CONSTELLATION ENERGY GROUP INC
Form 10-Q
May 07, 2004

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For The Quarterly Period Ended **March 31, 2004**

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

MARYLAND
(State of Incorporation of both registrants)

750 E. PRATT STREET, BALTIMORE, MARYLAND 21202
(Address of principal executive offices) (Zip Code)

410-783-2800

(Registrants' telephone number, including area code)

NOT APPLICABLE

(Former name, former address and former fiscal year, if changed since last report)

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

Indicate by check mark whether Constellation Energy Group, Inc. is an accelerated filer Yes ý No o

Indicate by check mark whether Baltimore Gas and Electric Company is an accelerated filer Yes o No ý

COMMON STOCK, WITHOUT PAR VALUE 168,490,454 SHARES OUTSTANDING OF CONSTELLATION ENERGY GROUP, INC. ON APRIL 30, 2004.

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

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PART 1 FINANCIAL INFORMATION

Item 1 Financial Statements

CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

Constellation Energy Group, Inc. and Subsidiaries

Three Months Ended March 31,

	2004	2003
	(In millions, except per share amounts)	
Revenues		
Nonregulated revenues	**$ 2,234.3**	$ 1,545.5
Regulated electric revenues	**484.4**	486.3
Regulated gas revenues	**317.9**	298.2
Total revenues	**3,036.6**	2,330.0
Expenses		
Operating expenses	**2,600.7**	1,978.0
Depreciation and amortization	**123.0**	111.1
Accretion of asset retirement obligations	**11.2**	10.7
Taxes other than income taxes	**67.5**	68.3
Total expenses	**2,802.4**	2,168.1
Net Gain on Sales of Investments and Other Assets	**1.5**	13.7
Income from Operations	**235.7**	175.6
Other Income	**4.8**	8.9
Fixed Charges		
Interest expense	**84.8**	82.3
Interest capitalized and allowance for borrowed funds used during construction	**(2.6)**	(4.4)
BGE preference stock dividends	**3.3**	3.3
Total fixed charges	**85.5**	81.2
Income from Continuing Operations Before Income Taxes	**155.0**	103.3
Income Taxes	**42.5**	36.3
	112.5	67.0

Three Months Ended March 31,

	2004	2003
Income from Continuing Operations and Before Cumulative Effects of Changes in Accounting Principles		
Loss from Discontinued Operations, Net of Income Taxes of $23.8	**(46.3)**	
Cumulative Effects of Changes in Accounting Principles, Net of Income Taxes of $119.5		(198.4)
Net Income (Loss)	**$ 66.2**	$ (131.4)
Earnings (Loss) Applicable to Common Stock	**$ 66.2**	$ (131.4)
Average Shares of Common Stock Outstanding Basic	**168.1**	164.9
Average Shares of Common Stock Outstanding Diluted	**169.2**	164.9
Earnings Per Common Share and Earnings Per Common Share Assuming Dilution from Continuing Operations and Before Cumulative Effects of Changes in Accounting Principles	**$ 0.66**	$ 0.40
Loss from Discontinued Operations	**(0.27)**	
Cumulative Effects of Changes in Accounting Principles		(1.20)
Earnings (Loss) Per Common Share and Earnings (Loss) Per Common Share Assuming Dilution	**$ 0.39**	$ (0.80)
Dividends Declared Per Common Share	**$ 0.285**	$ 0.260

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

Constellation Energy Group, Inc. and Subsidiaries

Three Months Ended March 31,

	2004	2003
	(In millions)	
Net Income (Loss)	**$ 66.2**	$ (131.4)
Other comprehensive income (OCI)		
Reclassification of net gain on sales of securities from OCI to net income, net of taxes	**(0.3)**	(2.6)
Reclassification of net gain on hedging instruments from OCI to net income, net of taxes	**(24.8)**	(6.0)
Net unrealized gain (loss) on hedging instruments, net of taxes	**96.3**	(6.0)
Net unrealized gain (loss) on securities, net of taxes	**26.9**	(11.7)
Comprehensive Income (Loss)	**$ 164.3**	$ (157.7)

