
- Lower operations and maintenance expenses at COSI of $20.9 million due to the sale of certain subsidiaries as previously discussed.

Workforce Reduction Costs, Impairment Losses and Other Costs, Contract Termination Related Costs, and Net Loss on Sales of Assets
Our merchant energy business recognized the following in 2002:

- $26.5 million of expenses associated with our workforce reduction efforts,
- $14.4 million of impairment losses for the decline in value of certain investments in partnerships that have investments in qualifying facilities and domestic power projects,

- $6.0 million loss on the sale of a steam turbine generator set, and
- $2.3 million gain on the sale of Cabazon, a wind-powered independent power project located in California.

Our merchant energy business recognized the following in 2001:

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

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

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

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

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

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

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

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

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

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

Net Income

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Electric Fuel and Purchased Energy Expenses

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

Actual Costs

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

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

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

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

Electric Operations and Maintenance Expenses

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

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

Workforce Reduction Costs

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

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

Electric Depreciation and Amortization Expense

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

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

Electric Taxes Other Than Income Taxes

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

Regulated Gas Business

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

Net Income

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

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

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

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

Gas Revenues

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

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

Distribution Sales Volumes

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

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

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

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

Base Rates

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

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

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

Gas Cost Adjustments
We charge our gas customers for the natural gas they purchase from us using gas cost adjustment clauses set by the Maryland PSC as described in *Note 1*. However, under market-based rates, our actual cost of gas is compared to a market index (a measure of the market price of gas in a given period). The difference between our actual cost and the market index is shared equally between shareholders and customers. The shareholders' portion decreased $3.7 million during 2002 compared to 2001. The shareholders' portion increased $3.6 million during 2001 compared to 2000.

Effective November 2001, the Maryland PSC approved an order that modifies certain provisions of the market-based rates incentive mechanism. These provisions require that BGE secure fixed-price contracts for at least 10%, but not more than 20%, of forecasted system supply requirements for the November through March period. These fixed price contracts are not subject to sharing under the market-based rates incentive mechanism. We do not expect these changes to have a material impact on our financial results.

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

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

In December 2002, a Hearing Examiner from the Maryland PSC issued a proposed order related to our annual gas adjustment clause review proceeding that will allow us to recover $1.7 million of a previously established regulatory asset of $9.4 million for certain credits that were over-refunded to customers through our market-based rates. BGE reserved the remaining difference of $7.7 million as disallowed fuel costs. However, we appealed the proposed order. As of the date of this report, the Maryland PSC has not acted on BGE's appeal.

Off-System Sales
Off-system gas sales are low-margin direct sales of gas to wholesale suppliers of natural gas outside our service territory. Off-system gas sales, which occur after we have satisfied our customers' demand, are not subject to gas cost adjustments. The Maryland PSC approved an arrangement for part of the margin from off-system sales to benefit customers (through reduced costs) and the remainder to be retained by BGE (which benefits shareholders).

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

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

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

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

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

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

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

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

Other Nonregulated Businesses

Net Income

	2002	2001	2000
		(In millions)	
Revenues	$ 537.4	$552.6	$635.2
Operating expenses	505.9	510.7	588.8
Workforce reduction costs	1.0	2.7	—
Impairment losses and other costs	10.8	111.9	—
Depreciation and amortization	16.6	23.2	20.3
Taxes other than income taxes	4.3	3.4	4.3
Net gain on sales of investments and other assets	265.0	6.2	78.1
Income (Loss) from Operations	$ 263.8	$ (93.1)	$ 99.9
Net Income (Loss) Before Cumulative Effect of Change in Accounting Principle	$ 148.0	$ (99.1)	$ 13.8
Cumulative Effect of Change in Accounting Principle	—	8.5	—
Net Income (Loss)	$ 148.0	$ (90.6)	$ 13.8
Net Loss Before Special Items Included in Operations	$ (13.1)	$ (26.8)	$ (33.4)
Net gain on sales of investments and other assets	169.1	1.9	47.2
Workforce reduction costs	(0.7)	(1.7)	—
Costs associated with exit of BGE Home merchandise stores	(6.1)	—	—
Impairment of real estate, senior-living, and international investments	(1.2)	(69.7)	—
Reduction of financial investment	—	(2.8)	—
Net Income (Loss) Before Cumulative Effect of Change in Accounting Principle	148.0	(99.1)	13.8
Cumulative Effect of Change in Accounting Principle	—	8.5	—
Net Income (Loss)	$ 148.0	$ (90.6)	$ 13.8

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

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

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

These increases were partially offset by the following:

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

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

- Our Latin American operation recorded a loss of $43.3 million pre-tax on the sale of our Guatemalan operations.
- We recorded impairment losses of $107.3 million pre-tax related to certain non-core assets.
- Our financial investments operation recorded a $4.6 million pre-tax reduction of its investment in an aircraft due to the decline in value of used airplanes as a result of the September 11, 2001 terrorist attacks and the general downturn in the aviation industry.
- Our financial investments operation had lower earnings due to lower gains on the sale of securities and declining equity values in 2001 compared to 2000.

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

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

As previously discussed in the *Significant Events* section, we decided to sell certain non-core assets and accelerate the exit strategies on other assets that we will continue to hold and own over the next several years. These assets included approximately 1,300 acres of land holdings in various stages of development located in seven sites in the central Maryland region, an operating waste water treatment plant located in Anne Arundel County, Maryland, all of our 18 senior-living facilities and certain international power projects. In 2002, we sold approximately 800 acres of land holdings, all of our senior-living facilities, and a South American generating facility. While our intent is to dispose of these remaining non-core assets, market conditions and other events beyond our control may affect the actual sale of these assets. In addition, a future decline in the fair value of these assets could result in additional losses.

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

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

Consolidated Nonoperating Income and Expenses

Other Income

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

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

Fixed Charges

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

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

Income Taxes

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

Financial Condition

Cash Flows

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

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

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

Security Ratings

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

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

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

Available Sources of Funding

In 2001, we decided to sell certain non-core assets to focus on our core strategies. During 2002, we realized proceeds of over $800 million from the sale of non-core assets and used these funds to repay both short-term and long-term debt. In addition, during 2002, we issued $2.5 billion of debt and established $1.28 billion of credit facilities resulting in $1.7 billion of total credit facilities. We continuously monitor our liquidity requirements and believe that our facilities and access to the capital markets provide sufficient liquidity to meet our business requirements. We discuss our available sources of funding in more detail below.

Constellation Energy

In addition to the $2.5 billion of debt issued in 2002, Constellation Energy has a commercial paper program under which we can issue short-term notes to fund our subsidiaries. At December 31, 2002, we had approximately $1.5 billion of credit under three facilities as discussed below.

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

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

BGE

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

Other Nonregulated Businesses

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

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

Capital Resources

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

We will continue to have cash requirements for:

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

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

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

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

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

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

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

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

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

Capital Requirements

Merchant Energy Business

Our merchant energy business will invest in the following:

- Costs for replacing the steam generators at Calvert Cliffs. In March 2000, we received a license extension from the NRC that extends Calvert Cliffs' operating licenses to 2034 for Unit 1 and 2036 for Unit 2. Replacement of the steam generators will allow us to operate these units through our operating license periods. The 2002 steam generator replacement for Unit 1 was completed at the end of June 2002. We expect the 2003 steam generator replacement to occur during the 2003 refueling outage for Unit 2.
- Continuing requirements, including construction expenditures for improvements to generating plants, nuclear fuel costs, costs of complying with the Environmental Protection Agency (EPA), Maryland, and Pennsylvania nitrogen oxides (NOx) emissions regulations, and enhancements to our information technology infrastructure. We discuss the NOx regulations and timing of expenditures in *Note 11*.

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

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

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

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

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

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

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

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

Regulated Electric and Gas

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

Funding for Capital Requirements

Merchant Energy Business

Funding for the expansion of our merchant energy business is expected from internally generated funds. We also have available sources from commercial paper issuances, issuances of long-term debt and equity, leases, and other financing activities.

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

We expect to fund acquisitions with a mixture of debt and equity with an overall goal of maintaining a strong investment grade credit profile.

BGE

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

Other Nonregulated Businesses

Funding for our other nonregulated businesses is expected from internally generated funds, commercial paper issuances, issuances of long-term debt of Constellation Energy, sales of securities and assets, and/or from time to time equity contributions from Constellation Energy. BGE Home Products & Services can continue to fund capital requirements through sales of receivables.

Our ability to sell or liquidate securities and non-core assets will depend on market conditions, and we cannot give assurances that these sales or liquidations could be made. We discuss our remaining non-core assets and market conditions in the *Results of Operation—Other Nonregulated Businesses* section.

Committed Amounts

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

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

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

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

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

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

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

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

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

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

Liquidity Provisions

We have certain agreements that contain provisions that would require additional collateral upon significant credit rating decreases in the Senior Unsecured Debt of Constellation Energy. Decreases in Constellation Energy's credit ratings would not trigger an early payment on any of our credit facilities. However, under counterparty contracts related to our origination and risk management operation, where we are obligated to post collateral, we estimate that we would have additional collateral obligations based on downgrades to the following credit ratings for our Senior Unsecured Debt:

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

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

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

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

Certain credit facilities of Constellation Energy contain a provision requiring Constellation Energy to maintain a ratio of debt to capitalization equal to or less than 65%. At December 31, 2002, the debt to capitalization ratios as defined in the credit agreements were no greater than 57%.

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

Failure by Constellation Energy, or BGE, to comply with these covenants could result in the maturity of the debt outstanding under these facilities being accelerated. The credit facilities of Constellation Energy contain usual and customary cross-default provisions that apply to defaults on debt by Constellation Energy and certain subsidiaries over a specified threshold. Certain BGE credit facilities also contain usual and customary cross-default provisions that apply to defaults on debt by BGE over a specified threshold. The indentures pursuant to which BGE has issued and outstanding mortgage bonds and subordinated debentures provide that a default under any debt instrument issued under the relevant indenture may cause a default of all debt outstanding under such indenture.

Constellation Energy also provides credit support to Calvert Cliffs and Nine Mile Point to ensure these plants have funds to meet expenses and obligations to safely operate and maintain the plants.

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

Market Risk

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

Interest Rate Risk

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

Principal Payments and Interest Rate Detail by Contractual Maturity Date

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

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

Commodity Risk

We are exposed to the impact of market fluctuations in the price and transportation costs of electricity, natural gas, coal, and other commodities. These risks arise from our ownership and operation of power plants, the load-serving activities of BGE standard offer service and our competitive supply activities, and our mark-to-market origination and risk management activities. We discuss these risks separately for our merchant energy and our regulated businesses below.

Merchant Energy Business

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

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. A number of factors associated with the structure and operation of the electricity markets significantly influence the level and volatility of prices for energy commodities and related derivative products. We use such commodities and contracts in our merchant energy business, and if we have not hedged the associated financial exposure, this price volatility could affect our earnings. These factors include:

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

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

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

Supply and Demand Risk

We are exposed to the risk that available sources of supply may differ from the amount of power demanded by our customers under fixed-price load-serving contracts. During periods of high demand, our power supplies may be insufficient to serve our customers' needs and could require us either to generate power using plants with more costly fuel or to purchase additional energy at higher prices. Alternatively, during periods of low demand, our power supplies may exceed our customers' needs and could result in us selling that excess energy at lower prices. Either of those circumstances could have a negative impact on our earnings.

Operational Risk

Operational risk is the risk that a generating plant will not be available to produce energy and the risks related to physical delivery of energy to meet our customers' needs. For 2003, we expect to use the majority of the generating capacity controlled by our merchant energy business to provide standard offer service to BGE or to serve the load requirements of the sellers of Nine Mile Point. Beginning in July 2002, approximately 1,200 megawatts of industrial customer load moved from BGE's standard offer service to market-based rates. Going forward, our merchant energy business will supply 100% of the standard offer service to BGE through June 30, 2003 and 90% from July 1, 2003 through June 30, 2006.

As a result of declines in BGE's standard offer service load and the 2,900 megawatts of natural gas-fired peaking and combined cycle generating facilities recently constructed, we have a substantial amount of generating capacity that is subject to future changes in wholesale electricity prices and have fuel requirements that are subject to future changes in coal, natural gas, and oil prices. Our power generation facilities purchase fuel under contracts or on the spot market. Fuel prices may be volatile and the price that can be obtained from power sales may not change at the same rate as changes in fuel costs.

Additionally, if one or more of our generating facilities is not able to produce electricity when required due to operational factors, we may have to forego sales opportunities or fulfill fixed-price sale commitments through the operation of other more costly generating facilities or through the purchase of energy in the wholesale market at higher prices.

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

Risk Management

As part of our overall portfolio, we manage the commodity price risk of our competitive supply activities and our electric generation facilities, including power sales, fuel and energy purchases, emission credits, weather risk, and the market risk of outages. In order to manage these risks, we may enter into fixed-price derivative or non-derivative contracts to hedge the variability in future cash flows from forecasted sales of electricity and purchases of fuel and energy, including:

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

The objectives for entering into such hedges include:

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

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

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

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

We measure the sensitivity of our mark-to-market energy contracts to potential changes in market prices using value at risk. Value at risk is a statistical model that attempts to predict risk of loss based on historical market price volatility. We calculate value at risk using a variance/covariance technique that models option positions using a linear approximation of their value. Additionally, we estimate variances and correlation using historical commodity price changes over the most recent rolling three-month period. Our value at risk calculation includes all mark-to-market energy assets and liabilities, including contracts for energy commodities and derivatives that result in physical settlement and contracts that require cash settlement.

The value at risk calculation does not include market risks associated with activities that are subject to accrual accounting, primarily our generating facilities and our competitive supply load-serving activities. We manage these risks by monitoring our fuel and energy purchase requirements and our estimated contract sales volumes compared to associated supply arrangements. We also engage in hedging activities to manage these risks. We describe those risks and our hedging activities earlier in this section.

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

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

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

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

Regulated Electric Business

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

Regulated Gas Business
Our regulated gas business may enter into gas futures, options, and swaps to hedge its price risk under our market-based rate incentive mechanism and our off-system gas sales program. We discuss this further in *Note 1*. At December 31, 2002 and 2001, our exposure to commodity price risk for our regulated gas business was not material.

Credit Risk
We are exposed to credit risk, primarily through our merchant energy business. Credit risk is the loss that may result from a counterparty's nonperformance. We use credit policies to manage our credit risk, including utilizing an established credit approval process, monitoring counterparty limits, employing credit mitigation measures such as margin, collateral, or prepayment arrangements, and using master netting agreements. We measure credit risk as the replacement cost for open energy commodity and derivative positions (both mark-to-market and accrual) plus amounts owed from counterparties for settled transactions. The replacement cost of open positions represents unrealized gains, net of any unrealized losses, where we have a legally enforceable right of setoff.

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

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

Additionally, if a counterparty were to default and we were to liquidate all contracts with that entity, our credit loss would include the loss in value of mark-to-market contracts, the amount owed for settled transactions, and additional payments, if any, we would have to make to settle unrealized losses on accrual contracts.

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

A hypothetical 10% decrease in equity prices would result in an approximate $65 million reduction in the fair value of our financial investments that are classified as trading or available-for-sale securities. In 2002, the value of our defined benefit pension plan assets decreased by approximately $90 million due to declines in the markets in which plan assets are invested. We describe our financial investments in more detail in *Note 4*, and our pension plans in *Note 6*.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

The information required by this item with respect to market risk is set forth in *Item 7* of Part II of this Form 10-K under the heading *Market Risk*.

REPORT OF MANAGEMENT

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

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

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

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

E. Follin Smith
Senior Vice-President & Chief Financial Officer

REPORT OF INDEPENDENT ACCOUNTANTS

To the Shareholders of Constellation Energy Group, Inc. and Baltimore Gas and Electric Company

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a) 1. present fairly, in all material respects, the financial position of Constellation Energy Group, Inc. and Subsidiaries and of Baltimore Gas and Electric Company and Subsidiaries at December 31, 2002 and 2001, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2002 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a) 2. of this Form 10-K presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and the financial statement schedule are the responsibility of the Companies' management; our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

We have also previously audited, in accordance with auditing standards generally accepted in the United States of America, the consolidated balance sheets and statement of capitalization of Constellation Energy Group, Inc. and Subsidiaries and of Baltimore Gas and Electric Company and Subsidiaries as of December 31, 2000, 1999 and 1998, and the related consolidated statements of income, cash flows, and common shareholders' equity and comprehensive income for the years ended December 31, 1999 and 1998 (none of which are presented herein); and we expressed unqualified opinions on those consolidated financial statements. In our opinion, the information set forth in the Summary of Operations and Summary of Financial Condition of Constellation Energy Group, Inc. included in the Selected Financial Data for each of the five years in the period ended December 31, 2002, and the information set forth in the Summary of Operations and Summary of Financial Condition of Baltimore Gas and Electric Company included in the Selected Financial Data for each of the five years in the period ended December 31, 2002, is fairly stated, in all material respects, in relation to the consolidated financial statements from which it has been derived.

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

PricewaterhouseCoopers LLP
Baltimore, Maryland
January 29, 2003

CONSOLIDATED STATEMENTS OF INCOME

Constellation Energy Group, Inc. and Subsidiaries

Year Ended December 31,	2002	2001	2000
	(In millions, except per share amounts)		
Revenues			
Nonregulated revenues	$2,166.9	$1,164.9	$1,035.9
Regulated electric revenues	1,965.6	2,039.6	2,134.7
Regulated gas revenues	570.5	674.3	603.8
Total revenues	4,703.0	3,878.8	3,774.4
Expenses			
Operating expenses	3,049.9	2,392.2	2,311.4
Workforce reduction costs	62.8	105.7	7.0
Impairment losses and other costs	25.2	158.8	—
Contract termination related costs	—	224.8	—
Depreciation and amortization	481.0	419.1	470.0
Taxes other than income taxes	259.2	226.6	221.5
Total expenses	3,878.1	3,527.2	3,009.9
Net Gain on Sales of Investments and Other Assets	261.3	6.2	78.1
Income from Operations	1,086.2	357.8	842.6
Other Income	30.5	1.3	4.2
Fixed Charges			
Interest expense	312.3	283.2	282.4
Interest capitalized and allowance for borrowed funds used during construction	(44.0)	(57.6)	(24.2)
BGE preference stock dividends	13.2	13.2	13.2
Total fixed charges	281.5	238.8	271.4
Income Before Income Taxes	835.2	120.3	575.4
Income Taxes	309.6	37.9	230.1
Income Before Cumulative Effect of Change in Accounting Principle	525.6	82.4	345.3
Cumulative Effect of Change in Accounting Principle, Net of Income Taxes of $5.6 (see Note 1)	—	8.5	—
Net Income	$ 525.6	$ 90.9	$ 345.3
Earnings Applicable to Common Stock	$ 525.6	$ 90.9	$ 345.3
Average Shares of Common Stock Outstanding	164.2	160.7	150.0
Earnings Per Common Share and Earnings Per Common Share—Assuming Dilution Before Cumulative Effect of Change in Accounting Principle	$ 3.20	$ .52	$ 2.30
Cumulative Effect of Change in Accounting Principle	—	.05	—
Earnings Per Common Share and Earnings Per Common Share—Assuming Dilution	$ 3.20	$ .57	$ 2.30

See Notes to Consolidated Financial Statements.

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

CONSOLIDATED BALANCE SHEETS

Constellation Energy Group, Inc. and Subsidiaries

At December 31,	2002	2001
	(In millions)	
Assets		
Current Assets		
Cash and cash equivalents	$ 615.0	$ 72.4
Accounts receivable (net of allowance for uncollectibles of $41.9 and $22.8, respectively)	1,247.3	738.9
Trading securities	77.1	178.2
Mark-to-market energy assets	144.0	398.4
Risk management assets	72.3	65.2
Fuel stocks	126.5	110.2
Materials and supplies	208.6	210.2
Prepaid taxes other than income taxes	57.1	64.7
Other	153.9	58.0
Total current assets	2,701.8	1,896.2
Investments and Other Assets		
Real estate projects and investments	86.1	210.7
Investments in qualifying facilities and power projects	439.2	499.1
Investment in Orion Power Holdings, Inc.	—	442.5
Financial investments	36.9	60.7
Nuclear decommissioning trust funds	645.4	683.5
Mark-to-market energy assets	1,348.2	1,819.8
Risk management assets	88.8	77.6
Goodwill	115.9	—
Other	167.8	132.8
Total investments and other assets	2,928.3	3,926.7
Property, Plant and Equipment		
Regulated property, plant and equipment		
Plant in service	4,952.4	4,862.4
Construction work in progress	118.3	81.8
Plant held for future use	4.5	4.5
Total regulated property, plant and equipment	5,075.2	4,948.7
Nonregulated generation property, plant and equipment	6,811.9	6,538.7
Other nonregulated property, plant and equipment	242.0	192.9
Nuclear fuel (net of amortization)	224.8	174.8
Accumulated depreciation	(4,396.8)	(4,161.8)
Net property, plant and equipment	7,957.1	7,693.3
Deferred Charges		
Regulatory assets (net)	405.7	463.8
Other	136.0	129.4
Total deferred charges	541.7	593.2
Total Assets	$14,128.9	$ 14,109.4

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

CONSOLIDATED BALANCE SHEETS

Constellation Energy Group, Inc. and Subsidiaries

At December 31,	2002	2001
	(In millions)	
Liabilities and Equity		
Current Liabilities		
Short-term borrowings	$ 10.5	$ 975.0
Current portion of long-term debt	426.2	1,406.7
Accounts payable	943.4	523.3
Mark-to-market energy liabilities	94.1	323.3
Risk management liabilities	20.1	11.7
Dividends declared	42.8	23.0
Accrued interest	95.5	57.7
Other	392.8	250.4
Total current liabilities	2,025.4	3,571.1
Deferred Credits and Other Liabilities		
Deferred income taxes	1,330.7	1,431.0
Mark-to-market energy liabilities	881.5	1,476.5
Risk management liabilities	149.5	12.5
Net pension liability	334.6	215.5
Postretirement and postemployment benefits	352.8	330.9
Deferred investment tax credits	85.7	93.4
Other	197.2	130.7
Total deferred credits and other liabilities	3,332.0	3,690.5
Capitalization (See Statement of Capitalization)		
Long-term debt	4,613.9	2,712.5
Minority interests	105.3	101.7
BGE preference stock not subject to mandatory redemption	190.0	190.0
Common shareholders' equity	3,862.3	3,843.6
Total capitalization	8,771.5	6,847.8
Commitments, Guarantees, and Contingencies (see Note 11)		
Total Liabilities and Equity	$14,128.9	$ 14,109.4

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

CONSOLIDATED STATEMENTS OF CASH FLOWS

Constellation Energy Group, Inc. and Subsidiaries

Year Ended December 31,	2002	2001	2000
		(In millions)	
Cash Flows From Operating Activities			
Net income	$ 525.6	$ 90.9	$ 345.3
Adjustments to reconcile to net cash provided by operating activities			
Cumulative effect of change in accounting principle	—	(8.5)	—
Depreciation and amortization	548.0	468.9	524.8
Deferred income taxes	148.3	(26.5)	42.1
Investment tax credit adjustments	(7.9)	(8.1)	(8.4)
Deferred fuel costs	23.9	37.6	2.8
Pension and postemployment benefits	(116.2)	55.3	27.9
Net gain on sales of investments and other assets	(261.3)	(6.2)	(78.1)
Workforce reduction costs	62.8	105.7	7.0
Impairment losses and other costs	25.2	158.8	—
Contract termination related costs	—	26.2	—
Deregulation transition cost	—	—	24.0
Equity in earnings of affiliates less than (in excess of) dividends received	67.0	2.0	(5.3)
Changes in			
Accounts receivable	(236.8)	53.7	(214.1)
Mark-to-market energy assets and liabilities	(133.7)	109.5	(379.6)
Risk management assets and liabilities	58.6	(93.2)	—
Materials, supplies and fuel stocks	(11.7)	(90.9)	14.5
Other current assets	130.3	(20.5)	(31.1)
Accounts payable	188.4	(226.7)	384.9
Other current liabilities	50.4	7.8	21.3
Other	(40.9)	(62.5)	172.9
Net cash provided by operating activities	1,020.0	573.3	850.9
Cash Flows From Investing Activities			
Purchases of property, plant and equipment	(831.9)	(1,302.5)	(1,067.0)
Acquisitions, net of cash acquired	(221.4)	(382.7)	—
Contributions to nuclear decommissioning trust funds	(17.6)	(22.0)	(13.2)
Payments for structured deal fees	(51.4)	—	—
Sale of (investment in) Orion	454.1	26.2	(101.5)
Sale of investments and other assets	383.9	260.9	169.9
Purchases of marketable equity securities	(0.2)	(33.2)	(80.8)
Other investments	(35.3)	(19.4)	(13.9)
Net cash used in investing activities	(319.8)	(1,472.7)	(1,106.5)
Cash Flows From Financing Activities			
Net issuance (maturity) of short-term borrowings	(964.5)	731.4	(127.9)
Proceeds from issuance of			
Long-term debt	2,529.3	1,175.2	1,374.0
Common stock	28.5	504.4	35.9
Repayment of long-term debt	(1,627.7)	(1,510.2)	(697.0)
Common stock dividends paid	(137.8)	(120.7)	(250.7)
Other	14.6	9.0	11.3
Net cash (used in) provided by financing activities	(157.6)	789.1	345.6
Net Increase (Decrease) in Cash and Cash Equivalents	542.6	(110.3)	90.0
Cash and Cash Equivalents at Beginning of Year	72.4	182.7	92.7
Cash and Cash Equivalents at End of Year	$ 615.0	$ 72.4	$ 182.7
Other Cash Flow Information:			
Cash paid during the year for:			
Interest (net of amounts capitalized)	$ 230.5	$ 238.3	$ 268.2
Income taxes	$ 157.8	$ 101.5	$ 184.7

Non-Cash Transaction:

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

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

CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDERS' EQUITY AND COMPREHENSIVE INCOME

Constellation Energy Group, Inc. and Subsidiaries

Years Ended December 31, 2002, 2001, and 2000	Common Stock Shares	Common Stock Amount	Retained Earnings	Accumulated Other Comprehensive Income	Total Amount
	(Dollar amounts in millions, number of shares in thousands)				
Balance at December 31, 1999	149,556	$1,494.0	$1,499.1	$ 24.4	$3,017.5
Comprehensive Income					
Net income			345.3		345.3
Other comprehensive income (OCI)					
Reclassification of net gain on sales of securities from OCI to net income, net of taxes of $18.4				(28.1)	(28.1)
Net unrealized gain on securities, net of taxes of $27.9				46.7	46.7
Total Comprehensive Income					363.9
Common stock dividend declared ($1.68 per share)			(251.8)		(251.8)
Common stock issued	976	35.9			35.9
Other		8.8	(0.3)		8.5
Balance at December 31, 2000	150,532	1,538.7	1,592.3	43.0	3,174.0
Comprehensive Income					
Net income			90.9		90.9
Other comprehensive income					
Cumulative effect of change in accounting principle, net of taxes of $22.6				(35.5)	(35.5)
Reclassification of net gain on sales of securities from OCI to net income, net of taxes of $15.7				(24.0)	(24.0)
Net unrealized gain on securities, net of taxes of $87.5				148.5	148.5
Net unrealized gain on hedging instruments, net of taxes of $65.6				102.6	102.6
Minimum pension liability, net of taxes of $29.3				(44.7)	(44.7)
Total Comprehensive Income					237.8
Common stock dividend declared ($.48 per share)			(77.1)		(77.1)
Common stock issued	13,176	504.4			504.4
Other		(0.9)	5.4		4.5
Balance at December 31, 2001	163,708	2,042.2	1,611.5	189.9	3,843.6
Comprehensive Income					
Net income			525.6		525.6
Other comprehensive income					
Reclassification of net gain on sales of securities from OCI to net income, net of taxes of $87.7				(152.8)	(152.8)
Reclassification of net gains on hedging instruments from OCI to net income, net of taxes of $10.9				(17.8)	(17.8)
Net unrealized loss on securities, net of taxes of $28.6				(43.2)	(43.2)
Net unrealized loss on hedging instruments, net of taxes of $31.7				(52.2)	(52.2)
Minimum pension liability, net of taxes of $77.2				(118.1)	(118.1)
Total Comprehensive Income					141.5
Common stock dividend declared ($.96 per share)			(157.6)		(157.6)
Common stock issued	1,135	28.5			28.5
Other		8.2	(1.9)		6.3
Balance at December 31, 2002	164,843	$2,078.9	$1,977.6	$(194.2)	$3,862.3

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

CONSOLIDATED STATEMENTS OF CAPITALIZATION

Constellation Energy Group, Inc. and Subsidiaries

At December 31,	2002	2001
	(In millions)	
Long-Term Debt		
Long-term debt of Constellation Energy		
Floating rate notes, due January 17, 2002	$ —	$ 635.0
7⅞% Notes, due April 1, 2005	300.0	300.0
6.35% Fixed Rate Notes, due April 1, 2007	600.0	—
6.125% Fixed Rate Notes, due September 1, 2009	500.0	—
7.00% Fixed Rate Notes, due April 1, 2012	700.0	—
7.60% Fixed Rate Notes, due April 1, 2032	700.0	—
Total long-term debt of Constellation Energy	2,800.0	935.0
Long-term debt of nonregulated businesses		
Tax-exempt debt transferred from BGE effective July 1, 2000		
Pollution control loan, due July 1, 2011	36.0	36.0
Port facilities loan, due June 1, 2013	48.0	48.0
Adjustable rate pollution control loan, due July 1, 2014	20.0	20.0
5.55% Pollution control revenue refunding loan, due July 15, 2014	47.0	47.0
Economic development loan, due December 1, 2018	35.0	35.0
6.00% Pollution control revenue refunding loan, due April 1, 2024	75.0	75.0
Floating rate pollution control loan, due June 1, 2027	8.8	8.8
5½% Installment series, due July 15, 2002	—	6.7
District Cooling facilities loan, due December 1, 2031	25.0	25.0
Loans under revolving credit agreements	51.7	46.0
11% Installment note, due November 7, 2006	—	388.1
Mortgage and construction loans		
Floating rate mortgage notes and construction loans, due through 2005	—	13.8
4.25% Mortgage note, due March 15, 2009	3.3	19.7
Total long-term debt of nonregulated businesses	349.8	769.1
First Refunding Mortgage Bonds of BGE		
7¼% Series, due July 1, 2002	—	124.0
6½% Series, due February 15, 2003	124.8	124.8
6⅛% Series, due July 1, 2003	124.9	124.9
5½% Series, due April 15, 2004	125.0	125.0
Remarketed floating rate series, due September 1, 2006	111.5	111.5
7½% Series, due January 15, 2007	123.5	123.5
6⅝% Series, due March 15, 2008	124.9	124.9
7½% Series, due March 1, 2023	98.1	98.1
7½% Series, due April 15, 2023	72.2	84.0
Total First Refunding Mortgage Bonds of BGE	904.9	1,040.7
Other long-term debt of BGE		
5.25% Notes, due December 15, 2006	300.0	300.0
Floating rate reset notes, due February 5, 2002	—	200.0
Medium-term notes, Series B	12.1	23.1
Medium-term notes, Series C	25.5	25.5
Medium-term notes, Series D	68.0	68.0
Medium-term notes, Series E	199.5	200.0
Medium-term notes, Series G	140.0	140.0
6.75% Remarketable or redeemable securities, due December 15, 2012	—	173.0
Total other long-term debt of BGE	745.1	1,129.6
BGE obligated mandatorily redeemable trust preferred securities of subsidiary trust holding solely 7.16% deferrable interest subordinated debentures due June 30, 2038	250.0	250.0
Unamortized discount and premium	(9.7)	(5.2)
Current portion of long-term debt	(426.2)	(1,406.7)
Total long-term debt	$4,613.9	$2,712.5

See Notes to Consolidated Financial Statements.

continued on next page

CONSOLIDATED STATEMENTS OF CAPITALIZATION

Constellation Energy Group, Inc. and Subsidiaries

At December 31,	2002	2001
	(In millions)	
Minority Interests	$ 105.3	$ 101.7
BGE Preference Stock		
Cumulative preference stock not subject to mandatory redemption, 6,500,000 shares authorized		
7.125%, 1993 Series, 400,000 shares outstanding, not callable prior to July 1, 2003	40.0	40.0
6.97%, 1993 Series, 500,000 shares outstanding, not callable prior to October 1, 2003	50.0	50.0
6.70%, 1993 Series, 400,000 shares outstanding, not callable prior to January 1, 2004	40.0	40.0
6.99%, 1995 Series, 600,000 shares outstanding, not callable prior to October 1, 2005	60.0	60.0
Total preference stock not subject to mandatory redemption	190.0	190.0
Common Shareholders' Equity		
Common stock without par value, 250,000,000 shares authorized; 164,842,708 and 163,707,950 shares issued and outstanding at December 31, 2002 and 2001, respectively. (At December 31, 2002, 18,000,000 shares were reserved for the long-term incentive plans, 11,451,868 shares were reserved for the Shareholder Investment Plan, 1,806,100 shares were reserved for the continuous offering programs, and 1,505,863 shares were reserved for the employee savings plan.)	2,078.9	2,042.2
Retained earnings	1,977.6	1,611.5
Accumulated other comprehensive (loss) income	(194.2)	189.9
Total common shareholders' equity	3,862.3	3,843.6
Total Capitalization	$8,771.5	$6,847.8

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

CONSOLIDATED STATEMENTS OF INCOME

Baltimore Gas and Electric Company and Subsidiaries

Year Ended December 31,	2002	2001	2000
		(In millions)	
Revenues			
Electric revenues	$1,966.0	$2,040.0	$2,135.2
Gas revenues	581.3	680.7	611.6
Total revenues	2,547.3	2,720.7	2,746.8
Expenses			
Operating Expenses			
Electric fuel and purchased energy	1,080.7	1,192.8	870.7
Gas purchased for resale	316.7	401.3	350.6
Operations and maintenance	355.3	363.0	547.4
Workforce reduction costs	35.3	57.0	7.0
Depreciation and amortization	221.6	221.0	366.1
Taxes other than income taxes	171.4	173.8	192.6
Total expenses	2,181.0	2,408.9	2,334.4
Income from Operations	366.3	311.8	412.4
Other Income	10.7	0.4	7.5
Fixed Charges			
Interest expense	142.1	156.2	187.2
Allowance for borrowed funds used during construction	(1.5)	(1.6)	(3.2)
Total fixed charges	140.6	154.6	184.0
Income Before Income Taxes	236.4	157.6	235.9
Income Taxes			
Current	67.4	62.4	142.1
Deferred	28.0	0.2	(44.4)
Investment tax credit adjustments	(2.1)	(2.3)	(5.3)
Total income taxes	93.3	60.3	92.4
Net Income	143.1	97.3	143.5
Preference Stock Dividends	13.2	13.2	13.2
Earnings Applicable to Common Stock	$ 129.9	$ 84.1	$ 130.3

See Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

Baltimore Gas and Electric Company and Subsidiaries

At December 31,	2002	2001
	(In millions)	
Assets		
Current Assets		
Cash and cash equivalents	$ 10.2	$ 37.4
Accounts receivable (net of allowance for uncollectibles of $11.5 and $13.4, respectively)	357.5	295.2
Investment in cash pool, affiliated company	338.1	439.1
Accounts receivable, affiliated companies	131.2	63.4
Fuel stocks	40.6	52.3
Materials and supplies	31.8	33.1
Prepaid taxes other than income taxes	42.0	43.8
Other	10.3	36.3
Total current assets	961.7	1,000.6
Other Assets		
Receivable, affiliated company	63.3	183.3
Other	85.9	74.5
Total other assets	149.2	257.8
Utility Plant		
Plant in service		
Electric	3,422.3	3,349.9
Gas	1,041.0	1,014.4
Common	489.1	498.1
Total plant in service	4,952.4	4,862.4
Accumulated depreciation	(1,851.4)	(1,751.4)
Net plant in service	3,101.0	3,111.0
Construction work in progress	118.3	81.8
Plant held for future use	4.5	4.5
Net utility plant	3,223.8	3,197.3
Deferred Charges		
Regulatory assets (net)	405.7	463.8
Other	39.5	35.0
Total deferred charges	445.2	498.8
Total Assets	$ 4,779.9	$ 4,954.5

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

CONSOLIDATED BALANCE SHEETS

Baltimore Gas and Electric Company and Subsidiaries

At December 31,	2002	2001
	(In millions)	
Liabilities and Equity		
Current Liabilities		
Current portions of long-term debt	$ 420.7	$ 666.3
Accounts payable	103.2	63.6
Accounts payable, affiliated companies	85.6	92.6
Customer deposits	54.2	50.0
Accrued taxes	9.0	7.6
Accrued interest	31.4	37.0
Accrued vacation costs	19.5	21.7
Other	30.2	39.2
Total current liabilities	753.8	978.0
Deferred Credits and Other Liabilities		
Deferred income taxes	528.9	503.1
Postretirement and postemployment benefits	278.0	266.1
Deferred investment tax credits	20.5	22.7
Decommissioning of federal uranium enrichment facilities	14.6	19.3
Other	13.9	17.2
Total deferred credits and other liabilities	855.9	828.4
Long-term Debt		
First refunding mortgage bonds of BGE	904.9	1,040.7
Other long-term debt of BGE	745.1	1,129.6
Company obligated mandatorily redeemable trust preferred securities of subsidiary trust holding solely 7.16% debentures of BGE due June 30, 2038	250.0	250.0
Long-term debt of nonregulated businesses	25.0	71.0
Unamortized discount and premium	(5.2)	(3.3)
Current portion of long-term debt	(420.7)	(666.3)
Total long-term debt	1,499.1	1,821.7
Minority Interest	19.4	5.0
Preference Stock Not Subject to Mandatory Redemption	190.0	190.0
Common Shareholder's Equity		
Common stock	912.2	711.9
Retained earnings	549.5	419.5
Total common shareholder's equity	1,461.7	1,131.4
Commitments, Guarantees, and Contingencies (see Note 11)		
Total Liabilities and Equity	$ 4,779.9	$ 4,954.5

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

CONSOLIDATED STATEMENTS OF CASH FLOWS

Baltimore Gas and Electric Company and Subsidiaries

Year Ended December 31,	2002	2001	2000
		(In millions)	
Cash Flows From Operating Activities			
Net income	$ 143.1	$ 97.3	$ 143.5
Adjustments to reconcile to net cash provided by operating activities			
Depreciation and amortization	224.4	223.3	393.6
Deferred income taxes	28.0	0.2	(44.4)
Investment tax credit adjustments	(2.1)	(2.3)	(5.3)
Deferred fuel costs	23.9	37.6	2.8
Pension and postemployment benefits	(40.7)	14.7	16.1
Allowance for equity funds used during construction	(2.8)	(3.0)	(2.6)
Workforce reduction costs	35.3	57.0	7.0
Changes in			
Accounts receivable	(62.3)	117.8	(101.4)
Receivables, affiliated companies	52.2	(113.5)	(128.7)
Materials, supplies and fuel stocks	13.0	(14.0)	11.1
Other current assets	27.8	(30.5)	31.8
Accounts payable	39.6	(55.7)	(88.6)
Accounts payable, affiliated companies	(7.0)	(10.9)	98.8
Other current liabilities	(11.2)	(7.7)	(7.1)
Other	33.2	61.5	68.1
Net cash provided by operating activities	494.4	371.8	394.7
Cash Flows From Investing Activities			
Utility construction expenditures (excluding equity portion of AFC)	(216.7)	(236.4)	(309.5)
Investment in cash pool at parent	101.0	(441.1)	2.0
Nuclear fuel expenditures	—	—	(39.5)
Contributions to nuclear decommissioning trust fund	—	—	(8.8)
Other	(17.0)	(20.9)	0.1
Net cash used in investing activities	(132.7)	(698.4)	(355.7)
Cash Flows From Financing Activities			
Net maturity of short-term borrowings	—	(32.1)	(96.9)
Proceeds from issuance of long-term debt	—	532.1	377.3
Repayment of long-term debt	(575.5)	(394.1)	(121.7)
Preference stock dividends paid	(13.2)	(13.2)	(13.2)
Distribution from (to) parent	200.0	250.0	(188.5)
Other	(0.2)	—	1.8
Net cash (used in) provided by financing activities	(388.9)	342.7	(41.2)
Net (Decrease) Increase in Cash and Cash Equivalents	(27.2)	16.1	(2.2)
Cash and Cash Equivalents at Beginning of Year	37.4	21.3	23.5
Cash and Cash Equivalents at End of Year	$ 10.2	$ 37.4	$ 21.3
Other Cash Flow Information			
Cash paid during the year for:			
Interest (net of amounts capitalized)	$ 147.5	$ 162.0	$ 184.7
Income taxes	$ 36.6	$ 102.8	$ 127.6

Noncash Investing and Financing Activities:

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

See Notes to Consolidated Financial Statements.