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

CONSOLIDATED BALANCE SHEETS

Constellation Energy Group, Inc. and Subsidiaries

	March 31,* 2004	***December 31,* 2003**
	(In millions)	
Assets		
Current Assets		
Cash and cash equivalents	**$ 840.8**	$ 721.3
Accounts receivable (net of allowance for uncollectibles of **$53.5** and $51.7, respectively)	**1,441.1**	1,563.0
Mark-to-market energy assets	**569.5**	488.3
Risk management assets	**577.7**	249.5
Materials and supplies	**202.9**	211.7
Fuel stocks	**108.9**	178.2
Assets held for sale discontinued operations	**87.6**	
Acquired contracts, net of amortization	**50.9**	67.0
Other	**177.8**	154.4
Total current assets	**4,057.2**	3,633.4
Investments and Other Assets		
Nuclear decommissioning trust funds	**792.5**	736.1
Investments in qualifying facilities and power projects	**328.1**	332.6
Mark-to-market energy assets	**343.5**	261.9
Risk management assets	**251.6**	158.4
Goodwill	**144.1**	144.0
Acquired contracts, net of amortization	**98.8**	105.8
Other	**238.1**	238.0
Total investments and other assets	**2,196.7**	1,976.8
Property, Plant and Equipment		
Regulated property, plant and equipment	**5,285.8**	5,266.7
Nonregulated generation property, plant and equipment	**7,614.9**	7,769.1
Other nonregulated property, plant and equipment	**404.2**	340.9
Nuclear fuel (net of amortization)	**229.6**	202.9
Accumulated depreciation	**(4,001.4)**	(3,978.1)
Net property, plant and equipment	**9,533.1**	9,601.5
Deferred Charges		
Regulatory assets (net)	**211.1**	229.5
Other	**138.2**	149.6

	March 31, **2004***	*December 31,* **2003**
Total deferred charges	**349.3**	379.1
Total Assets	**$ 16,136.3**	$ 15,590.8

** Unaudited*

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

CONSOLIDATED BALANCE SHEETS

Constellation Energy Group, Inc. and Subsidiaries

	March 31, **2004***	*December 31,* **2003**
	(In millions)	
Liabilities and Equity		
Current Liabilities		
Short-term borrowings	**$ 7.5**	$ 9.6
Current portion of long-term debt	**362.9**	343.2
Accounts payable	**1,051.1**	1,167.7
Customer deposits and collateral	**235.9**	181.7
Mark-to-market energy liabilities	**544.3**	474.6
Risk management liabilities	**193.9**	134.6
Liabilities associated with assets held for sale	**47.5**	
Other	**442.7**	523.6
Total current liabilities	**2,885.8**	2,835.0
Deferred Credits and Other Liabilities		
Deferred income taxes	**1,466.4**	1,384.4
Mark-to-market energy liabilities	**355.1**	258.0
Risk management liabilities	**404.0**	170.1
Asset retirement obligations	**605.1**	595.9
Postretirement and postemployment benefits	**364.2**	361.8
Net pension liability	**185.6**	225.7
Deferred investment tax credits	**76.6**	78.4
Other	**197.5**	198.4
Total deferred credits and other liabilities	**3,654.5**	3,272.7
Long-term Debt		
Long-term debt of Constellation Energy	**3,350.0**	3,350.0
Long-term debt of nonregulated businesses	**384.9**	389.2
First refunding mortgage bonds of BGE	**476.1**	476.1
Other long-term debt of BGE	**919.6**	919.6
6.20% deferrable interest subordinated debentures due October 15, 2043 to BGE wholly owned BGE Capital Trust II relating to trust preferred securities	**257.7**	257.7
Unamortized discount and premium	**(12.8)**	(10.2)
Current portion of long-term debt	**(362.9)**	(343.2)
Total long-term debt	**5,012.6**	5,039.2
Minority Interests	**115.7**	113.4
BGE Preference Stock Not Subject to Mandatory Redemption	**190.0**	190.0

	March 31, 2004*	December 31, 2003
Common Shareholders' Equity		
Common stock	**2,200.6**	2,179.8
Retained earnings	**2,100.2**	2,081.9
Accumulated other comprehensive loss	**(23.1)**	(121.2)
Total common shareholders' equity	**4,277.7**	4,140.5
Commitments, Guarantees, and Contingencies (see Notes)		
Total Liabilities and Equity	**$ 16,136.3**	$ 15,590.8