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

1 Significant Accounting Policies

Nature of Our Business

Constellation Energy Group, Inc. (Constellation Energy) is a North American energy company that conducts its business through various subsidiaries including a merchant energy business and Baltimore Gas and Electric Company (BGE). Our merchant energy business is a competitive provider of energy solutions for large customers. BGE is a regulated electric and gas public transmission and distribution utility company with a service territory that covers the City of Baltimore and all or part of ten counties in central Maryland. We describe our operating segments in *Note 3*.

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

Consolidation Policy

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

Consolidation

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

The Equity Method

We usually use the equity method to report investments, corporate joint ventures, partnerships, and affiliated companies (including qualifying facilities and power projects) where we hold a 20% to 50% voting interest. Under the equity method, we report:

- our interest in the entity as an investment in our Consolidated Balance Sheets, and
- our percentage share of the earnings from the entity in our Consolidated Statements of Income.

The only time we do not use this method is if we can exercise control over the operations and policies of the company. If we have control, accounting rules require us to use consolidation.

The Cost Method

We usually use the cost method if we hold less than a 20% voting interest in an investment. Under the cost method, we report our investment at cost in our Consolidated Balance Sheets. The only time we do not use this method is when we can exercise significant influence over the operations and policies of the company. If we have significant influence, accounting rules require us to use the equity method.

Regulation of Utility Business

The Maryland Public Service Commission (Maryland PSC) and the Federal Energy Regulatory Commission (FERC) provide the final determination of the rates we charge our customers for our regulated businesses. Generally, we use the same accounting policies and practices used by nonregulated companies for financial reporting under accounting principles generally accepted in the United States of America. However, sometimes the Maryland PSC orders an accounting treatment different from that used by nonregulated companies to determine the rates we charge our customers. When this happens, we must defer (include as an asset or liability in our Consolidated Balance Sheets and exclude from our Consolidated Statements of Income) certain utility expenses and income as regulatory assets and liabilities. We have recorded these regulatory assets and liabilities in our Consolidated Balance Sheets in accordance with Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulation.*

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

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

Use of Accounting Estimates

Management makes estimates and assumptions when preparing financial statements under accounting principles generally accepted in the United States of America. These estimates and assumptions affect various matters, including:

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

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

Reclassifications

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

Revenues

Nonregulated Businesses

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

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

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

- Close-out reserve—this reserve represents the estimated cost to close out or sell to a third-party open mark-to-market positions. This reserve has the effect of valuing "long" positions at the bid price and "short" positions at the offer price. We compute this reserve based on our estimate of the bid/offer spread for each commodity and option price and the absolute quantity of our open positions for each year. Effective July 1, 2002, to the extent that we are not able to obtain market information for similar contracts, the close-out reserve is equivalent to the initial contract margin, thereby recording no gain or loss at inception. The level of total close-out reserves increases as we have larger unhedged positions, bid-offer spreads increase, or market information is not available, and it decreases as we reduce our unhedged positions, bid-offer spreads decrease, or market information becomes available.
- Credit-spread adjustment—for risk management purposes, we compute the value of our mark-to-market assets and liabilities using a risk-free discount rate. In order to compute fair value for financial reporting purposes, we adjust the value of our mark-to-market assets to reflect the credit-worthiness of each individual counterparty based upon published credit ratings, where available, or equivalent internal credit ratings and associated default probability percentages. We compute this reserve by applying the appropriate default probability percentage to our outstanding credit exposure, net of collateral, for each counterparty.

Mark-to-market revenues include:

- gains or losses on new transactions at origination to the extent permitted by applicable accounting rules,
- unrealized gains and losses from changes in the fair value of open positions,
- net gains and losses from realized transactions, and
- changes in reserves.

We record the changes in mark-to-market energy assets and liabilities on a net basis in "Nonregulated revenues" in our Consolidated Statements of Income. At December 31, 2002, mark-to-market energy assets and liabilities consist of a combination of energy and energy-related derivative and non-derivative contracts. While some of these contracts represent commodities or instruments for which prices are available from external sources, other commodities and certain contracts are not actively traded and are valued using modeling techniques to determine expected future market prices, contract quantities, or both. The market prices and quantities used to determine fair value reflect management's best estimate considering various factors, including closing exchange and over-the-counter quotations, time value, and volatility factors. However, future market prices and actual quantities will vary from those used in recording mark-to-market energy assets and liabilities, and it is possible that such variations could be material.

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

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

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

Regulated Utility

We record utility revenues when we provide service to customers.

Fuel and Purchased Energy Costs

We incur costs for:

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

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

Fuel Used to Generate Electricity and Purchases of Electricity From Others

We assemble a variety of power supply resources, including baseload, intermediate, and peaking plants that we own, as well as a variety of power supply contracts that may have similar characteristics, in order to enable us to meet our customers' energy requirements, which vary on an hourly basis. We purchase power when our load-serving requirements exceed the amount of power available from our supply resources or when it is more economic to do so than to operate our power plants. The amount of power purchased depends on a number of factors, including the capacity and availability of our power plants, the level of customer demand, and the relative economics of generating power versus purchasing power from the spot market.

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

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

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

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

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

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

Natural Gas

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

Risk Management and Hedging Activities

Market Risks

We are exposed to market risk, including changes in interest rates and the impact of market fluctuations in the price and transportation costs of electricity, natural gas, and other commodities as discussed further in *Note 12*. SFAS No. 133, as amended by SFAS No. 138, *Accounting for Certain Derivative Instruments and Certain Hedging Activities*, requires that we recognize all derivatives not qualifying for the normal purchase and normal sale exemption in our Consolidated Balance Sheets at fair value. Changes in the value of derivatives that are not hedges must be recorded in earnings. Under SFAS No. 133, changes in the value of derivatives designated as cash-flow hedges that are effective in offsetting the variability in cash flows of forecasted transactions are recognized in other comprehensive income until the forecasted transactions occur. The ineffective portion of changes in fair value of derivatives used as cash-flow hedges is immediately recognized in earnings.

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

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

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

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

Interest Rate Swaps

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

Commodity Prices

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

Merchant Energy Business

Our origination and risk management operation manages market risk on a portfolio basis, subject to established risk management policies. Our origination and risk management operation may enter into fixed-price derivative or non-derivative contracts to hedge the variability in future cash flows from forecasted sales of energy and purchases of fuel.

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

Regulated Gas Business

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

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

Credit Risk

Credit risk is the loss that may result from counterparty non-performance. We are exposed to credit risk, primarily through our merchant energy business. We use credit policies to manage our credit risk, including utilizing an established credit approval process, monitoring counterparty limits, employing credit mitigation measures such as margin, collateral or prepayment arrangements, and using master netting agreements. We measure credit risk as the replacement cost for open energy commodity and derivative positions (both mark-to-market and accrual) plus amounts owed from counterparties for settled transactions. The replacement cost of open positions represents unrealized gains, net of any unrealized losses, where we have a legally enforceable right of setoff.

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

Additionally, if a counterparty were to default and we were to liquidate all contracts with that entity, our credit loss would include the loss in value of mark-to-market contracts, the amount owed for settled transactions, and additional payments, if any, we would have to make to settle unrealized losses on accrual contracts.

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

Taxes

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

Income Tax Expense

We have two categories of income taxes—current and deferred. We describe each of these below:

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

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

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

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

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

We also pay Maryland public service company franchise tax on transmission, distribution, and delivery of electricity and natural gas. We include the franchise tax in "Taxes other than income taxes" in our Consolidated Statements of Income.

Earnings Per Share
Basic earnings per common share (EPS) is computed by dividing earnings applicable to common stock by the weighted-average number of common shares outstanding for the year. Diluted EPS reflects the potential dilution of common stock equivalent shares that could occur if securities or other contracts to issue common stock were exercised or converted into common stock. Our dilutive common stock equivalent shares consist of stock options. Stock options to purchase approximately 4.1 million shares in 2002, approximately 0.1 million shares in 2001, and approximately 1.4 million shares in 2000 were not dilutive and were excluded from the computation of diluted EPS for these respective years.

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

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

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

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

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

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

- in 2002, $6.1 million, after-tax, or $10.1 million pre-tax comprised of $3.0 million of pre-tax expense for certain stock options, $6.6 million for restricted stock, and $0.5 million for equity grants,
- in 2001, a $(6.1) million, after-tax, or $(10.1) million pre-tax reversal of expense for restricted stock as a result of non-attainment of performance criteria, and
- in 2000, $9.8 million, after-tax, or $16.3 million pre-tax for restricted stock grants.

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

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

Real Estate Projects and Investments

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

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

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

Financial Investments and Trading Securities

In *Note 4*, we summarize the financial investments that are in our Consolidated Balance Sheets.

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

Trading Securities

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

Available-for-Sale Securities

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

In addition, our other nonregulated businesses classified some of their investments in marketable equity securities as available-for-sale securities.

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

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

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

We determine if long-lived assets are impaired by comparing their undiscounted expected future cash flows to their carrying amount in our accounting records. We would record an impairment loss if the undiscounted expected future cash flows from an asset were less than the carrying amount of the asset. We are also required to evaluate our equity-method and cost-method investments (for example, in partnerships that own power projects) for impairment. APB No. 18, *The Equity Method of Accounting for Investments in Common Stock*, provides the accounting for these investments. The standard for determining whether an impairment must be recorded under APB No. 18 is whether the investment has experienced a loss in value that is considered an "other than a temporary" decline in value.

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

Goodwill

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

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

We report our property, plant and equipment at its original cost, unless impaired under the provisions of SFAS No. 144.

Our original costs include:

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

We own an undivided interest in the Keystone and Conemaugh electric generating plants in Western Pennsylvania, as well as in the transmission line that transports the plants' output to the joint owners' service territories. Our ownership interests in these plants are 20.99% in Keystone and 10.56% in Conemaugh. These ownership interests represented a net investment of $168 million at December 31, 2002 and $148 million at December 31, 2001. Each owner is responsible for financing its proportionate share of the plants' working funds. Working funds are used for operating expenses and capital expenditures. Operating expenses related to these plants are included in "Operating Expenses" in our Consolidated Statements of Income. Capital costs related to these plants are included in "Nonregulated generation property, plant and equipment" in our Consolidated Balance Sheets.

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

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

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

Depreciation Expense

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

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

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

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

Amortization Expense

Amortization is an accounting process of reducing an amount in our Consolidated Balance Sheets evenly over a period of time that approximates the useful life of the related item. When we reduce amounts in our Consolidated Balance Sheets, we increase amortization expense in our Consolidated Statements of Income.

Nuclear Fuel

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

Nuclear Decommissioning

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

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

We recorded a reserve for the costs expected to be incurred in the future to decommission Nine Mile Point under the discounted future cash flows methodology. The total reserve was $242.1 million at December 31, 2002 and $224.4 million at December 31, 2001. We determined that the decommissioning trust funds established for Nine Mile Point are adequately funded to cover the future costs to decommission the plant and as such, no contributions were made to the trust funds during the years ended December 31, 2002 and December 31, 2001.

In accordance with Nuclear Regulatory Commission (NRC) regulations, we maintain external decommissioning trusts to fund the costs expected to be incurred to decommission Calvert Cliffs and Nine Mile Point. The NRC requires utilities to provide financial assurance that they will accumulate sufficient funds to pay for the cost of nuclear decommissioning. The assets in the trusts are reported in "Nuclear decommissioning trust funds" in our Consolidated Balance Sheets.

We classify the investments in the nuclear decommissioning trust funds as available-for-sale securities, and we report these investments at fair value in our Consolidated Balance Sheets as previously discussed in this Note. Investments by nuclear decommissioning trust funds are guided by the "prudent man" investment principle. The funds are prohibited from investing in Constellation Energy or its affiliates and any other entity owning a nuclear power plant.

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

Capitalized Interest and Allowance for Funds Used During Construction

Capitalized Interest

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

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

Allowance for Funds Used During Construction (AFC)

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

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

Long-Term Debt

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

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

Accounting Standards Adopted

SFAS No. 148

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

Recently Issued Accounting Standards

SFAS No. 143

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

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

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

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

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

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

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

SFAS No. 146

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

FIN 45

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

FIN 46

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

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

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

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

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

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

We believe that the net amount we will add to our Consolidated Balance Sheets when we consolidate VIEs for which we are the primary beneficiary is approximately equal to our recorded investment and will not result in recording a cumulative effect of an accounting change upon initial adoption of FIN 46. The maximum exposure to loss represents the loss that we would incur if our investment in all of these entities were to become worthless and we were required to fund the full amount of all guarantees associated with these entities. Our maximum exposure to loss as of December 31, 2002 consists of the following:

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

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

EITF 02-3

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

- EITF 02-3 prohibits the use of mark-to-market accounting for any energy-related contracts that are not derivatives. Any contracts subject to EITF 02-3 must be accounted for on the accrual basis and recorded in the income statement gross rather than net upon application of EITF 02-3. This change applied immediately to new contracts executed after October 25, 2002 and applied to existing non-derivative energy-related contracts beginning January 1, 2003.
- We are required to report the impact of initially applying EITF 02-3 as the cumulative effect of a change in accounting principle effective January 1, 2003.
- The EITF minutes on Issue 02-3 indicate that an entity should not record unrealized gains or losses at the inception of derivative contracts unless the fair value of the contracts is evidenced by observable market data.

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

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

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

	Assets	Liabilities	Net
	(In millions)		
Mark-to-market energy contracts			
Current	$ 144.0	$ 94.1	$ 49.9
Noncurrent	1,348.2	881.5	466.7
Total	1,492.2	975.6	516.6
Other			
Current	85.7	56.8	28.9
Noncurrent	24.2	2.5	21.7
Total	109.9	59.3	50.6
Balance at December 31, 2002	1,602.1	1,034.9	567.2
Impact of EITF 02-3 Adoption			
Non-derivative net asset reversed as cumulative effect of a change in accounting principle			
Mark-to-market energy contracts	(494.7)	(119.8)	(374.9)
Other	(109.9)	(59.3)	(50.6)
Total non-derivative net asset reversed as cumulative effect of a change in accounting principle	(604.6)	(179.1)	(425.5)
Derivatives designated as hedges	(88.3)	(94.4)	6.1
Derivatives designated as normal purchases and sales	(192.6)	(128.3)	(64.3)
Mark-to-market derivatives remaining after adoption of EITF 02-3 on January 1, 2003	$ 716.6	$ 633.1	$ 83.5

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

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

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

2002 Events

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

Workforce Reduction Costs

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

Costs associated with 2001 Programs

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

- We recorded $52.9 million when 308 employees elected the age 50 to 54 Voluntary Special Early Retirement Program (VSERP).
- We reversed $17.8 million of the $25.1 million involuntary severance accrual that was recorded in 2001 to reflect the employees that elected the age 50 to 54 VSERP. Ultimately, we involuntarily severed 129 employees that resulted in a total cost for the involuntary severance program of $7.3 million.
- We recorded $29.6 million of settlement charges related to our pension plans under SFAS No. 88, *Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits*. These charges reflect the recognition of actuarial gains and losses associated with employees who have retired and taken their pension in the form of a lump-sum payment. Under SFAS No. 88, the settlement charge could not be recognized until lump-sum pension payments exceeded annual pension plan service and interest cost, which occurred in 2002.
- We recorded a $1.6 million expense associated with deferred payments to employees eligible for the VSERP.
- Partially offsetting these costs, we reversed approximately $2.6 million of previously accrued workforce reduction costs primarily as a result of the reversal of education and outplacement assistance benefits we accrued that employees did not utilize to the extent expected.

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

Costs associated with 2002 Programs

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

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

- We recorded $1.6 million of workforce reduction costs for the severance of 27 employees in our information technology organization. BGE recorded $0.6 million of this amount.
- We recorded $1.9 million of workforce reduction costs for the severance of 20 employees in our legal organization. BGE recorded $0.9 million of this amount.

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

Impairment Losses and Other Costs

Investments in Qualifying Facilities and Power Projects

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

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

- We recognized a $5.2 million other than temporary decline in value of our investment in a partnership that owns a geothermal project in Nevada. This project experienced a well implosion and we believe that the expected cash flows from the project will not be sufficient to recover our equity interest in that partnership.
- We recognized a $2.6 million other than temporary decline in value of our investment in a fuel processing site in Pennsylvania where the expected cash flows from a sublease are no longer expected to be sufficient to recover our lease costs associated with this site.
- We recognized a $6.6 million other than temporary decline in value of our investment in a partnership that owns a waste burning power project in Michigan. In 2001, we recognized a $6.1 million pre-tax impairment loss on this investment because we expected operating cash flows would not be sufficient to pay existing debt service and that we would not be able to recover our equity investment. However, at that time, we believed that we would recover our senior working capital loans receivable and accounts receivable for operating the project. As of the third quarter of 2002, the operating performance of the project did not improve as expected, and we believed the expected future cash flows were no longer sufficient to recover these receivables. Therefore, we recognized an additional impairment loss on this investment.

Closing of BGE Home Retail Merchandise Stores

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

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

Real Estate and International Investments

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

Net Gain on Sales of Investments and Other Assets

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

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

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

2001 Events

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

Workforce Reduction Costs

Voluntary Special Early Retirement Programs—VSERP

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

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

Settlement and Curtailment Charges

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

Involuntary Severance Accrual

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

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

Contract Termination Related Costs

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

We also announced the termination of our power business services agreement with Goldman Sachs. We paid Goldman Sachs a total of $355 million, representing $196.7 million to terminate the power business services agreement with our origination and risk management operation and $159 million previously recognized as a payable for services rendered under the agreement.

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

Impairment Losses and Other Costs

Cancellation of Domestic Power Projects

In the fourth quarter of 2001, our merchant energy business recorded impairments of $46.9 million primarily due to $40.8 million in impairments associated with the termination of our planned development projects in Texas, California, Florida, and Massachusetts not under construction. We decided to terminate our development projects due to the expected excess generation capacity in most domestic markets and the significant decline in the forward market prices of electricity. The impairments include amounts paid for the purchase of four turbines related to these development projects. In addition, we recognized $6.1 million for an other than temporary decline in the value of our investment in a waste burning power plant in Michigan where operating cash flows are not sufficient to pay existing debt service and we are not likely to recover our equity interest in this investment.

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

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

- We decided to sell six real estate projects without further development and all of our 18 senior-living facilities in 2002 and accelerate the exit strategies for two other real estate projects that we will continue to hold and own over the next several years. The real estate projects include approximately 1,300 acres of land holdings in various stages of development located in seven sites in the central Maryland region and an operating waste water treatment plant located in Anne Arundel County, Maryland. In 2002, we sold approximately 800 acres of land holdings.
- We decided to accelerate the exit strategy for our interest in a Panamanian electric distribution company. As a non-core asset, management has decided to reduce the cost and risk of holding this asset indefinitely and intends to dispose of this asset.
- We incurred an other than temporary decline in our equity-method investment in the Bolivian Generating Group, which owns an interest in an electric generation concession in Bolivia. This decline in value resulted from a deterioration of our investment's position in the dispatch curve of its capacity market. As a result, we recorded the impairment in accordance with the provisions of Accounting Principles Board Opinion No. 18.

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

Reduction of Financial Investment

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

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

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

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

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

In addition, we recognized $78.1 million pre-tax, or $47.2 million after-tax, gains including $15.7 million pre-tax, or $9.5 million after-tax, on the sale of two million shares of our Orion investment and $62.4 million pre-tax, or $37.7 million after-tax, on the sales of other financial investments.

3 Information by Operating Segment

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

- Our nonregulated merchant energy business in North America includes:
  - fossil, nuclear, and hydroelectric generating facilities and interests in qualifying facilities and power projects in the United States,
  - origination of structured transactions (such as load-serving, tolling contracts, and power purchase agreements), and risk management services (hedging of output from generating facilities and fuel costs),
  - electric and gas retail energy services to large commercial and industrial customers, and
  - generation and consulting services.
- Our regulated electric business purchases, transmits, distributes, and sells electricity in Maryland.
- Our regulated gas business purchases, transports, and sells natural gas in Maryland.

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

- Our remaining nonregulated businesses:
  - design, construct, and operate single-site heating, cooling, and cogeneration facilities for commercial and industrial customers,
  - service electric and gas appliances, and heating and air conditioning systems, engage in home improvements, and sell electricity and natural gas, and
  - own and operate a district cooling system for commercial customers.

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

These reportable segments are strategic businesses based principally upon regulations, products, and services that require different technology and marketing strategies. We evaluate the performance of these segments based on net income. We account for intersegment revenues using market prices. We present a summary of information by operating segment on the next page.

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

	Merchant Energy Business	Regulated Electric Business	Regulated Gas Business	Other Nonregulated Businesses	Unallocated Corporate Items and Eliminations	Consolidated
				(In millions)		
2002						
Unaffiliated revenues	$1,629.5	$1,965.6	$ 570.5	$ 537.4	$ —	$4,703.0
Intersegment revenues	1,136.2	0.4	10.8	—	(1,147.4)	—
Total revenues	2,765.7	1,966.0	581.3	537.4	(1,147.4)	4,703.0
Depreciation and amortization	242.8	174.2	47.4	16.6	—	481.0
Fixed charges	102.0	128.4	25.9	25.2	—	281.5
Income tax expense	127.2	67.1	22.4	92.9	—	309.6
Net income (a)	247.2	99.3	31.1	148.0	—	525.6
Segment assets	8,866.0	3,565.1	1,140.4	913.0	(355.6)	14,128.9
Capital expenditures	641.0	167.0	50.0	65.0	—	923.0
2001						
Unaffiliated revenues	$ 614.3	$2,039.6	$ 674.3	$ 550.6	$ —	$3,878.8
Intersegment revenues	1,151.2	0.4	6.4	2.0	(1,160.0)	—
Total revenues	1,765.5	2,040.0	680.7	552.6	(1,160.0)	3,878.8
Depreciation and amortization	174.9	173.3	47.7	23.2	—	419.1
Fixed charges	25.8	135.8	28.5	48.7	—	238.8
Income tax expense (benefit)	25.2	36.8	25.7	(49.8)	—	37.9
Cumulative effect of change in accounting principle	—	—	—	8.5	—	8.5
Net income (loss) (b)	93.1	50.9	37.5	(90.6)	—	90.9
Segment assets	8,123.9	3,764.9	1,104.2	1,314.0	(197.6)	14,109.4
Capital expenditures	1,044.0	180.3	58.7	35.0	—	1,318.0
2000						
Unaffiliated revenues	$ 421.1	$2,134.7	$ 603.8	$ 614.8	$ —	$3,774.4
Intersegment revenues	604.6	0.5	7.8	20.4	(633.3)	—
Total revenues	1,025.7	2,135.2	611.6	635.2	(633.3)	3,774.4
Depreciation and amortization	83.6	319.9	46.2	20.3	—	470.0
Equity in income of equity-method investees (c)	—	2.4	—	—	—	2.4
Fixed charges	18.3	168.4	27.3	65.8	(8.4)	271.4
Income tax expense	118.5	72.2	21.9	17.5	—	230.1
Net income (d)	198.6	102.3	30.6	13.8	—	345.3
Segment assets	7,295.5	3,392.3	1,089.9	1,491.5	(329.9)	12,939.3
Capital expenditures	699.0	290.3	59.7	131.5	—	1,180.5

(a) Our merchant energy business, our regulated electric business, our regulated gas business, and our other nonregulated businesses recognized after-tax charges (income) of $28.3 million, $20.5 million, $0.8 million, and ($161.1 million), respectively, for workforce reduction costs, business exit costs, impairment losses and other costs, and net gains on sales of investments and other assets as described in more detail in Note 2.

(b) Our merchant energy business, our regulated electric business, our regulated gas business, and our other nonregulated businesses recognized after-tax charges of $198.1 million, $33.6 million, $0.8 million, and $72.3 million, respectively, for workforce reduction costs, contract termination related costs, impairment losses and other costs, and a net gain on sales of investments and other assets as described more fully in Note 2.

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

(d) Our regulated electric business recorded an after-tax charge of $4.2 million related to employees that elected to participate in a Voluntary Special Early Retirement Program. In addition, our merchant energy business recorded a $15.0 million after-tax deregulation transition cost incurred by our origination and risk management operation. Our other nonregulated businesses also recorded a net gain of $47.2 million on sales of investments and other assets.

4 Investments

Real Estate Projects and Investments

Real estate projects and investments consist of the following:

At December 31,	2002	2001
	(In millions)	
Operating properties and properties under development	$77.8	$101.4
Equity interest in real estate investments	8.3	109.3
Total real estate projects and investments	$86.1	$210.7

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

See *Note 2* for a discussion of impairments recorded in 2002 and 2001.

Investments in Qualifying Facilities and Power Projects

Our merchant energy business holds up to a 50% ownership interest in 28 operating domestic energy projects that consist of electric generation, fuel processing, or fuel handling facilities. Of these 28 projects, 20 are "qualifying facilities" that receive certain exemptions and pricing under the Public Utility Regulatory Policy Act of 1978 based on the facilities' energy source or the use of a cogeneration process.

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

At December 31,	2002	2001
	(In millions)	
Geothermal	$151.4	$162.0
Coal	133.9	160.4
Hydroelectric	62.6	62.3
Biomass	52.6	59.4
Fuel Processing	23.2	33.6
Solar	10.5	10.7
Waste to Energy	—	2.6
Total	$434.2	$491.0

The investment in qualifying facilities and domestic power projects were accounted for under the following methods:

At December 31,	2002	2001
	(In millions)	
Equity Method	$423.7	$480.3
Cost Method	10.5	10.7
Total power projects	$434.2	$491.0

Our percentage voting interest in qualifying facilities and domestic power projects accounted for under the equity method ranges from 16% to 50%. Equity in earnings of these power projects were $9.1 million in 2002, $23.1 million in 2001, and $50.2 million in 2000.

Our power projects accounted for under the equity method include investments of $260.6 million in 2002 and $296.4 million in 2001 that sell electricity in California under power purchase agreements called "Interim Standard Offer No. 4" agreements. We discuss these projects further in *Note 11*.

Our other nonregulated businesses also held international energy projects accounted for under the equity method of $5.0 million at December 31, 2002 and $8.1 million at December 31, 2001.

See *Note 2* for a discussion of impairments recorded in 2002 and 2001.

Orion and Financial Investments

Financial investments consist of the following:

At December 31,	2002	2001
	(In millions)	
Orion	$ —	$442.5
Marketable equity securities	—	20.2
Financial limited partnerships	24.2	25.8
Leveraged leases	12.7	14.7
Total financial investments	$ 36.9	$503.2

We discuss the sale of our investment in Orion in *Note 2*.

Investments Classified as Available-for-Sale

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

- nuclear decommissioning trust funds,
- our other nonregulated businesses' marketable equity securities (shown above), and
- trust assets securing certain executive benefits.

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

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

At December 31, 2002	Amortized Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value
		(In millions)		
Marketable equity securities	$642.6	$18.9	$(69.2)	$592.3
Corporate debt and U.S. Government agency	51.5	1.7	(0.1)	53.1
State municipal bonds	22.0	1.3	—	23.3
Totals	$716.1	$21.9	$(69.3)	$668.7

At December 31, 2001	Amortized Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value
		(In millions)		
Marketable equity securities	$816.1	$270.6	$(10.3)	$1,076.4
Corporate debt and U.S. Government agency	47.7	1.5	—	49.2
State municipal bonds	38.4	3.3	(0.2)	41.5
Totals	$902.2	$275.4	$(10.5)	$1,167.1

In addition to the above securities, the nuclear decommissioning trust funds included $14.0 million at December 31, 2002 and $7.7 million at December 31, 2001 of cash and cash equivalents.

The preceding tables include $47.4 million in 2002 of net unrealized losses and $21.0 million in 2001 of net unrealized gains associated with the nuclear decommissioning trust funds that are reflected as a change in the nuclear decommissioning trust funds in our Consolidated Balance Sheets.

Gross and net realized gains and losses on available-for-sale securities, excluding the gains on our sales of the Orion investment, were as follows:

	2002	2001	2000
		(In millions)	
Gross realized gains	$ 6.0	$47.6	$54.5
Gross realized losses	(9.5)	(7.9)	(8.0)
Net realized (losses) gains	$(3.5)	$39.7	$46.5

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

At December 31, 2002	Amount
	(In millions)
Less than 1 year	$ 5.4
1-5 years	30.7
5-10 years	22.1
More than 10 years	18.2
Total maturities of debt securities	$76.4

5 Regulatory Assets (net)

As discussed in *Note 1*, the Maryland PSC and the FERC provide the final determination of the rates we charge our customers for our regulated businesses. Generally, we use the same accounting policies and practices used by nonregulated companies for financial reporting under accounting principles generally accepted in the United States of America. However, sometimes the Maryland PSC orders an accounting treatment different from that used by nonregulated companies to determine the rates we charge our customers. When this happens, we must defer certain utility expenses and income in our Consolidated Balance Sheets as regulatory assets and liabilities. We then record them in our Consolidated Statements of Income (using amortization) when we include them in the rates we charge our customers.

We summarize regulatory assets and liabilities in the following table, and we discuss each of them separately below.

At December 31,	2002	2001
	(In millions)	
Electric generation-related regulatory asset	$230.1	$249.0
Income taxes recoverable through future rates (net)	88.8	95.6
Deferred postretirement and postemployment benefit costs	32.3	35.5
Deferred environmental costs	23.2	26.0
Deferred fuel costs (net)	1.9	33.5
Workforce reduction costs	28.2	21.6
Other (net)	1.2	2.6
Total regulatory assets (net)	$405.7	$463.8

Electric Generation-Related Regulatory Asset

As a result of the deregulation of electric generation, BGE no longer met the requirements for the application of SFAS No. 71 for the electric generation portion of its business. In accordance with SFAS No. 101 and EITF 97-4, all individual generation-related regulatory assets and liabilities must be eliminated from our balance sheet unless these regulatory assets and liabilities will be recovered in the regulated portion of the business. BGE wrote-off all of its individual, generation-related regulatory assets and liabilities. BGE established a single, new generation-related regulatory asset for amounts to be collected through its regulated transmission and distribution business. The new regulatory asset is being amortized on a basis that approximates the pre-existing individual regulatory asset amortization schedules.

A portion of this regulatory asset represents the decommissioning and decontamination fund payment for federal uranium enrichment facilities that does not earn a return on the rate base investment. These amounts were $16.3 million at December 31, 2002 and $19.2 million at December 31, 2001. Prior to the deregulation of electric generation, these costs were recovered through the electric fuel rate mechanism, and were excluded from rate base. We will continue to amortize this amount through 2008.

Income Taxes Recoverable Through Future Rates (net)

As described in *Note 1*, income taxes recoverable through future rates are the portion of our net deferred income tax liability that is applicable to our regulated utility business, but has not been reflected in the rates we charge our customers. These income taxes represent the tax effect of temporary differences in depreciation and the allowance for equity funds used during construction, offset by differences in deferred tax rates and deferred taxes on deferred investment tax credits. We amortize these amounts as the temporary differences reverse.

Deferred Postretirement and Postemployment Benefit Costs

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

Deferred Environmental Costs

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

Deferred Fuel Costs

As described in *Note 1*, deferred fuel costs are the difference between our actual costs of natural gas and our fuel rate revenues collected from customers. We reduce deferred fuel costs as we collect them from or refund them to our customers.

In December 2002, a Hearing Examiner from the Maryland PSC issued a proposed order related to our annual gas adjustment clause review proceeding that will allow us to recover $1.7 million of a previously established regulatory asset of $9.4 million for certain credits that were over-refunded to customers through our market-based rates. BGE reserved the remaining difference of $7.7 million as disallowed fuel costs. However, we appealed the proposed order. As of the date of this report, the Maryland PSC has not acted on BGE's appeal.

Our gas deferred fuel costs were $1.9 million at December 31, 2002 and $33.5 million at December 31, 2001.

We exclude gas deferred fuel costs from rate base because their existence is relatively short-lived. These costs are recovered in the following year through the market-based rate mechanism.

Workforce Reduction Costs

The portions of the costs associated with the VSERP and workforce reduction programs we announced that relate to BGE's gas business are deferred as regulatory assets in accordance with the Maryland PSC's orders in prior rate cases. These costs are amortized over 5-year periods. See *Note 2* and *Note 6*.

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

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

Pension Benefits

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

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

We fund the plans by contributing at least the minimum amount required under Internal Revenue Service regulations. We calculate the amount of funding using an actuarial method called the projected unit credit cost method. The assets in all of the plans at December 31, 2002 were mostly marketable equity and fixed income securities.

Postretirement Benefits

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

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

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

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

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

For our regulated utility business, we accounted for the increase in annual postretirement benefit costs under two Maryland PSC rate orders:

- in an April 1993 rate order, the Maryland PSC allowed us to expense one-half and defer, as a regulatory asset (see *Note 5*), the other half of the increase in annual postretirement benefit costs related to our regulated electric and gas businesses, and
- in a November 1995 rate order, the Maryland PSC allowed us to expense all of the increase in annual postretirement benefit costs related to our regulated gas business.

Beginning in 1998, the Maryland PSC authorized us to:

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

Effective in 2002, we amended our postretirement medical plans for all affiliates other than Nine Mile Point. Our contributions for retiree medical coverage for future retirees that were under the age of 55 on January 1, 2002 are capped at the 2002 level. We also amended our plans to increase the Medicare eligible retirees' share of medical costs.

VSERP

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

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

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

The age 50 to 54 program allowed employees to make their elections beginning in 2002. The cost of that program was approximately $52.9 million ($43.0 million in pension termination costs, $8.5 million in postretirement benefit costs, and $1.4 million in education and outplacement assistance costs). Of this amount, BGE recorded approximately $13.4 million on its balance sheet as a regulatory asset of its gas business. We incurred approximately $0.7 million of postretirement benefit costs related to additional workforce reduction initiatives in 2002.

In connection with the retirement of a significant number of the participants in the nonqualified pension plans we recognized a settlement loss of approximately $10.5 million and a curtailment loss of approximately $5.8 million for those plans in accordance with SFAS No. 88 in 2001. We recorded additional settlement charges of $29.6 million related to our qualified and nonqualified pension plans in 2002 as a result of retirees electing to take their pension benefit in the form of a lump-sum payment.

At December 31, 2002, our pension obligations were greater than the fair value of our plan assets for our qualified and our nonqualified pension plans as follows:

	Qualified Plans		Non-Qualified	
	Nine Mile	Other	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

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

In 2002, we recorded an additional minimum pension liability of $189.5 million as a result of the decreases in the fair value of plan assets due to continued declines in the equity markets. We recorded $5.8 million of this adjustment as a reduction to an intangible asset. We included the remaining $195.3 million, or $118.1 million after-tax, of this adjustment in "Accumulated other comprehensive income."

The cost of the voluntary retirement programs and the settlement and curtailment losses are not included in the tables of net periodic pension and postretirement benefit costs for the respective years.