** Unaudited*

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

CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

Constellation Energy Group, Inc. and Subsidiaries

Three Months Ended March 31,	**2004**	**2003**
	(In millions)	
Cash Flows From Operating Activities		
Net income (loss)	**$ 66.2**	$ (131.4)
Adjustments to reconcile to net cash provided by operating activities		
Loss from discontinued operations	**46.3**	
Cumulative effects of changes in accounting principles		198.4
Depreciation and amortization	**156.6**	139.4
Accretion of asset retirement obligations	**11.2**	10.7
Deferred income taxes	**27.8**	30.5
Investment tax credit adjustments	**(1.8)**	(1.8)
Deferred fuel costs	**4.0**	(24.9)
Pension and postemployment benefits	**(36.9)**	(98.1)
Net gain on sales of investments and other assets	**(1.5)**	(13.7)
Equity in earnings of affiliates less than dividends received	**3.3**	8.7
Changes in		
Accounts receivable	**119.2**	(559.4)
Mark-to-market energy assets and liabilities	**4.0**	37.1
Risk management assets and liabilities	**2.2**	(61.6)
Materials, supplies and fuel stocks	**71.9**	44.8
Other current assets	**(25.9)**	(40.9)
Accounts payable	**(121.6)**	486.0
Other current liabilities	**7.4**	190.2
Other	**(0.8)**	28.8
Net cash provided by operating activities	**331.6**	242.8
Cash Flows From Investing Activities		
Purchases of property, plant and equipment	**(171.3)**	(145.2)
Contributions to nuclear decommissioning trust funds	**(8.8)**	(4.4)
Sales of investments and other assets	**6.7**	89.8
Other investments	**(7.4)**	(21.9)
Net cash used in investing activities	**(180.8)**	(81.7)
Cash Flows From Financing Activities		
Net (maturity) issuance of short-term borrowings	**(2.1)**	1.9
Proceeds from issuance of common stock	**15.2**	10.1
Repayment of long-term debt	**(2.4)**	(134.9)
Common stock dividends paid	**(43.5)**	(39.6)

Three Months Ended March 31,	2004	2003
Other	**1.5**	(1.4)
Net cash used in financing activities	**(31.3)**	(163.9)
Net Increase (Decrease) in Cash and Cash Equivalents	**119.5**	(2.8)
Cash and Cash Equivalents at Beginning of Period	**721.3**	615.0
Cash and Cash Equivalents at End of Period	**$ 840.8**	$ 612.2

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

CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

Baltimore Gas and Electric Company and Subsidiaries

Three Months Ended March 31,	2004	2003
	(In millions)	
Revenues		
Electric revenues	**$ 484.4**	$ 486.3
Gas revenues	**319.5**	303.5
Total revenues	**803.9**	789.8
Expenses		
Operating expenses		
Electricity purchased for resale	**240.4**	243.6
Gas purchased for resale	**216.0**	203.1
Operations and maintenance	**92.6**	77.4
Depreciation and amortization	**59.9**	55.9
Taxes other than income taxes	**45.2**	45.2
Total expenses	**654.1**	625.2
Income from Operations	**149.8**	164.6
Other Income	**1.0**	0.3
Fixed Charges		
Interest expense	**25.4**	30.0
Allowance for borrowed funds used during construction	**(0.3)**	(0.5)
Total fixed charges	**25.1**	29.5
Income Before Income Taxes	**125.7**	135.4
Income Taxes	**49.7**	53.6
Net Income	**76.0**	81.8
Preference Stock Dividends	**3.3**	3.3
Earnings Applicable to Common Stock	**$ 72.7**	$ 78.5