Obligations, Assets, and Funded Status

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

	Pension Benefits		Postretirement Benefits	
	2002	2001	2002	2001
	(In millions)			
Change in benefit obligation				
Benefit obligation at January 1	$1,259.2	$1,045.1	$ 475.2	$375.9
Service cost	29.6	25.8	5.0	8.4
Interest cost	82.2	76.1	26.7	29.2
Plan participants' contributions	—	—	4.7	3.0
Actuarial loss	78.9	42.6	34.9	49.1
Plan amendments	—	—	(110.3)	—
VSERP charge	43.0	63.5	9.2	18.5
Curtailment	—	9.7	—	—
Settlement	(37.9)	(23.0)	—	—
Nine Mile Point acquisition	—	91.8	—	15.0
Benefits paid	(207.5)	(72.4)	(30.0)	(23.9)
Benefit obligation at December 31	$1,247.5	$1,259.2	$ 415.4	$475.2

	Pension Benefits 2002	Pension Benefits 2001	Postretirement Benefits 2002	Postretirement Benefits 2001
	(In millions)			
Change in plan assets				
Fair value of plan assets at January 1	$ 912.2	$1,004.6	$ —	$ —
Actual return on plan assets	(89.4)	(42.7)	—	—
Employer contribution	152.4	22.7	25.3	20.9
Plan participants' contributions	—	—	4.7	3.0
Benefits paid	(207.5)	(72.4)	(30.0)	(23.9)
Fair value of plan assets at December 31	$ 767.7	$ 912.2	$ —	$ —

	Pension Benefits 2002	Pension Benefits 2001	Postretirement Benefits 2002	Postretirement Benefits 2001
	(In millions)			
Funded Status				
Funded Status at December 31	$(479.8)	$(347.0)	$(415.4)	$(475.2)
Unrecognized net actuarial loss	417.8	207.8	135.5	107.8
Unrecognized prior service cost	49.9	56.7	(43.8)	(0.4)
Unrecognized transition obligation	—	—	21.3	86.9
Pension liability adjustment	(322.5)	(133.0)	—	—
Accrued benefit cost	$(334.6)	$(215.5)	$(302.4)	$(280.9)

Net Periodic Benefit Cost

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

Year Ended December 31,	2002	2001	2000
	(In millions)		
Components of net periodic pension benefit cost			
Service cost	$ 29.6	$ 25.8	$ 25.4
Interest cost	82.2	76.1	73.1
Expected return on plan assets	(91.0)	(87.5)	(83.6)
Amortization of transition obligation	—	(0.2)	(0.2)
Amortization of prior service cost	6.7	6.5	6.5
Recognized net actuarial loss	1.3	2.8	2.6
Amount capitalized as construction cost	(2.9)	(2.5)	(3.4)
Net periodic pension benefit cost	$ 25.9	$ 21.0	$ 20.4

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

Year Ended December 31,	2002	2001	2000
	(In millions)		
Components of net periodic postretirement benefit cost			
Service cost	$ 5.0	$ 8.4	$ 7.7
Interest cost	26.7	29.2	26.6
Amortization of transition obligation	2.1	7.9	7.9
Recognized net actuarial loss	6.4	3.3	3.1
Amortization of unrecognized prior service cost	(3.5)	—	—
Amount capitalized as construction cost	(9.1)	(14.5)	(10.8)
Net periodic postretirement benefit cost	$27.6	$ 34.3	$34.5

Assumptions

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

At December 31,	Pension Benefits 2002	Pension Benefits 2001	Postretirement Benefits 2002	Postretirement Benefits 2001
Discount rate	6.75%	7.25%	6.75%	7.25%
Expected return on plan assets	9.00	9.00	N/A	N/A
Rate of compensation increase	4.00	4.00	4.00	4.00

We assumed the health care inflation rates to be:

- in 2002, 11.6% for Medicare-eligible retirees and 14.4% for retirees not covered by Medicare, and
- in 2003, 11.0% for both Medicare-eligible retirees and retirees not covered by Medicare.

After 2003, we assumed inflation rates will decrease to 8.0% in 2004, 6.0% in 2005, 5.5% from 2006 through 2008 and 5.0% annually after 2008.

A one-percent increase in the health care inflation rate from the assumed rates would increase the accumulated postretirement benefit obligation by approximately $34.3 million as of December 31, 2002 and would increase the combined service and interest costs of the postretirement benefit cost by approximately $2.6 million annually.

A one-percent decrease in the health care inflation rate from the assumed rates would decrease the accumulated postretirement benefit obligation by approximately $29.0 million as of December 31, 2002 and would decrease the combined service and interest costs of the postretirement benefit cost by approximately $2.2 million annually.

Other Postemployment Benefits

We provide the following postemployment benefits:

- health and life insurance benefits to eligible employees determined to be disabled under our Disability Insurance Plan,
- income replacement payments for Nine Mile Point union-represented employees determined to be disabled, and
- income replacement payments for other employees determined to be disabled before November 1995 (payments for employees determined to be disabled after that date are paid by an insurance company, and the cost is paid by employees).

The liability for these benefits totaled $49.7 million as of December 31, 2002 and $48.7 million as of December 31, 2001.

Effective December 31, 1993, we adopted SFAS No. 112, *Employers' Accounting for Postemployment Benefits*. We deferred, as a regulatory asset (see *Note 5*), the postemployment benefit liability attributable to our regulated utility business as of December 31, 1993, consistent with the Maryland PSC's orders for postretirement benefits (described earlier in this Note).

We began to amortize the regulatory asset over 15 years beginning in 1998. The Maryland PSC authorized us to reflect this change in our regulated electric and gas base rates to recover the higher costs in 1998.

We assumed the discount rate for other postemployment benefits to be 5.75% in 2002 and 5.0% in 2001.

Employee Savings Plan Benefits

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

- $13.3 million in 2002,
- $12.2 million in 2001, and
- $10.8 million in 2000.

7 Short-Term Borrowings

Our short-term borrowings may include bank loans, commercial paper, and bank lines of credit. Short-term borrowings mature within one year from the date of issuance. We pay commitment fees to banks for providing us lines of credit. When we borrow under the lines of credit, we pay market interest rates.

Constellation Energy

Constellation Energy had committed bank lines of credit under three credit facilities of $1.5 billion at December 31, 2002 for short-term financial needs as follows:

- $640 million 364-day revolving credit facility expiring in June 2003,
- $640 million three-year revolving credit facility expiring in June 2005, and
- $188.5 million revolving credit facility expiring in June 2003.

We use these facilities to allow issuance of commercial paper and letters of credit primarily for our merchant energy business. These facilities can issue letters of credit up to approximately $1.1 billion. Letters of credit issued under all of our facilities totaled $338.7 million at December 31, 2002 and $245.8 million at December 31, 2001. Constellation Energy had no commercial paper outstanding at December 31, 2002 and $954.9 million at December 31, 2001.

The weighted-average effective interest rates for Constellation Energy's commercial paper were 2.37% for the year ended December 31, 2002 and 3.73% for 2001.

BGE

BGE had no commercial paper outstanding at December 31, 2002 and 2001.

BGE maintains $200.0 million in annual committed credit facilities, expiring May through November of 2003, in order to allow commercial paper to be issued. At December 31, 2002, BGE had $200.0 million in unused credit facilities.

Other Nonregulated Businesses

Our other nonregulated businesses had short-term borrowings outstanding of $10.5 million at December 31, 2002 and $20.1 million at December 31, 2001. The weighted-average effective interest rates for our other nonregulated businesses' short-term borrowings were 3.61% at December 31, 2002 and 4.20% for 2001.

8 Long-Term Debt and Preference Stock

Long-term Debt

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

Constellation Energy

Constellation Energy issued the following fixed rate notes during 2002:

	Principal	Date Issued	Maturity and Repayment Date	Net Proceeds
		(In millions)		
6.35% Notes (interest payable semi-annually)	$ 600.0	3/02	4/07	$ 595.4
7.00% Notes (interest payable semi-annually)	600.0	3/02	4/12	592.9
7.60% Notes (interest payable semi-annually)	600.0	3/02	4/32	592.8
6.125% Notes (interest payable semi-annually)	500.0	8/02	9/09	496.1
7.00% Notes (interest payable semi-annually)	100.0	12/02	4/12	102.1
7.60% Notes (interest payable semi-annually)	100.0	12/02	4/32	99.6
Total	$2,500.0			$2,478.9

We used a portion of the net proceeds to repay short-term borrowings, to prepay the sellers' note of $388.1 million originally issued for the acquisition of Nine Mile Point Nuclear Station (Nine Mile Point), and to fund other acquisitions.

BGE

BGE's First Refunding Mortgage Bonds

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

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

- 6½% Series, due 2003
- 6⅛% Series, due 2003
- 5½% Series, due 2004
- 7½% Series, due 2007
- 6⅝% Series, due 2008

Holders of the Remarketed Floating Rate Series due September 1, 2006 have the option to require BGE to repurchase their bonds at face value on September 1 of each year. BGE is required to repurchase and retire at par any bonds that are not remarketed or purchased by the remarketing agent. BGE also has the option to redeem all or some of these bonds at face value each September 1.

On August 28, 2002, BGE called $11.8 million principal amount of its 7½% Series, due April 15, 2023 First Refunding Mortgage Bonds in connection with its annual sinking fund. Bonds called were redeemed at the price of 100% of principal, plus accrued interest from April 15, 2002 to August 28, 2002.

BGE's Other Long-Term Debt

On July 1, 2000, BGE transferred $278.0 million of tax-exempt debt to our merchant energy business related to the transferred assets. At December 31, 2002, BGE remains contingently liable for the $269.8 million outstanding balance of this debt.

On December 20, 2000, BGE issued $173.0 million of 6.75% Remarketable and Redeemable Securities (ROARS) due December 15, 2012. On December 15, 2002, BGE redeemed all the outstanding ROARS at 100% of the principal amount.

We show the weighted-average interest rates and maturity dates for BGE's fixed-rate medium-term notes outstanding at December 31, 2002 in the following table.

Series	Weighted-Average Interest Rate	Maturity Dates
B	8.62%	2006
C	7.97	2003
D	6.67	2004-2006
E	6.66	2006-2012
G	6.08	2008

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

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

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

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

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

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

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

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

Other Nonregulated Businesses
In November 2002, our other nonregulated businesses entered into a long-term bank facility of $51.7 million in principal with an interest rate of 3.25% fixed rate plus 3 months Eurodollar rate (interest payable quarterly), due December 2008 for net proceeds of $50.4 million.

Revolving Credit Agreement
ComfortLink had a $50 million unsecured revolving credit agreement that matured September 26, 2002. Under this agreement, ComfortLink had no amount outstanding at December 31, 2002 and $46.0 million outstanding at December 31, 2001.

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

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

Certain credit facilities of Constellation Energy contain a provision requiring Constellation Energy to maintain a ratio of debt to capitalization equal to or less than 65%. At December 31, 2002, the debt to capitalization ratios as defined in the credit agreements were no greater than 57%.

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

Failure by Constellation Energy, or BGE, to comply with these covenants could result in the maturity of the debt outstanding under these facilities being accelerated. The credit facilities of Constellation Energy contain usual and customary cross-default provisions that apply to defaults on debt by Constellation Energy and certain subsidiaries over a specified threshold. Certain BGE credit facilities also contain usual and customary cross-default provisions that apply to defaults on debt by BGE over a specified threshold. The indentures pursuant to which BGE has issued and outstanding mortgage bonds and subordinated debentures provide that a default under any debt instrument issued under the relevant indenture may cause a default of all debt outstanding under such indenture.

Constellation Energy also provides credit support to Calvert Cliffs and Nine Mile Point to ensure these plants have funds to meet expenses and obligations to safely operate and maintain the plants.

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

Year	Constellation Energy	Nonregulated Business	BGE
		(In millions)	
2003	$ —	$ 5.5	$ 284.2
2004	—	7.5	151.5
2005	300.0	8.1	43.2
2006	—	9.6	463.8
2007	600.0	10.5	127.6
Thereafter	1,900.0	308.6	829.7
Total long-term debt at December 31, 2002	$2,800.0	$349.8	$1,900.0

At December 31, 2002, we had long-term loans totaling $394.3 million that mature after 2002 which contain certain put options under which lenders could potentially require us to repay the debt prior to maturity. At December 31, 2002, $136.5 million is classified as current portion of long-term debt as a result of these provisions.

Weighted-Average Interest Rates for Variable Rate Debt

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

At December 31,	2002	2001
Nonregulated Businesses (including Constellation Energy)		
Floating rate notes	—%	4.95%
Loans under credit agreements	4.42	4.60
Mortgage and construction loans	—	4.39
Tax-exempt debt transferred from BGE	1.97	3.12
Other tax-exempt debt	1.49	1.75
BGE		
Remarketed floating rate series mortgage bonds	1.91%	4.49%
Floating rate reset notes	—	4.14

Preference Stock

Each series of BGE preference stock has no voting power, except for the following:

- the preference stock has one vote per share on any charter amendment which would create or authorize any shares of stock ranking prior to or on a parity with the preference stock as to either dividends or distribution of assets, or which would substantially adversely affect the contract rights, as expressly set forth in BGE's charter, of the preference stock, each of which requires the affirmative vote of two-thirds of all the shares of preference stock outstanding; and
- whenever BGE fails to pay full dividends on the preference stock and such failure continues for one year, the preference stock shall have one vote per share on all matters, until and unless such dividends shall have been paid in full. Upon liquidation, the holders of the preference stock of each series outstanding are entitled to receive the par amount of their shares and an amount equal to the unpaid accrued dividends.

9 Taxes

The components of income tax expense are as follows:

Year Ended December 31,	2002	2001	2000
	(Dollar amounts in millions)		
Income Taxes			
Current			
Federal	$ 145.0	$ 45.5	$148.2
State	24.2	27.0	48.2
Current taxes charged to expense	169.2	72.5	196.4
Deferred			
Federal	131.2	(22.4)	53.9
State	17.1	(4.1)	(11.8)
Deferred taxes charged to expense	148.3	(26.5)	42.1
Investment tax credit adjustments	(7.9)	(8.1)	(8.4)
Income taxes per Consolidated Statements of Income	$ 309.6	$ 37.9	$230.1

Total income taxes are different from the amount that would be computed by applying the statutory Federal income tax rate of 35% to book income before income taxes as follows:

Reconciliation of Income Taxes Computed at Statutory Federal Rate to Total Income Taxes			
Income before income taxes (excluding BGE preference stock dividends)	$ 848.4	$133.5	$588.6
Statutory federal income tax rate	35%	35%	35%
Income taxes computed at statutory federal rate	296.9	46.7	206.0
Increases (decreases) in income taxes due to			
Depreciation differences not normalized on regulated activities	4.8	5.6	12.6
Amortization of deferred investment tax credits	(7.9)	(8.1)	(8.4)
Synthetic fuel tax credits flowed through to income	(20.7)	(13.4)	(6.5)
State income taxes, net of federal income tax benefit	31.4	13.5	31.7
Other	5.1	(6.4)	(5.3)
Total income taxes	$ 309.6	$ 37.9	$230.1
Effective income tax rate	36.5%	28.4%	39.1%

The major components of our net deferred income tax liability are as follows:

At December 31,	2002	2001
	(Dollar amounts in millions)	
Deferred Income Taxes		
Deferred tax liabilities		
Net property, plant and equipment	$ 1,242.4	$1,156.0
Regulatory assets, net	110.7	130.2
Power marketing and risk management activities, net	285.5	227.3
Financial investments and hedging instruments	3.2	153.9
Other	130.3	147.9
Total deferred tax liabilities	1,772.1	1,815.3
Deferred tax assets		
Accrued pension and postemployment benefit costs	211.8	132.7
Deferred investment tax credits	30.0	35.1
Nuclear decommissioning liability	34.4	32.1
Reduction of investments	53.8	82.3
Other	111.4	102.1
Total deferred tax assets	441.4	384.3
Deferred tax liability, net	$ 1,330.7	$1,431.0

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

10 Leases

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

Outgoing Lease Payments

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

Lease expense was:

- $19.4 million in 2002,
- $11.7 million in 2001, and
- $11.3 million in 2000

At December 31, 2002, we owed future minimum payments for long-term, noncancelable, operating leases as follows:

Year	*(In millions)*
2003	$ 34.6
2004	50.8
2005	52.9
2006	21.7
2007	16.3
Thereafter	151.6
Total future minimum lease payments	$327.9

The above table includes the operating lease payments for the High Desert project in California through 2006. The project is scheduled for completion in mid-2003.

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

Accounting rules presently in effect for SPEs formed prior to February 2003, require that an SPE lessor must have sufficient independent equity at risk in order for us not to consolidate it. High Desert Power Trust maintains such a level of equity at risk, since the owners of the Trust maintain a minimum of 3% real equity at risk. In January 2003, the FASB issued Interpretation No. 46, *Consolidation of Variable Interest Entities,* which will require us to consolidate the Trust based on the current lease structure beginning July 1, 2003. We discuss this further in *Note 1*.

Under the terms of the lease, we are required to make payments that represent all or a portion of the lease balance if construction is terminated prior to completion or we default under the lease.

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

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

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

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

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

11 Commitments, Guarantees, and Contingencies

Commitments

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

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

Our merchant energy business has a long-term contract for the purchase of electric generating capacity and energy that expires in 2013. Portions of this contract became uneconomical upon the deregulation of electric generation. Therefore, we recorded a charge and accrued a corresponding liability based on the net present value of the excess of estimated contract costs over the market-based revenues to recover these costs over the remaining term of the contract. At December 31, 2002, the accrued portion of this contract was $9.2 million.

Our merchant energy business enters into various long-term contracts for the procurement and delivery of fuels to supply our generating plant requirements. In most cases, our contracts contain provisions for price escalations, minimum purchase levels, and other financial commitments. These contracts expire in various years between 2003 and 2013. In addition, our merchant energy business enters into long-term contracts for the capacity and transmission rights for the delivery of energy to meet our physical obligations to our customers. These contracts expire in various years between 2003 and 2013.

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

At December 31, 2002, we estimate the future obligations of our merchant energy business in the following table:

	2003	2004	2005	2006	2007	Thereafter	Total
				(In millions)			
Purchased capacity and energy	$182.8	$106.5	$ 54.2	$ 33.6	$12.9	$ 73.1	$ 463.1
Fuel and transportation	618.5	243.8	70.4	117.6	27.6	94.2	1,172.1
Capital and loans	32.7	0.5	—	—	—	—	33.2
Total future obligations	$834.0	$350.8	$124.6	$151.2	$40.5	$167.3	$1,668.4

Our regulated gas business entered into various long-term contracts that expire from 2004 to 2012 for the procurement, transportation, and storage of gas. These contracts are recoverable under BGE's gas cost adjustment clause discussed in *Note 1*.

BGE Home Products & Services has gas purchase commitments of $8.4 million in 2003 and $2.7 million in 2004 related to its gas program.

Long-Term Power Sales Contracts

We entered into long-term power sales contracts in connection with our load-serving activities. We also entered into long-term power sales contracts associated with certain of our power plants. Our load-serving power sales contracts extend for terms through 2009 and provide for the sale of full requirements energy to electricity distribution utilities and certain retail customers. Our power sales contracts associated with our power plants extend for terms into 2011 and provide for the sale of all or a portion of the actual output of certain of our power plants. All long-term contracts were executed at pricing that approximated market rates, including profit margin, at the time of execution.

Sale of Receivables

BGE Home Products & Services has an agreement to sell on an ongoing basis an undivided interest in a designated pool of customer receivables. Under the agreement, BGE Home Products & Services can sell up to a total of $50 million. Under the terms of the agreement, the buyer of the receivables has limited recourse against BGE Home Products & Services. BGE Home Products & Services recorded reserves for credit losses. At December 31, 2002, BGE Home Products & Services sold $47.7 million of receivables under the agreement.

Guarantees

The terms of our guarantees are as follows:

	Payments/Expiration				
	2003	2004-2005	2006-2007	Thereafter	Total
Competitive Supply	$1,758.8	$167.0	$ 35.8	$189.4	$2,151.0
Other	16.5	2.8	602.1	415.9	1,037.3
Total Guarantees	$1,775.3	$169.8	$637.9	$605.3	$3,188.3

At December 31, 2002, Constellation Energy had a total of $3,188.3 million guarantees outstanding related to loans, credit facilities, and contractual performance of certain of its subsidiaries as described below. These guarantees do not represent our incremental obligations and we do not expect to fund the full amount under these guarantees.

- Constellation Energy guaranteed $2,151.0 million on behalf of its subsidiaries for competitive supply activities. These guarantees are put into place in order to allow the subsidiaries flexibility needed to conduct business with counterparties without having to post substantial cash collateral. While the face amount of these guarantees is $2,151.0 million, we do not expect to fund the full amount as our calculated fair value of obligations covered by these guarantees was $519.8 million at December 31, 2002. The recorded fair value of obligations in our Consolidated Balance Sheets for these guarantees was $489.6 million at December 31, 2002.
- Constellation Energy guaranteed $104.5 million primarily on behalf of Nine Mile Point in connection with our acquisition in 2001.
- Constellation Energy guaranteed $56.6 million on behalf of our other nonregulated businesses primarily for loans and performance bonds of which $25.7 million was recorded in our Consolidated Balance Sheets at December 31, 2002.
- Constellation Energy guaranteed $600.0 million relating to the High Desert project as discussed in more detail in *Note 10*. This amount is included in the "Other" guarantees for 2006 in the table on the previous page.
- Our merchant energy business guaranteed $12.9 million for loans related to certain power projects in which we have an investment.
- BGE guaranteed two-thirds of certain debt of Safe Harbor Water Power Corporation, an unconsolidated investment. At December 31, 2002, Safe Harbor Water Power Corporation had outstanding debt of $20.0 million. The maximum amount of BGE's guarantee is $13.3 million. Additionally, BGE guaranteed the TOPrS of $250.0 million as discussed in *Note 8*.

The total fair value of the obligations for our guarantees recorded in our Consolidated Balance Sheets was $765.3 million and not the $3.2 billion of total guarantees. We assess the risk of loss from these guarantees to be minimal.

Environmental Matters

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

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

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

We discuss the significant matters below.

Clean Air Act

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

Certain of these provisions are described in more detail below.

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

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

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

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

In general, such standards can require the installation of additional air pollution control equipment upon the major modification of an existing plant. Although there have not been any new source review-related suits filed against our facilities, there can be no assurance that any of them will not be the target of an action in the future. Based on the levels of emissions control that the EPA and states are seeking in these new source review enforcement actions, we believe that material additional costs and penalties could be incurred, and planned capital expenditures could be accelerated, if the EPA was successful in any future actions regarding our facilities.

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

Future initiatives regarding greenhouse gas emissions and global warming continue to be the subject of much debate. The related Kyoto Protocol was signed by the United States but has since been rejected by the President, who instead has asked for an 18% decrease in carbon intensity on a voluntary basis. Future initiatives on this issue and the ultimate effects of the Kyoto Protocol and the President's initiatives on us are unknown at the date of this report. As a result of our diverse fuel portfolio, our contribution to greenhouse gases varies by plant type. Fossil fuel-fired power plants are significant sources of carbon dioxide emissions, a principal greenhouse gas. Our compliance costs with any mandated federal greenhouse gas reductions in the future could be material.

Clean Water Act

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

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

Waste Disposal

The EPA and several state agencies have notified us that we are considered a potentially responsible party with respect to the cleanup of certain environmentally contaminated sites owned and operated by others. We cannot estimate the cleanup costs for all of these sites.

However, based on a Record of Decision issued by the EPA in 1997, we can estimate that BGE's current 15.47% share of the reasonably possible cleanup costs at one of these sites, Metal Bank of America, a metal reclaimer in Philadelphia, could be as much as $1.3 million higher than amounts we believe are probable and have recorded as a liability in our Consolidated Balance Sheets. There has been no significant activity with respect to this site since the EPA's Record of Decision in 1997.

In late December 1996, BGE signed a consent order with the Maryland Department of the Environment that required it to implement remedial action plans for contamination at and around the Spring Gardens site, located in Baltimore, Maryland. The Spring Gardens site was once used to manufacture gas from coal and oil. BGE submitted the required remedial action plans and they were approved by the Maryland Department of the Environment. Based on these plans, the costs BGE considers to be probable to remedy the contamination are estimated to total $47 million. BGE recorded these costs as a liability on its Consolidated Balance Sheets and deferred these costs, net of accumulated amortization and amounts it recovered from insurance companies, as a regulatory asset. Because of the results of studies at this site, it is reasonably possible that additional costs could exceed the amount BGE recognized by approximately $14 million. Through December 31, 2002, BGE spent approximately $39 million for remediation at this site. BGE also investigated other small sites where gas was manufactured in the past. We do not expect the cleanup costs of the remaining smaller sites to have a material effect on our financial results.

Litigation

In the normal course of business, we are involved in various legal proceedings. We discuss the significant matters below.

California

Baldwin Associates, Inc. v. Gray Davis, Governor of California and 22 other defendants (including Constellation Power Development, Inc., a subsidiary of Constellation Power, Inc.)—This class action lawsuit was filed on October 5, 2001 in the Superior Court, County of San Francisco. The action seeks damages of $43 billion, recession and reformation of approximately 38 long-term power purchase contracts, and an injunction against improper spending by the state of California.

Constellation Power Development, Inc. is named as a defendant but does not have a power purchase agreement with the State of California. However, our High Desert Power Project does have a power purchase agreement with the California Department of Water Resources. In 2002, the court issued an order to the plaintiff asking that he show cause why he had not yet served the defendants. In April 2002, a second show cause order was issued. After several postponements, a hearing is now scheduled in March 2003 on that order.

NewEnergy

Constellation NewEnergy, Inc. v. PowerWeb Technology, Inc.—Prior to our acquisition, NewEnergy filed a complaint on May 9, 2002 in the U.S. District Court of Eastern Pennsylvania seeking approximately $100,000 in direct damages relating to a contract previously entered into with PowerWeb. PowerWeb Technology has counter-claimed seeking $100 million in damages against NewEnergy alleging a breach of a non-disclosure agreement by misappropriation of trade secrets. To date, discovery has just begun. We cannot predict the timing, or outcome, of the action or its possible effect on our financial results. However, based on the information available to Constellation Energy at this time, we believe NewEnergy has meritorious defenses to the PowerWeb Technology counterclaim.

Mercury Poisoning

Beginning in September 2002, BGE, Constellation Energy, and several other defendants have been involved in numerous actions alleging mercury poisoning from several sources, including coal plants formerly owned by BGE. The plants are now owned by a subsidiary of Constellation Energy. In addition to BGE and Constellation Energy, approximately 11 other defendants, consisting of pharmaceutical companies, manufacturers of vaccines and manufacturers of Thimerosal have been sued. Approximately 50 cases have been filed to date, with each case seeking $90 million in damages from the group of defendants. The claims were filed in the Circuit Court for Baltimore City, Maryland beginning in September 2002. The plaintiffs have filed motions to remand the cases back to the Baltimore City Circuit Court. At this time no discovery has occurred. We believe that we have meritorious defenses and intend to defend the action vigorously. However, we cannot predict the timing, or outcome, of these cases, or their possible effect on our, or BGE's, financial results.

Employment Discrimination

Miller, et. al v. Baltimore Gas and Electric Company, et al.—This action was filed on September 20, 2000 in the U.S. District Court for the District of Maryland. Besides BGE, Constellation Energy Group, Constellation Nuclear, and Calvert Cliffs Nuclear Power Plant are also named defendants. The action seeks class certification for approximately 150 past and present employees and alleges racial discrimination at Calvert Cliffs Nuclear Power Plant. The amount of damages is unspecified, however the plaintiffs seek back and front pay, along with compensatory and punitive damages. The Court scheduled a briefing process for the motion to certify the case as a class action suit. The briefing process is scheduled to end in July 2003. We do not believe class certification is appropriate and we further believe that we have meritorious defenses to the underlying claims and intend to defend the action vigorously. However, we cannot predict the timing, or outcome, of the action or its possible effect on our, or BGE's, financial results.

Asbestos

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

The first type is direct claims by individuals exposed to asbestos. BGE is involved in these claims with approximately 70 other defendants. Approximately 600 individuals that were never employees of BGE each claim $6 million in damages ($2 million compensatory and $4 million punitive). These claims were filed in the Circuit Court for Baltimore City, Maryland in the summer of 1993. BGE does not know the specific facts necessary to estimate its potential liability for these claims. The specific facts BGE does not know include:

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

To date, 67 of these cases were settled for amounts that were not significant. Approximately 300 cases are scheduled for trial in 2003.

The second type is claims by one manufacturer—Pittsburgh Corning Corp. (PCC)—against BGE and approximately eight others, as third-party defendants. On April 17, 2000, PCC declared bankruptcy.

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

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

Until the relevant facts for both types of claims are determined, we are unable to estimate what our, or BGE's, liability might be. Although insurance and hold harmless agreements from contractors who employed the plaintiffs may cover a portion of any awards in the actions, the potential effect on our, or BGE's, financial results could be material.

Other

McCray, et. al.v. Baltimore Gas and Electric Company—On June 10, 2002, a suit was filed in the Circuit Court of Baltimore City, Maryland seeking a total of $585 million in compensatory and punitive damages from BGE as a result of a fire in a home that caused five fatalities. Electricity to the home was shut off. BGE believes it has meritorious defenses and intends to defend the action vigorously. However, we cannot predict the timing, or outcome, of the action or its possible effect on our, or BGE's, financial results.

Storage of Spent Nuclear Fuel

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

Nuclear Insurance

We maintain nuclear insurance coverage for Calvert Cliffs and Nine Mile Point in four program areas: liability, worker radiation, property, and accidental outage. These policies contain certain industry standard exclusions, including, but not limited to, ordinary wear and tear, and war.

In November 2002, the President signed into law the Terrorism Risk Insurance Act ("TRIA") of 2002. Under the TRIA, property and casualty insurance companies are required to offer insurance for losses resulting from Certified acts of terrorism. Certified acts of terrorism are determined by the Secretary of State and Attorney General and primarily are based upon the occurrence of significant acts of international terrorism. Our nuclear property and accidental outage insurance programs, as discussed later in this section, provide coverage for Certified acts of terrorism.

Losses resulting from non-certified acts of terrorism are covered as a common occurrence, meaning that if non-certified terrorist acts occur against one or more commercial nuclear power plants insured by our insurance company within a 12-month period, they would be treated as one event and the owners of the plants would share one full limit of liability (currently $3.24 billion).

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

Nuclear Liability Insurance

Pursuant to the Price-Anderson Act, we are required to insure against public liability claims resulting from nuclear incidents to the full limit of public liability, approximately $9.6 billion. This limit of liability consists of the maximum available commercial insurance of $300 million and the remaining $9.3 billion is provided through mandatory participation in an industry-wide retrospective assessment program. Under this retrospective assessment program, we can be assessed up to $352.4 million per incident at any commercial reactor in the country, payable at no more than $40 million per incident per year. This assessment also applies in excess of our worker radiation claims insurance and is subject to inflation and state premium taxes. In addition, the U.S. Congress could impose additional revenue-raising measures to pay claims.

The Price-Anderson Act expired in August 2002. However, the Price-Anderson Act will remain in effect in its current form for existing reactors until it is renewed. A renewal bill was introduced in Congress in January 2003 to extend the Act for 15 years from August 1, 2002. The bill proposes a change in the annual retrospective premium limit from $10 million to $15 million per reactor per incident and a change in the maximum potential assessment from $88.1 million to $98.7 million per reactor per incident. If approved, these changes would increase the amount we could be assessed to $394.8 million per incident, payable at no more than $60 million per incident per year. We do not know what impact any other changes to the Act may have on us until a final resolution is reached.

Worker Radiation Claims Insurance

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

- Nuclear worker claims reported on or after January 1, 1998 are covered by a new insurance policy with an annual industry aggregate limit of $200 million for radiation injury claims against all those insured by this policy.
- All nuclear worker claims reported prior to January 1, 1998 are still covered by the old policy. Insureds under the old policies, with no current operations, are not required to purchase the new policy described above, and may still make claims against the old policies through 2007. If radiation injury claims under these old policies exceed the policy reserves, all policyholders could be retroactively assessed, with our share being up to $6.3 million.

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

Nuclear Property Insurance
Our policies provide $500 million in primary and an additional $2.25 billion in excess coverage for property damage, decontamination, and premature decommissioning liability for Calvert Cliffs or Nine Mile Point. This coverage currently is purchased through an industry mutual insurance company. If accidents at plants insured by the mutual insurance company cause a shortfall of funds, all policyholders could be assessed, with our share being up to $56.2 million.

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

Non-Nuclear Property Insurance
Our conventional property insurance provides coverage of $1.0 billion per occurrence for Certified acts of terrorism as defined under the TRIA.

Losses resulting from non-certified acts of terrorism are covered by an industry mutual insurance program. This program, which expires May 1, 2003, provides limits of $50 million per occurrence and is subject to a term aggregate limit of $100 million. These limits are shared among all companies participating in the program. The mutual insurer may renew this program depending upon the availability of reinsurance at the program's expiration. If terrorist acts at any of our facilities result in a loss exceeding this coverage, it could have a significant adverse impact on our financial results.

California Power Purchase Agreements
Our merchant energy business has $260.6 million invested in operating power projects of which our ownership percentage represents 137 megawatts of electricity that are sold to Pacific Gas & Electric (PGE) and to Southern California Edison (SCE) in California under power purchase agreements.

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

12 Hedging Activities and Fair Value of Financial Instruments

SFAS No. 133 Hedging Activities

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

Interest Rates

We use interest rate swaps to manage our interest rate exposures associated with new debt issuances. These swaps are designated as cash-flow hedges under SFAS No. 133 in anticipation of planned financing transactions as discussed in *Note 1*. The notional amounts of the contracts do not represent amounts that are exchanged by the parties and are not a measure of our exposure to market or credit risks. The notional amounts are used in the determination of the cash settlements under the contracts.

Prior to the March 2002 issuance of $1.8 billion of debt as discussed in *Note 8*, we entered into various forward starting interest rate swap contracts to manage our interest rate exposure related to this debt issuance. In 2001, we entered into swaps that had notional or contract amounts that totaled $800 million with an average rate of 4.9%. At December 31, 2001, the fair value of these swaps was an unrealized pre-tax gain of $36.3 million. In the first quarter of 2002, we entered into additional forward starting interest rate swaps with notional amounts that totaled $700 million with an average rate of 5.9%. All of these swap contracts expired at the end of March 2002 with a gain of $53.7 million.

In addition, we entered into forward starting interest rate swap contracts with notional amounts that totaled $400 million with an average rate of 5.1% to manage our interest rate exposure related to the issuance of $500 million of debt in 2002 as discussed in *Note 8*. These swap contracts expired in 2002 with a loss of $16.7 million.

We will reclassify the $37.0 million net gain from these swaps from "Accumulated other comprehensive income" into "Interest expense" and include them in earnings during the periods in which the hedged interest payments occur. We expect to reclassify $3.7 million of pre-tax net gains related to our expired swap contracts from "Accumulated other comprehensive income" into "Interest expense" in 2003.

Commodity Prices

Our origination and risk management operation uses a variety of derivative and non-derivative instruments to manage the commodity price risk of our competitive supply activities and our electric generation facilities, including power sales, fuel and energy purchases, emission credits, weather risk, and the market risk of outages. In order to manage these risks, we may enter into fixed-price derivative or non-derivative contracts to hedge the variability in future cash flows from forecasted sales of energy and purchases of fuel and energy, including:

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

The objectives for entering into such hedges include:

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

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

At December 31, 2002, our merchant energy business had designated certain fixed-price forward contracts as cash-flow hedges of forecasted sales of energy and forecasted purchases of fuel and energy for the years 2003 through 2010 under SFAS No. 133.

At December 31, 2002, our merchant energy business recorded net unrealized pre-tax losses of $45.3 million on these hedges, net of associated deferred income tax effects, in "Accumulated other comprehensive income." We expect to reclassify $24.7 million of net pre-tax gains on cash-flow hedges from "Accumulated other comprehensive income" into earnings during the next twelve months based on the market prices at December 31, 2002. However, the actual amount reclassified into earnings could vary from the amounts recorded at December 31, 2002 due to future changes in market prices. In 2002, we recognized $1.4 million of losses in earnings related to hedge ineffectiveness.

Fair Value of Financial Instruments

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

- cash and cash equivalents, net accounts receivable, other current assets, certain current liabilities, short-term borrowings, current portion of long-term debt, and certain deferred credits and other liabilities: because of their short-term nature, the amounts reported in our Consolidated Balance Sheets approximate fair value,
- investments and other assets where it was practicable to estimate fair value: the fair value is based on quoted market prices where available, and
- for long-term debt: the fair value is based on quoted market prices where available or by discounting remaining cash flows at current market rates.

We show the carrying amounts and fair values of financial instruments included in our Consolidated Balance Sheets in the following table, and we describe some of the items separately later in this Note.

At December 31,	2002		2001	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In millions)			
Investments and other assets for which it is:				
Practicable to estimate fair value	$ 755.1	$ 755.1	$1,183.6	$1,183.6
Not practicable to estimate fair value	24.2	N/A	25.8	N/A
Fixed-rate long-term debt	4,713.9	5,018.8	2,945.3	3,069.6
Variable-rate long-term debt	335.9	335.9	1,179.1	1,179.1

It was not practicable to estimate the fair value of investments held by our nonregulated businesses in several financial partnerships that invest in nonpublic debt and equity securities. This is because the timing and amount of cash flows from these investments are difficult to predict. We report these investments at their original cost in our Consolidated Balance Sheets.

The investments in financial partnerships totaled $24.2 million at December 31, 2002, representing ownership interests up to 10% and $25.8 million at December 31, 2001, representing ownership interests up to 11%. The total assets of all of these partnerships totaled $5.8 billion at December 31, 2001 (which is the latest information available).

13 Stock-Based Compensation

Under our long-term incentive plans, we granted stock options, performance and service-based restricted stock, and equity to officers, key employees, and members of the Board of Directors. Under the plans, we can grant up to a total of 18,000,000 shares. At December 31, 2002, we had stock options and restricted stock grants outstanding as discussed below.

Non-Qualified Stock Options

Options are granted at prices not less than the market value of the common stock at the date of grant, become vested over a period up to five years, and expire ten years from the date of grant. In accordance with APB No. 25, no compensation expense is recognized for these stock option awards.

In February 2002, our Committee on Management of the Board of Directors granted options, contingent on shareholder approval of our long-term incentive plan, with an exercise price equal to fair market value of our stock on the date of grant of $27.93. Our shareholders approved the plan at the annual meeting in May 2002 when then stock price had increased to $31.21. The difference between the exercise price and the fair market value in May when the shareholder approval contingency was satisfied was $6.3 million and is being amortized to compensation expense over a period up to five years. In 2002, we recorded compensation expense of $3.0 million related to this grant.