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

CONSOLIDATED BALANCE SHEETS

Baltimore Gas and Electric Company and Subsidiaries

	March 31, **2004***	*December 31,* **2003**
	(In millions)	
Assets		
Current Assets		
Cash and cash equivalents	**$ 7.9**	$ 11.0
Accounts receivable (net of allowance for uncollectibles of **$11.7** and $10.7, respectively)	**359.1**	354.8
Investment in cash pool, affiliated company	**358.8**	230.2
Accounts receivable, affiliated companies	**1.6**	4.5
Fuel stocks	**14.9**	62.8
Materials and supplies	**32.8**	29.9
Prepaid taxes other than income taxes	**21.5**	42.8
Other	**9.3**	9.9
Total current assets	**805.9**	745.9
Other Assets		
Receivable, affiliated company	**159.4**	131.6
Other	**92.1**	90.4
Total other assets	**251.5**	222.0
Utility Plant		
Plant in service		
Electric	**3,624.7**	3,599.3
Gas	**1,071.4**	1,064.7
Common	**460.9**	467.7
Total plant in service	**5,157.0**	5,131.7
Accumulated depreciation	**(1,832.9)**	(1,807.7)
Net plant in service	**3,324.1**	3,324.0
Construction work in progress	**124.3**	130.5
Plant held for future use	**4.5**	4.5
Net utility plant	**3,452.9**	3,459.0
Deferred Charges		
Regulatory assets (net)	**211.1**	229.5
Other	**48.2**	50.2

		March 31, 2004*		December 31, 2003
Total deferred charges		**259.3**		279.7
Total Assets	**$**	**4,769.6**	$	4,706.6

** Unaudited*

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

CONSOLIDATED BALANCE SHEETS

Baltimore Gas and Electric Company and Subsidiaries

	March 31, **2004***	*December 31,* **2003**
	(In millions)	
Liabilities and Equity		
Current Liabilities		
Current portion of long-term debt	**$ 350.6**	$ 330.6
Accounts payable	**83.8**	111.2
Accounts payable, affiliated companies	**189.1**	151.7
Customer deposits	**60.7**	59.7
Accrued taxes	**63.1**	33.0
Accrued interest	**34.5**	22.3
Other	**15.8**	43.3
Total current liabilities	**797.6**	751.8
Deferred Credits and Other Liabilities		
Deferred income taxes	**594.8**	585.8
Postretirement and postemployment benefits	**279.7**	279.2
Other	**47.8**	49.5
Total deferred credits and other liabilities	**922.3**	914.5
Long-term Debt		
First refunding mortgage bonds of BGE	**476.1**	476.1
Other long-term debt of BGE	**919.6**	919.6
6.20% deferrable interest subordinated debentures due October 15, 2043 to wholly owned BGE Capital Trust II relating to trust preferred securities	**257.7**	257.7
Long-term debt of nonregulated businesses	**25.0**	25.0
Unamortized discount and premium	**(3.8)**	(4.1)
Current portion of long-term debt	**(350.6)**	(330.6)
Total long-term debt	**1,324.0**	1,343.7
Minority Interest	**18.8**	18.9
Preference Stock Not Subject to Mandatory Redemption	**190.0**	190.0
Common Shareholder's Equity		
Common stock	**912.2**	912.2
Retained earnings	**603.9**	574.7
Accumulated other comprehensive income	**0.8**	0.8
Total common shareholder's equity	**1,516.9**	1,487.7

		March 31, 2004*		December 31, 2003
Commitments, Guarantees, and Contingencies (see Notes)				
Total Liabilities and Equity	**$**	**4,769.6**	$	4,706.6

** Unaudited*

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

CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

Baltimore Gas and Electric Company and Subsidiaries

Three Months Ended March 31,	2004	2003
	(In millions)	
Cash Flows From Operating Activities		
Net income	**$ 76.0**	$ 81.8
Adjustments to reconcile to net cash provided by operating activities		
Depreciation and amortization	**60.7**	56.7
Deferred income taxes	**9.3**	17.6
Investment tax credit adjustments	**(0.5)**	(0.5)
Deferred fuel costs	**4.0**	(24.9)
Pension and postemployment benefits	**(26.5)**	(73.5)
Allowance for equity funds used during construction	**(0.5)**	(0.9)
Changes in		
Accounts receivable	**(4.3)**	(33.8)
Receivables, affiliated companies	**2.9**	48.7
Materials, supplies, and fuel stocks	**45.0**	23.7
Other current assets	**21.9**	20.4
Accounts payable	**(27.4)**	22.6
Accounts payable, affiliated companies	**37.4**	(14.0)
Other current liabilities	**15.8**	45.1
Other	**8.2**	9.5
Net cash provided by operating activities	**222.0**	178.5
Cash Flows From Investing Activities		
Utility construction expenditures (excluding AFC)	**(54.6)**	(40.9)
Investment in cash pool at parent	**(128.6)**	(0.6)
Sales of investments and other assets	**4.9**	
Net cash used in investing activities	**(178.3)**	(41.5)
Cash Flows From Financing Activities		
Distribution to parent	**(43.5)**	
Repayment of long-term debt		(134.8)
Preference stock dividends paid	**(3.3)**	(3.3)
Net cash used in financing activities	**(46.8)**	(138.1)
Net Decrease in Cash and Cash Equivalents	**(3.1)**	(1.1)
Cash and Cash Equivalents at Beginning of Period	**11.0**	10.2