All other stock options grants have an exercise price equal to or greater than market value on the date of grant and were not subject to any future contingencies, therefore no compensation expense has been recognized. We reverse any expense associated with stock options that are canceled or forfeited prior to the vesting of the grants. Summarized information for our stock option grants is as follows:

	2002		2001		2000	
	Shares	Weighted-Average Exercise Price	Shares	Weighted-Average Exercise Price	Shares	Weighted-Average Exercise Price
	(In thousands, except per share amounts)					
Outstanding, beginning of year	2,646	$30.73	2,420	$ 34.65	—	$ —
Granted with Exercise Prices:						
At fair market value	1,708	30.62	1,015	25.08	·2,462	34.64
Less than fair market value on the date contingency was satisfied (1)	1,935	27.93	—	—	—	—
Greater than fair market value	103	31.21	—	—	—	—
Total granted	3,746	29.25	1,015	25.08	2,462	34.64
Exercised	—	—	(512)	(34.25)	—	—
Canceled/Expired	(311)	34.01	(277)	(37.74)	(42)	(34.25)
Outstanding, end of year	6,081	$29.65	2,646	$ 30.73	2,420	$ 34.65
Exercisable, end of year	1,413	$30.78	235	$ 34.25	—	—

Weighted-average fair value per share of options granted with Exercise Prices:	2002	2001	2000
At fair market value	$ 7.79	$ 9.27	$ 5.60
Less than fair market value on the date contingency was satisfied (1)	$ 9.15	—	—
Greater than fair market value	$ 5.89	—	—

(1) Shares were granted in February 2002 with an exercise price equal to fair market value of the stock on the grant date, and the grant was subject to shareholder approval of our long-term incentive plan. At the date of shareholder approval, the fair market value of the stock was higher than the grant date fair market value. Therefore, the difference is being amortized to compensation expense.

The following table summarizes information about stock options outstanding at December 31, 2002 (shares in thousands):

Range of Exercise Prices	Number Outstanding	Weighted-Average Remaining Contractual Life	Number Exercisable
$21.47—34.25	6,081	8.8 years	1,413

Restricted Stock Awards

In addition, we issue common stock based on meeting certain performance and/or service goals. This stock vests to participants at various times ranging from one to five years if the performance and/or service goals are met. In accordance with APB No. 25, we recognize compensation expense for our performance-based awards using the variable accounting method, whereby we amortize the value of the market price of the underlying stock on the date of grant adjusted for subsequent changes in fair market value through the lapse date to compensation expense over the performance period. We account for our service-based awards using the fixed accounting method, whereby we amortize the value of the market price of the underlying stock on the date of grant to compensation expense over the service period. We reverse any expense associated with restricted stock that is canceled or forfeited during the performance or service period.

We recorded compensation expense related to our restricted stock awards of $6.6 million in 2002 and $16.3 million in 2000. In 2001, due to non-attainment of performance criteria, we recorded a reduction to compensation expense of $10.1 million. Summarized share information for our restricted stock awards is as follows:

	2002	2001	2000
	(In thousands, except per share amounts)		
Outstanding, beginning of year	435	377	323
Granted	344	87	353
Released to participants	(170)	—	(277)
Canceled	(295)	(29)	(22)
Outstanding, end of year	314	435	377
Weighted-average fair value restricted stock granted	$27.23	$35.24	$32.89

Equity-Based Grants
In 2002, we recorded compensation expense of $0.5 million related to equity-based grants to members of the Board of Directors.

Pro-forma Information
Disclosure of pro-forma information regarding net income and earnings per share is required under SFAS No. 123, which uses the fair value method. The fair values of our stock-based awards were estimated as of the date of grant using the Black-Scholes option pricing model based on the following weighted-average assumptions:

	2002	2001	2000
Risk-free interest rate	4.45%	4.79%	6.73%
Expected life (in years)	5.0	5.0	10.0
Expected market price volatility factors	31.9%	41.3%	21.0%
Expected dividend yields	3.3%	1.8%	5.7%

We disclose the pro-forma effect on net income and earnings per share in accordance with SFAS No. 148, *Accounting for Stock-Based Compensation—Transition and Disclosure*, in *Note 1.*

14 Acquisitions

Acquisition of Alliance
On December 31, 2002, we purchased Alliance Energy Services, LLC and Fellon-McCord Associates, Inc. (collectively, Alliance) from Allegheny Energy, Inc. These businesses provide gas supply and transportation services and energy consulting services to large commercial and industrial customers primarily in the Midwest region, but also in other competitive energy markets including the Northeast, Mid-Atlantic, Texas and California regions. We acquired 100% ownership of these companies for a note payable of $21.2 million that was settled in cash on January 2, 2003. We acquired cash of $4.6 million as part of the purchase. We include these companies in our merchant energy business segment.

Our preliminary purchase price allocation for the net assets acquired is as follows:

At December 31, 2002	
	(In millions)
Cash	$ 4.6
Other Current Assets	89.1
Total Current Assets	93.7
Net Property, Plant and Equipment	0.6
Goodwill	10.0
Other Assets	3.7
Total Assets Acquired	108.0
Current Liabilities	84.5
Deferred Credits and Other Liabilities	2.3
Net Assets Acquired	$ 21.2

We recorded the existing contracts at fair value as part of the purchase price allocation. The preliminary net fair value of the contracts was $4.0 million. We recorded the fair value of these contracts as follows:

Net fair value of acquired contracts

	(In millions)
Current Assets	$20.8
Noncurrent Assets	3.7
Total Assets	24.5
Current Liabilities	18.2
Noncurrent Liabilities	2.3
Total Liabilities	20.5
Net fair value of acquired contracts	$ 4.0

We will amortize this value over a period extending through 2005. The weighted-average amortization period is approximately one year and represents the expected contract duration.

There are further refinements to the preliminary valuation of the existing contracts that have not been finalized that could impact our purchase price allocation.

On an unaudited pro-forma basis, had the acquisition of Alliance occurred on the first day of each of the years presented below, our nonregulated revenues and total revenues would have been as follows:

Year Ended December 31,	2002	2001	2000
	(In millions)		
Nonregulated revenues			
As reported	$2,166.9	$1,164.9	$1,035.9
Pro-forma	2,706.6	1,659.5	1,381.0
Total revenues			
As reported	$4,703.0	$3,878.8	$3,774.4
Pro-forma	5,242.7	4,373.4	4,119.5

We believe that the pro-forma impact on "Income before cumulative effect of change in accounting principle," "Net income," and "Earnings per common share" would not have been material had the acquisition of Alliance occurred on the first day of each of the years presented.

Acquisition of NewEnergy

On September 9, 2002, we purchased AES NewEnergy, Inc. from AES Corporation. Subsequent to the acquisition, we renamed AES NewEnergy, Inc. as Constellation NewEnergy, Inc. (NewEnergy). NewEnergy is a leading national provider of electricity, natural gas, and energy services, serving approximately 4,300 megawatts of load associated with large commercial and industrial customers in competitive energy markets including the Northeast, Mid-Atlantic, Midwest, Texas and California. We acquired 100% ownership of NewEnergy for cash of $250.3 million, including $1.4 million of direct costs associated with the acquisition. We acquired cash of $45.5 million as part of the purchase. We include NewEnergy in our merchant energy business segment.

Our preliminary purchase price allocation for the net assets acquired is as follows:

At September 9, 2002

	(In millions)
Cash	$ 45.5
Other Current Assets	376.5
Total Current Assets	422.0
Net Property, Plant and Equipment	7.0
Goodwill	105.0
Other Assets	46.9
Total Assets Acquired	580.9
Current Liabilities	276.3
Deferred Credits and Other Liabilities	54.3
Net Assets Acquired	$250.3

We recorded the existing contracts at fair value as part of the purchase price allocation. The preliminary net fair value of the contracts was $54.8 million. We recorded the fair value of these contracts as follows:

Net fair value of acquired contracts

	(In millions)
Current Assets	$ 78.6
Noncurrent Assets	45.0
Total Assets	123.6
Current Liabilities	46.8
Noncurrent Liabilities	22.0
Total Liabilities	68.8
Net fair value of acquired contracts	$ 54.8

We will amortize this value over a period extending through 2007. The weighted-average amortization period is approximately 2 years and represents the expected contract duration.

Currently, the following items have not been finalized that could impact our purchase price allocation:

- adjustments to the preliminary estimates of severance costs recorded as current liabilities associated with the integration of NewEnergy into our operations, and
- outcome of litigation matters.

On an unaudited pro-forma basis, had the acquisition of NewEnergy occurred on the first day of each of the years presented below, our nonregulated revenues and total revenues would have been as follows:

Year Ended December 31,	2002	2001	2000
		(In millions)	
Nonregulated revenues			
As reported	$2,166.9	$1,164.9	$1,035.9
Pro-forma	3,307.7	1,885.1	1,584.7
Total revenues			
As reported	$4,703.0	$3,878.8	$3,774.4
Pro-forma	5,843.8	4,599.0	4,323.2

We believe that the pro-forma impact on "Income before cumulative effect of change in accounting principle," "Net income," and "Earnings per common share" would not have been material had the acquisition of NewEnergy occurred on the first day of each of the years presented.

Acquisition of Nine Mile Point

On November 7, 2001, we completed our purchase of Nine Mile Point located in Scriba, New York. Nine Mile Point consists of two boiling-water reactors. Unit 1 is a 609-megawatt reactor that entered service in 1969. Unit 2 is a 1,148-megawatt reactor that began operation in 1988.

Nine Mile Point Nuclear Station, LLC, a subsidiary of Constellation Nuclear, purchased 100 percent of Nine Mile Point Unit 1 and 82 percent of Unit 2. Approximately one-half of the purchase price, or $380 million, in addition to settlement costs of $2.7 million, was paid at closing. The remainder was financed through the sellers in a note to be repaid over five years with an interest rate of 11.0%. This note was prepaid in April 2002. The sellers also transferred to us approximately $442 million in decommissioning funds. As a result of this purchase, we own 1,550 megawatts of Nine Mile Point's 1,757 megawatts of total generating capacity.

Niagara Mohawk Power Corporation was the sole owner of Nine Mile Point Unit 1. The co-owners of Unit 2 who sold their interests are: Niagara Mohawk (41 percent), New York State Electric and Gas (18 percent), Rochester Gas & Electric Corporation (14 percent), and Central Hudson Gas & Electric Corporation (9 percent). The Long Island Power Authority will continue to own 18 percent of Unit 2.

We will sell 90 percent of our share of Nine Mile Point's output back to the sellers at an average price of nearly $35 per megawatt-hour for approximately 10 years under power purchase agreements. The contracts for the output are on a unit contingent basis (if the output is not available because the plant is not operating, there is no requirement to provide output from other sources).

Nine Mile Point Net Assets Acquired

At November 7, 2001	
	(In millions)
Current Assets	$138.4
Nuclear Decommissioning Trust Fund	441.7
Net Property, Plant and Equipment	280.3
Intangible Assets (details below)	37.6
Total Assets Acquired	898.0
Current Liabilities	18.5
Deferred Credits and Other Liabilities	108.7
Net Assets Acquired	770.8
Note to Sellers	388.1
Total Cash Paid	$382.7

The intangible assets acquired consist of the following:

Description	Amount	Weighted-Average Useful Life
	(In millions)	*(In years)*
Operating procedures and manuals	$22.3	10
Permits and licenses	13.0	27
Software	2.3	5
Total intangible assets	$37.6	

15 Related Party Transactions—BGE

Income Statement
BGE is providing standard offer service to customers at fixed rates over various time periods during the transition period, July 1, 2000 to June 30, 2006, for those customers that do not choose an alternate supplier. Our origination and risk management operation is under contract to provide BGE with the energy and capacity required to meet its standard offer service obligations for the first three years of the transition period, and 90% of the energy and capacity for the final three years (July 1, 2003—June 30, 2006) of the transition period. The cost of BGE's purchased energy from nonregulated affiliates of Constellation Energy to meet its standard offer service obligation was $1,080.5 million for the year ended December 31, 2002, $1,150.1 million for the year ended December 31, 2001, and $581.0 million for the year ended December 31, 2000.

In addition, Constellation Energy charges BGE for the costs of certain corporate functions. Certain costs are directly assigned to BGE. We allocate other corporate function costs based on a total percentage of expected use by BGE. Management believes this method of allocation is reasonable and approximates the cost BGE would have incurred as an unaffiliated entity. These costs were $32.2 million for the year ended December 31, 2002, $27.1 million for the year ended December 31, 2001, and $21.6 million for the year ended December 31, 2000.

Balance Sheet
BGE participates in a cash pool under a Master Demand Note agreement with Constellation Energy. Under this arrangement, participating subsidiaries may invest in or borrow from the pool at market interest rates. Constellation Energy administers the pool and invests excess cash in short-term investments or issues commercial paper to manage consolidated cash requirements. Under this arrangement, BGE had invested $338.1 million at December 31, 2002 and $439.1 million at December 31, 2001.

Amounts related to corporate functions performed at the Constellation Energy holding company, BGE's purchases to meet its standard offer service obligation, and BGE's charges to Constellation Energy and its nonregulated affiliates for certain services it provides them result in intercompany balances on BGE's Consolidated Balance Sheets.

Management believes its allocation methods are reasonable and approximate the costs that would be charged to unaffiliated entities.

16 Quarterly Financial Data (Unaudited)

Our quarterly financial information has not been audited but, in management's opinion, includes all adjustments necessary for a fair presentation. Our utility business is seasonal in nature with the peak sales periods generally occurring during the summer and winter months. Accordingly, comparisons among quarters of a year may not represent overall trends and changes in operations.

2002 Quarterly Data—Constellation Energy

	Revenues	Income from Operations	Earnings Applicable to Common Stock	Earnings Per Share of Common Stock
	(In millions, except per-share amounts)			
Quarter Ended				
March 31	$1,040.0	$ 418.6	$228.6	$1.40
June 30	1,020.8	184.9	81.3	0.50
September 30	1,270.3	308.0	150.7	0.92
December 31	1,371.9	174.7	65.0	0.39
Year Ended				
December 31	$4,703.0	$1,086.2	$525.6	$3.20

2002 Quarterly Data—BGE

	Revenues	Income from Operations	Earnings Applicable to Common Stock
	(In millions)		
Quarter Ended			
March 31	$ 683.7	$113.0	$ 43.9
June 30	572.9	73.1	20.3
September 30	668.5	87.3	30.6
December 31	622.2	92.9	35.1
Year Ended			
December 31	$2,547.3	$366.3	$129.9

First quarter results include:
Constellation Energy and BGE
- workforce reduction costs totaling $15.6 million after-tax, of which BGE recorded $12.6 million.

Constellation Energy
- gain on the sale of investments, including Orion, of $164.2 million after-tax.

Second quarter results include:
Constellation Energy and BGE
- workforce reduction costs totaling $8.0 million after-tax, of which BGE recorded $4.8 million.

Constellation Energy
- gain on the sale of investments of $1.9 million after-tax, and
- loss on sale of turbine of $3.9 million after-tax.

Third quarter results include:
Constellation Energy and BGE
- workforce reduction costs totaling $7.5 million after-tax, of which BGE recorded $2.0 million.

Constellation Energy
- impairment of investments in qualifying facilities and domestic power projects, costs associated with exit of BGE Home merchandise stores, and impairment of real estate and international investments totaling $17.1 million after-tax.

Fourth quarter results include:
Constellation Energy and BGE
- workforce reduction costs totaling $6.9 million after-tax, of which BGE recorded $1.9 million.

Constellation Energy
- gains on the sale of investments of $4.5 million after-tax.

We discuss our special items in *Note 2.*

The sum of the quarterly earnings per share amounts may not equal the total for the year due to the effects of rounding and dilution as a result of issuing common shares during the year.

2001 Quarterly Data—Constellation Energy

	Revenues	Income from Operations	Earnings Applicable to Common Stock	Earnings Per Share of Common Stock
	(In millions, except per-share amounts)			
Quarter Ended				
March 31	$1,130.5	$235.0	$111.8	$0.74
June 30	826.1	171.0	75.6	0.46
September 30	1,043.4	317.5	163.6	1.00
December 31	878.8	(365.7)	(260.1)	(1.59)
Year Ended				
December 31	$3,878.8	$357.8	$ 90.9	$0.57

2001 Quarterly Data—BGE

	Revenues	Income from Operations	Earnings Applicable to Common Stock
	(In millions)		
Quarter Ended			
March 31	$ 849.9	$141.1	$ 55.1
June 30	607.1	74.7	19.9
September 30	701.4	80.4	23.8
December 31	562.3	15.6	(14.7)
Year Ended			
December 31	$2,720.7	$311.8	$ 84.1

First quarter results include:
Constellation Energy
- an $8.5 million after-tax gain for the cumulative effect of adopting SFAS No. 133, and
- a gain on sale of investments of $10.0 million after-tax.

Second quarter results include:
Constellation Energy
- a gain on sale of investments of $10.3 million after-tax.

Third quarter results include:
Constellation Energy
- a gain on sale of investments of $0.5 million after-tax.

Fourth quarter results include:
Constellation Energy and BGE
- workforce reduction costs totaling $64.1 million after-tax, of which BGE recorded $34.4 million after-tax.

Constellation Energy
- contract termination related costs, and impairment losses and other costs totaling an additional $242.6 million after-tax, and
- a net loss on sale of investments and other assets of $22.7 million after-tax.

We discuss our special items in *Note 2.*

The sum of the quarterly earnings per share amounts may not equal the total for the year due to the effects of rounding and dilution as a result of issuing common shares during the year.

Certain prior-year amounts have been reclassified to conform with the current year's presentation.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure
None.

PART III

BGE meets the conditions set forth in General Instruction I(1)(a)and (b) of Form 10-K for a reduced disclosure format. Accordingly, all items in this section related to BGE are not presented.

Item 10. Directors and Executive Officers of the Registrant
The information required by this item with respect to directors is set forth under *Election of Constellation Energy Directors* in the Proxy Statement and is incorporated herein by reference.

The information required by this item with respect to executive officers of Constellation Energy Group, pursuant to instruction 3 of paragraph (b) of Item 401 of Regulation S-K, is set forth in Item 4 of Part I of this Form 10-K under *Executive Officers of the Registrant.*

Item 11. Executive Compensation
The information required by this item is set forth under *Directors' Compensation, Compensation Committee Interlocks and Insider Participation, Executive Compensation, Common Stock Performance Graph* and *Report of Committee on Management on Executive Compensation* in the Proxy Statement and is incorporated herein by reference.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Shareholder Matters

Equity Compensation Plan Information

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants, and rights	(b) Weighted-average exercise price of outstanding options, warrants, and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in item (a)).
	(In thousands)		*(In thousands)*
Equity compensation plans approved by security holders	3,769	$29.60	6,437
Equity compensation plans not approved by security holders	2,312	$29.74	4,320
Total	6,081	$29.65	10,757

The plans that do not require security holder approval are the Constellation Energy Group, Inc. 2002 Senior Management Long-Term Incentive Plan (Designated as Exhibit No. 10(u)) and the Constellation Energy Group, Inc. Management Long-Term Incentive Plan (Designated as Exhibit No. 10(v)). Under these plans, we may grant up to a total of 7,000,000 equity shares. We have granted stock options and performance and service-based restricted stock to officers and key employees.

The additional information required by this item is set forth under *Security Ownership* in the Proxy Statement and is incorporated herein by reference.

Item 13. Certain Relationships and Related Transactions
The additional information required by this item is set forth under *Certain Relationships and Transactions* in the Proxy Statement and is incorporated herein by reference.

Item 14. Internal Controls and Procedures
Within the 90-day period prior to the filing of this report, an evaluation was carried out under the supervision and with the participation of management, including the principal executive officers and principal financial officer of both Constellation Energy and BGE, of the effectiveness of the design and operation of their disclosure controls and procedures (as defined in Rule 13a-14(c) under the Securities Exchange Act of 1934.) Based on that evaluation, such officers have concluded that the design and operation of Constellation Energy's and BGE's disclosure controls and procedures were effective.

No significant changes were made in either Constellation Energy's or BGE's internal controls or in other factors that could significantly affect such controls subsequent to the date of their evaluation.

PART IV
Item 15. Exhibits, Financial Statement Schedules and Reports on Form 8-K

(a) The following documents are filed as a part of this Report:

1. Financial Statements:

   Report of Independent Accountants dated January 29, 2003 of PricewaterhouseCoopers LLP
   Consolidated Statements of Income—Constellation Energy Group for three years ended December 31, 2002
   Consolidated Balance Sheets—Constellation Energy Group at December 31, 2002 and December 31, 2001
   Consolidated Statements of Cash Flows—Constellation Energy Group for three years ended December 31, 2002
   Consolidated Statements of Common Shareholders' Equity and Comprehensive Income—Constellation Energy Group for three years ended December 31, 2002
   Consolidated Statements of Capitalization—Constellation Energy Group at December 31, 2002 and December 31, 2001
   Consolidated Statements of Income—Baltimore Gas and Electric Company for three years ended December 31, 2002
   Consolidated Balance Sheets—Baltimore Gas and Electric Company at December 31, 2002 and December 31, 2001
   Consolidated Statements of Cash Flows—Baltimore Gas and Electric Company for three years ended December 31, 2002
   Notes to Consolidated Financial Statements

2. Financial Statement Schedules:
   Schedule II—Valuation and Qualifying Accounts
   Schedules other than Schedule II are omitted as not applicable or not required.

3. Exhibits Required by Item 601 of Regulation S-K.

Exhibit Number		
*2	—	Agreement and Plan of Share Exchange between Baltimore Gas and Electric Company and Constellation Energy Group, Inc. dated as of February 19, 1999. (Designated as Exhibit No. 2 in Form S-4 dated March 3, 1999, File No. 33-64799.)
*2(a)	—	Agreement and Plan of Reorganization and Corporate Separation (Nuclear). (Designated as Exhibit No. 2(a) in Form 8-K dated July 7, 2000, File Nos. 1-12869 and 1-1910.)
*2(b)	—	Agreement and Plan of Reorganization and Corporate Separation (Fossil). (Designated as Exhibit No. 2(b) in Form 8-K dated July 7, 2000, File Nos. 1-12869 and 1-1910.)
*3(a)	—	Articles of Amendment and Restatement of the Charter of Constellation Energy Group, Inc. as of April 30, 1999. (Designated as Exhibit No. 99.2 in Form 8-K dated April 30, 1999, File No. 1-1910.)
*3(b)	—	Articles Supplementary to the Charter of Constellation Energy Group, Inc., as of July 19, 1999. (Designated as Exhibit No. 3(a) in Form 10-Q dated August 13, 1999, File Nos. 1-12869 and 1-1910.)
*3(c)	—	Certificate of Correction to the Charter of Constellation Energy Group, Inc. as of September 13, 1999. (Designated as Exhibit No. 3(c) to the Annual Report on Form 10-K for the year ended December 31, 1999, File Nos. 1-12869 and 1-1910.)
*3(d)	—	Charter of BGE, restated as of August 16, 1996. (Designated as Exhibit No. 3 in Form 10-Q dated November 14, 1996, File No. 1-1910.)
*3(e)	—	Articles Supplementary to the Charter of Constellation Energy Group, Inc. as of November 20, 2001. (Designated as Exhibit No. 3(e) to the Annual Report on Form 10-K for the year ended December 31, 2001, File Nos. 1-12869 and 1-1910.)
3(f)	—	Bylaws of Constellation Energy Group, Inc., as amended to January 24, 2003.
*3(g)	—	Bylaws of BGE, as amended to October 16, 1998. (Designated as Exhibit No. 3 in Form 10-Q dated November 13, 1998, File No. 1-1910.)

*4(a) — Indenture between Constellation Energy Group, Inc. and the Bank of New York, Trustee dated as of March 24, 1999. (Designated as Exhibit No. 4(a) in Form S-3 dated March 29, 1999, File No. 333-75217.)

*4(b) — First Supplemental Indenture between Constellation Energy Group, Inc. and the Bank of New York, Trustee dated as of January 24, 2003. (Designated as Exhibit No. 4(b) in Form S-3 dated January 24, 2003, File No. 333-102723.)

*4(c) — Supplemental Indenture between BGE and Bankers Trust Company, as Trustee, dated as of June 20, 1995, supplementing, amending and restating Deed of Trust dated February 1, 1919. (Designated as Exhibit No. 4 in Form 10-Q dated August 11, 1995, File No. 1-1910); and the following Supplemental Indentures between BGE and Bankers Trust Company, Trustee:

Dated	File No.	Designated In	Exhibit Number
*January 15, 1992	33-45259	(Form S-3 Registration)	4(a)(ii)
*February 15, 1993	1-1910	(Form 10-K Annual Report for 1992)	4(a)(i)
*March 1, 1993	1-1910	(Form 10-K Annual Report for 1992)	4(a)(ii)
*March 15, 1993	1-1910	(Form 10-K Annual Report for 1992)	4(a)(iii)
*April 15, 1993	1-1910	(Form 10-Q dated May 13, 1993)	4
*July 1, 1993	1-1910	(Form 10-Q dated August 13, 1993)	4(a)
*October 15, 1993	1-1910	(Form 10-Q dated November 12, 1993)	4
*June 15, 1996	1-1910	(Form 10-Q dated August 13, 1996)	4

*4(d) — Indenture dated July 1, 1985, between BGE and The Bank of New York (Successor to Mercantile-Safe Deposit and Trust Company), Trustee. (Designated in Registration File No. 2-98443 as Exhibit 4(a)); as supplemented by Supplemental Indentures dated as of October 1, 1987 (Designated in Form 8-K, dated November 13, 1987, File No. 1-1910 as Exhibit 4(a)) and as of January 26, 1993 (Designated in Form 8-K, dated January 29, 1993, File No. 1-1910 as Exhibit 4(b).)

*4(e) — Form of Subordinated Indenture between the Company and The Bank of New York, as Trustee in connection with the issuance of the Junior Subordinated Debentures. (Designated as Exhibit 4(d) in Form S-3 dated May 28, 1998, File No. 333-53767.)

*4(f) — Form of Supplemental Indenture between the Company and The Bank of New York, as Trustee in connection with the issuances of the Junior Subordinated Debentures. (Designated as Exhibit 4(e) in Form S-3 dated May 28, 1998, File No. 333-53767.)

*4(g) — Form of Preferred Securities Guarantee (Designated as Exhibit 4(f) in Form S-3 dated May 28, 1998, File No. 333-53767.)

*4(h) — Form of Junior Subordinated Debenture (Designated as Exhibit 4(h) in Form S-3 dated May 28, 1998, File No. 333-53767.)

*4(i) — Form of Amended and Restated Declaration of Trust (including Form of Preferred Security) (Designated as Exhibit 4(c) in Form S-3 dated May 28, 1998, File No. 333-53767.)

*10(a) — Executive Annual Incentive Plan of Constellation Energy Group, Inc., as amended and restated. (Designated as Exhibit No. 10(a) to the Annual Report on Form 10-K for the year ended December 31, 2001, File Nos. 1-12869 and 1-1910.)

*10(b) — Constellation Energy Group, Inc. 1995 Long-Term Incentive Plan, as amended and restated. (Designated as Exhibit No. 10(b) to the Annual Report on Form 10-K for the year ended December 31, 2000, File Nos. 1-12869 and 1-1910.)

10(c) — Constellation Energy Group, Inc. Nonqualified Deferred Compensation Plan, as amended and restated.

*10(d) — Constellation Energy Group, Inc. Deferred Compensation Plan for Non-Employee Directors, as amended and restated. (Designated as Exhibit No. 10(d) to the Annual Report on Form 10-K for the year ended December 31, 2001, File Nos. 1-12869 and 1-1910.)

*10(e) — Baltimore Gas and Electric Company Retirement Plan for Non-Employee Directors, as amended and restated. (Designated as Exhibit No. 10(m) in Form 10-Q dated May 14, 1999, File Nos. 1-12869 and 1-1910.)

*10(f)	— Summary of severance arrangement for Edward A. Crooke. (Designated as Exhibit No. 10(g) to the Annual Report on Form 10-K for the year ended December 31, 1999, File Nos. 1-12869 and 1-1910.)
*10(g)	— Grantor Trust Agreement Dated as of January 1, 2001 between Constellation Energy Group, Inc. and Citibank, N.A. (Designated as Exhibit No. 10(g) to the Annual Report on Form 10-K for the year ended December 31, 2000, File Nos. 1-12869 and 1-1910.)
10(h)	— Form of Severance Agreements between Constellation Energy Group, Inc. and the following named executive officers: Mayo A. Shattuck III, E. Follin Smith, and Frank O. Heintz.
*10(i)	— Grantor Trust Agreement dated as of April 30, 1999 between Constellation Energy Group, Inc. and T. Rowe Price Trust Company. (Designated as Exhibit No. 10(e) in Form 10-Q dated May 14, 1999, File Nos. 1-12869 and 1-1910.)
*10(j)	— Full Requirements Service Agreement between Constellation Power Source, Inc. and Baltimore Gas and Electric Company. (Designated as Exhibit No. 10(a) in Form 10-Q dated August 14, 2000, File Nos. 1-12869 and 1-1910.) (Portions of this exhibit have been omitted pursuant to a request for confidential treatment.)
*10(k)	— Full Requirements Service Agreement between Constellation Power Source, Inc. and Baltimore Gas and Electric Company. (Designated as Exhibit No. 10(a) in Form 10-Q dated September 30, 2001, File Nos. 1-12869 and 1-1910.) (Portions of this exhibit have been omitted pursuant to a request for confidential treatment.)
*10(l)	— Full Requirements Service Agreement between Baltimore Gas and Electric Company and Allegheny Energy Supply Company, L.L.C. (Designated as Exhibit No. 10(b) in Form 10-Q dated September 30, 2001, File Nos. 1-12869 and 1-1910.) (Portions of this exhibit have been omitted pursuant to a request for confidential treatment.)
*10(m)	Constellation Energy Group, Inc. Benefits Restoration Plan, as amended and restated. (Designated as Exhibit No. 10(m) to the Annual Report on Form 10-K for the year ended December 31, 2001, File Nos. 1-12869 and 1-1910.)
*10(n)	— Constellation Energy Group, Inc. Supplemental Pension Plan, as amended and restated. (Designated as Exhibit No. 10(n) to the Annual Report on Form 10-K for the year ended December 31, 2001, File Nos. 1-12869 and 1-1910.)
*10(o)	— Constellation Energy Group, Inc. Senior Executive Supplemental Plan, as amended and restated. (Designated as Exhibit No. 10(o) to the Annual Report on Form 10-K for the year ended December 31, 2001, File Nos. 1-12869 and 1-1910.)
*10(p)	— Constellation Energy Group, Inc. Supplemental Benefits Plan, as amended and restated. (Designated as Exhibit No. 10(p) to the Annual Report on Form 10-K for the year ended December 31, 2001, File Nos. 1-12869 and 1-1910.)
10(q)	— Compensation agreements between Constellation Energy Group, Inc. and Michael J. Wallace (Attachment 1—Employment Agreement; Attachment 2—Severance Agreement.)
*10(r)	— Compensation agreements between Constellation Energy Group, Inc. and Thomas V. Brooks (Attachment 1—Offer letter; Attachment 2—Equity letter; Attachment 3—Retention plan summary.) (Designated as Exhibit No. 10(r) to the Annual Report on Form 10-K for the year ended December 31, 2001, File Nos. 1-12869 and 1-1910.)
10(s)	— Constellation Energy Group, Inc. Executive Long-Term Incentive Plan.
*10(t)	— Constellation Energy Group, Inc. 2002 Executive Annual Incentive Plan. (Designated as Exhibit No. II in the Definitive Proxy Statement on Schedule 14A filed on April 18, 2002.)
10(u)	— Constellation Energy Group, Inc. 2002 Senior Management Long-Term Incentive Plan.
10(v)	— Constellation Energy Group, Inc. Management Long-Term Incentive Plan.
10(w)	— Compensation agreements between Constellation Energy Group, Inc. and E. Follin Smith (Attachment 1. Offer letter; Attachment 2—Severance agreement.)
12(a)	— Constellation Energy Group, Inc. and Subsidiaries Computation of Ratio of Earnings to Fixed Charges.

12(b) — Baltimore Gas and Electric Company and Subsidiaries Computation of Ratio of Earnings to Fixed Charges and Computation of Ratio of Earnings to Combined Fixed Charges and Preferred and Preference Dividend Requirements.

21 — Subsidiaries of the Registrant.

23 — Consent of PricewaterhouseCoopers LLP, Independent Accountants.

* Incorporated by Reference.

(b) Reports on Form 8-K:
None.

CONSTELLATION ENERGY GROUP, INC. AND SUBSIDIARIES
AND
BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARIES
SCHEDULE II—VALUATION AND QUALIFYING ACCOUNTS

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at beginning of period	Charged to costs and expenses	Charged to Other Accounts— Describe	(Deductions)— Describe	Balance at end of period
			(In millions)		
Reserves deducted in the Balance Sheet from the assets to which they apply:					
Constellation Energy					
Accumulated Provision for Uncollectibles					
2002	$ 22.8	$26.4	$ 12.5 (A)	$ (19.8)(B)	$ 41.9
2001	21.3	26.5	—	(25.0)(B)	22.8
2000	34.8	21.1	—	(34.6)(B)	21.3
Valuation Allowance—					
Net unrealized (gain) loss on available for sale securities					
2002	(243.7)	—	243.7 (C)	—	—
2001	(33.7)	—	(210.0)(C)	—	(243.7)
2000	0.2	—	(33.9)(C)	—	(33.7)
Net unrealized (gain) loss on nuclear decommissioning trust funds					
2002	(21.0)	—	(26.4)(C)	—	(47.4)
2001	(34.7)	—	13.7 (C)	—	(21.0)
2000	(40.5)	—	5.8 (C)	—	(34.7)
Mark-to-market energy assets reserves					
2002	(43.4)	—	(6.5)(D)	—	(49.9)
2001	(54.4)	—	11.0 (D)	—	(43.4)
2000	(27.5)	—	(26.9)(D)	—	(54.4)
BGE					
Accumulated Provision for Uncollectibles					
2002	13.4	14.5	—	(16.4)(B)	11.5
2001	13.4	21.8	—	(21.8)(B)	13.4
2000	13.0	16.4	—	(16.0)(B)	13.4
Net unrealized (gain) loss on nuclear decommissioning trust fund					
2002	—	—	—	—	—
2001	—	—	—	—	—
2000	(40.5)	—	(1.8)(E)	42.3 (C)	—

(A) Represents amounts acquired resulting from our acquisitions of NewEnergy and Alliance.
(B) Represents principally net amounts charged off as uncollectible.
(C) Represents amounts recorded in or reclassified from accumulated other comprehensive income.
(D) Represents reserves from mark-to-market energy assets credited/(charged) to revenues.
(E) Represents net unrealized gains credited to accumulated depreciation.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, Constellation Energy Group, Inc., the Registrant, has duly caused this Report to be signed on its behalf by the undersigned, thereunto duly authorized.

CONSTELLATION ENERGY GROUP, INC.
(Registrant)

Date: March 7, 2003

By /s/ MAYO A. SHATTUCK III

Mayo A. Shattuck III
Chairman of the Board, Chief Executive Officer and President

Pursuant to the requirements of the Securities Exchange Act of 1934, this Report has been signed below by the following persons on behalf of Constellation Energy Group, Inc., the Registrant, and in the capacities and on the dates indicated.

Signature	Title	Date
Principal executive officer and director:		
By /s/ M. A. Shattuck III **M. A. Shattuck III**	Chairman of the Board, Chief Executive Officer, President and Director	March 7, 2003
Principal financial and accounting officer:		
By /s/ E. F. Smith **E. F. Smith**	Senior Vice President and Chief Financial Officer	March 7, 2003
Directors:		
/s/ D. L. Becker **D. L. Becker**	Director	March 7, 2003
/s/ J. T. Brady **J. T. Brady**	Director	March 7, 2003
/s/ F. P. Bramble, Sr. **F. P. Bramble, Sr.**	Director	March 7, 2003
/s/ B. B. Byron **B. B. Byron**	Director	March 7, 2003
/s/ E. A. Crooke **E. A. Crooke**	Director	March 7, 2003
/s/ J. R. Curtiss **J. R. Curtiss**	Director	March 7, 2003

Signature		Title	Date
/s/	R. W. Gale **R. W. Gale**	Director	March 7, 2003
/s/	F. A. Hrabowski, III **F. A. Hrabowski, III**	Director	March 7, 2003
/s/	E. J. Kelly, III **E. J. Kelly, III**	Director	March 7, 2003
/s/	N. Lampton **N. Lampton**	Director	March 7, 2003
/s/	R. J. Lawless **R. J. Lawless**	Director	March 7, 2003
/s/	M. D. Sullivan **M. D. Sullivan**	Director	March 7, 2003

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, Baltimore Gas and Electric Company, the Registrant, has duly caused this Report to be signed on its behalf by the undersigned, thereunto duly authorized.

BALTIMORE GAS AND ELECTRIC COMPANY
(Registrant)

Date: March 7, 2003

By */s/* FRANK O. HEINTZ

Frank O. Heintz
President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this Report has been signed below by the following persons on behalf of Baltimore Gas and Electric Company, the Registrant, and in the capacities and on the dates indicated.

Signature	Title	Date
Principal executive officer and director:		
By */s/* F. O. Heintz **F. O. Heintz**	President, Chief Executive Officer, and Director	March 7, 2003
Principal financial and accounting officer and director:		
By */s/* E. F. Smith **E. F. Smith**	Senior Vice President, Chief Financial Officer, and Director	March 7, 2003
Directors:		
/s/ M. A. Shattuck III **M. A. Shattuck III**	Director	March 7, 2003

Certification

I, Mayo A. Shattuck III, certify that:

1. I have reviewed this annual report on Form 10-K of Constellation Energy Group, Inc.;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:

a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

March 7, 2003

/s/ MAYO A. SHATTUCK III

Mayo A. Shattuck III,
Chairman of the Board, Chief Executive Officer and President

Certification

I, E. Follin Smith, certify that:

1. I have reviewed this annual report on Form 10-K of Constellation Energy Group, Inc.;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:

a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

March 7, 2003

/s/ E. FOLLIN SMITH

E. Follin Smith,
Senior Vice President and Chief Financial Officer

Certification

I, Frank O. Heintz, certify that:

1. I have reviewed this annual report on Form 10-K of Baltimore Gas and Electric Company;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:

a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

March 7, 2003

/s/ FRANK O. HEINTZ

Frank O. Heintz,
President and Chief Executive Officer

Certification

I, E. Follin Smith, certify that:

1. I have reviewed this annual report on Form 10-K of Baltimore Gas and Electric Company;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:

a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

March 7, 2003

/s/ E. FOLLIN SMITH

E. Follin Smith,
Senior Vice President and Chief Financial Officer