Three Months Ended March 31,	**2004**	2003
Cash and Cash Equivalents at End of Period	**$ 7.9**	$ 9.1

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Various factors can have a significant impact on our results for interim periods. This means that the results for this quarter are not necessarily indicative of future quarters or full year results given the seasonality of our business.

Our interim financial statements on the previous pages reflect all adjustments that management believes are necessary for the fair presentation of the financial position and results of operations for the interim periods presented. These adjustments are of a normal recurring nature.

Basis of Presentation

This Quarterly Report on Form 10-Q is a combined report of Constellation Energy Group, Inc. (Constellation Energy) and Baltimore Gas and Electric Company (BGE). References in this report to "we" and "our" are to Constellation Energy and its subsidiaries, collectively. References in this report to the "regulated business(es)" are to BGE.

Earnings Per Share

Basic earnings per common share (EPS) is computed by dividing earnings applicable to common stock by the weighted-average number of common shares outstanding for the period. Diluted EPS reflects the potential dilution of common stock equivalent shares that could occur if securities or other contracts to issue common stock were exercised or converted into common stock. Our dilutive common stock equivalent shares consist of stock options of 1.1 million for the quarter ended March 31, 2004. There were no stock options excluded from the computation of diluted EPS for the quarter ended March 31, 2004. Stock options to purchase approximately 5.0 million shares during the quarter ended March 31, 2003 were not dilutive and were excluded from the computation of diluted EPS for that period.

Stock-Based Compensation

Under our long-term incentive plans, we granted stock options, performance and service-based restricted stock, and equity to officers, key employees, and members of the Board of Directors. As permitted by Statement of Financial Accounting Standards (SFAS) No. 123, *Accounting for Stock-Based Compensation*, we measure our stock-based compensation using the intrinsic value method in accordance with Accounting Principles Board Opinion (APB) No. 25, *Accounting for Stock Issued to Employees*, and related interpretations. We discuss these plans and accounting further in *Note 14* of our 2003 Annual Report on Form 10-K.

The following table illustrates the effect on net income and earnings per share had we applied the fair value recognition provision of SFAS No. 123 to all outstanding stock options and stock awards in each period.

Quarter Ended March 31,

		2004		**2003**
		(In millions, except per share amounts)		
Net income (loss), as reported	**$**	**66.2**	$	(131.4)
Add: Stock-based compensation expense determined under intrinsic value method and included in reported net income (loss), net of related tax effects		**2.1**		0.9
Deduct: Stock-based compensation expense determined under fair value based method for all awards, net of related tax effects		**(3.6)**		(3.0)
Pro-forma net income (loss)	**$**	**64.7**	$	(133.5)
Earnings (loss) per share:				
Basic as reported	**$**	**0.39**	$	(0.80)
Basic pro forma	**$**	**0.38**	$	(0.81)
Diluted as reported	**$**	**0.39**	$	(0.80)
Diluted pro forma	**$**	**0.38**	$	(0.81)

Accretion of Asset Retirement Obligations

SFAS No. 143, *Accounting for Asset Retirement Obligations,* provides the accounting requirements for recognizing an estimated liability for legal obligations associated with the retirement of tangible long-lived assets. We measure the liability at fair value when incurred and capitalize a corresponding amount as part of the book value of the related long-lived assets. The increase in the capitalized cost is included in determining depreciation expense over the estimated useful life of these assets. Since the fair value of the asset retirement obligations is determined using a present value approach, accretion of the liability due to the passage of time is recognized each period to "Accretion of asset retirement obligations" in our Consolidated Statements of Income until the settlement of the liability. We record a gain or loss when the liability is settled after retirement.

The change in our "Asset retirement obligations" liability during 2004 was as follows:

		(In millions)
Liability at January 1, 2004	$	595.9
Accretion expense		11.2
Other		(2.0)
Liabilities incurred		
Liabilities settled		
Revisions to cash flows		
Liability at March 31, 2004	$	605.1

"Other" in the table above represents the asset retirement obligation associated with our geothermal facility in Hawaii that has been reclassified as a liability held for sale at March 31, 2004. We expect that at the time of the sale, the asset retirement obligation will be transferred to the buyer of the geothermal facility. We discuss the transfer of the geothermal facility assets and liabilities to held for sale in more detail in the *Loss from Discontinued Operations* section below.

Net Gain on Sales of Investments and Other Assets

2004

During the first quarter of 2004, our other nonregulated businesses recognized $1.5 million pre-tax, or $1.0 million after-tax, gains on the sale of non-core assets as follows:

- $1.1 million pre-tax gain on an installment sale of real estate, and
- $0.4 million pre-tax gain on the sale of a financial investment, as we continue to liquidate this operation.

2003

During the first quarter of 2003, our other nonregulated businesses recognized $13.7 million pre-tax, or $8.3 million after-tax, gains on the sale of non-core assets as follows:

- a $7.2 million pre-tax gain on the sale of an oil tanker to the U.S. Navy,
- a $5.3 million pre-tax gain on the favorable settlement of a contingent obligation we had previously reserved relating to the sale of our Guatemalan power plant operation in the fourth quarter of 2001, and
- a $1.2 million pre-tax gain on an installment sale of a parcel of real estate.

Loss from Discontinued Operations

In the fourth quarter of 2003, we began to re-evaluate our strategy regarding our geothermal generating facility in Hawaii. The reevaluation of our strategy included soliciting bids to determine the level of interest in the project. As of December 31, 2003, management determined that disposal of the project was more likely than not to occur. As a result, we evaluated our facility for impairment as of December 31, 2003, in accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, and determined that the assets were not impaired primarily due to indicative bids from third parties above the carrying value of the assets.

In March 2004, after reviewing final binding offers, management committed to a plan to sell the facility that met the "held for sale" criteria under SFAS No. 144. Under SFAS No. 144, we record assets and liabilities held for sale at the lesser of the carrying amount or fair value less cost to sell.

The fair value of the facility as of March 31, 2004, based on the bids under consideration was below carrying value, therefore, we recorded a $71.6 million pre-tax, or $47.3 million after-tax, impairment charge during the first quarter of 2004. We reported the after-tax impairment charge as a component of "Loss from discontinued operations" in our Consolidated Statements of Income.

Additionally we recognized the $1.5 million pre-tax, or $1.0 million after-tax, of earnings from the geothermal facility for the quarter ended March 31, 2004 as a component of "Loss from discontinued operations." We have not reclassified the prior year results of operations, which were reported under the equity method as "Nonregulated revenues" because we believe that reclassification of immaterial prior period results would be less useful than consistent reporting of prior year amounts. The geothermal facility had a $4.7 million net loss, including a $1.1 million cumulative effect of change in accounting principle for the adoption of SFAS No. 143, during the quarter ended March 31, 2003.

Presented in the table below are the components of the assets and liabilities held for sale which are included in our merchant energy business:

At March 31, 2004

		(In millions)
Assets held for sale		
Cash	$	6.2
Accounts receivable		1.6
Property, plant and equipment		65.0
Other assets		14.8
Total	$	87.6
Liabilities associated with assets held for sale		
Accounts payable	$	0.3
Long-term debt		40.3
Asset retirement obligation		2.0
Other liabilities		4.9
Total	$	47.5

On April 22, 2004, we executed a definitive agreement to sell the geothermal facility subject to standard closing conditions. We expect to record an additional loss on discontinued operations of approximately $4 million after-tax in the second quarter of 2004. The additional loss may vary from the current estimate based upon the actual sales price and costs to resolve remaining contingencies upon closing, which is expected to occur in mid-2004.

Information by Operating Segment

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

Our nonregulated merchant energy business in North America includes:

fossil, nuclear, and hydroelectric generating facilities and interests in qualifying facilities, fuel processing facilities, and power projects in the United States,

origination of structured transactions (such as load-serving and power purchase agreements), and risk management services to various customers (including hedging of output from generating facilities and fuel costs),

electric and gas retail energy services to commercial and industrial customers, and

generation and consulting services.

Our regulated electric business purchases, transmits, distributes, and sells electricity in Maryland.

Our regulated gas business purchases, transports, and sells natural gas in Maryland.

Our remaining nonregulated businesses:

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

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

Our Merchant Energy, Regulated Electric, and Regulated Gas reportable segments are strategic businesses based principally upon regulations, products, and services that require different technology and marketing strategies. We evaluate the performance of these segments based on net income. We account for intersegment revenues using market prices. A summary of information by operating segment is shown in the table on the next page.

For the three months ended March 31,	Reportable Segments: Merchant Energy Business	Reportable Segments: Regulated Electric Business	Reportable Segments: Regulated Gas Business	Other Nonregulated Businesses	Eliminations	Consolidated
			(In millions)			
2004						
Unaffiliated revenues	**$ 2,130.5**	**$ 484.4**	**$ 317.9**	**$ 103.8**	**$**	**$ 3,036.6**
Intersegment revenues	**254.3**		**1.6**		**(255.9)**	
Total revenues	**2,384.8**	**484.4**	**319.5**	**103.8**	**(255.9)**	**3,036.6**
Loss from discontinued operations	**(46.3)**					**(46.3)**
Net (loss) income	**(6.8)**	**45.1**	**27.8**	**0.1**		**66.2**
2003						
Unaffiliated revenues	$ 1,389.9	$ 486.3	$ 298.2	$ 155.6	$	$ 2,330.0
Intersegment revenues	287.2		5.3		(292.5)	
Total revenues	1,677.1	486.3	303.5	155.6	(292.5)	2,330.0
Cumulative effects of changes in accounting principles	(198.4)					(198.4)
Net (loss) income	(218.9)	50.2	28.6	8.7		(131.4)

Pension and Postretirement Benefits

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

Three Months Ended March 31,	2004	2003
	(In millions)	
Components of net periodic pension benefit cost		
Service cost	**$ 8.6**	$ 8.8
Interest cost	**19.3**	21.3
Expected return on plan assets	**(22.4)**	(24.9)
Amortization of unrecognized prior service cost	**1.3**	1.5
Recognized net actuarial loss	**3.5**	1.3
Amount capitalized as construction cost	**(0.7)**	(0.9)
Net periodic pension benefit cost	**$ 9.6**	$ 7.1

We plan to contribute a total of between $50 million and $60 million to our qualified pension plans in 2004, even though there is no IRS required minimum contribution. We made a $50 million contribution on January 16, 2004.

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

Three Months Ended March 31,	2004	2003
	(In millions)	
Components of net periodic postretirement benefit cost		
Service cost	**$ 1.3**	$ 1.8
Interest cost	**6.6**	7.5
Amortization of transition obligation	**0.6**	0.6
Recognized net actuarial loss	**2.0**	1.6
Amortization of unrecognized prior service cost	**(1.0)**	(1.0)
Amount capitalized as construction cost	**(2.4)**	(2.1)
Net periodic postretirement benefit cost	**$ 7.1**	$ 8.4

Our non-qualified pension plans and our postretirement benefit programs are not funded, however we have trust assets securing certain executive pension benefits. We estimate that we will incur approximately $3 million in pension benefit payments for our non-qualified pension plans and approximately $30 million for retiree health and life insurance benefit payments during 2004.

Financing Activities

During the first quarter of 2004, we decided to continue our ownership in a synthetic fuel processing facility in South Carolina. We discuss this facility in more detail in the *Income Tax Credits* section below. In connection with our decision to continue with our ownership in this facility, we are committed to making fixed payments until the end of 2007. We have recorded a liability of $39.3 million in "Long-term debt" in our Consolidated Balance Sheets for these fixed payments.

Additionally, under our continuous offering program, employee benefit plans, and shareholder investment plans we issued $15.2 million of common stock during the quarter ended March 31, 2004.

Income Tax Credits

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

As of March 31, 2004, we have recognized cumulative tax benefits associated with Section 29 credits of $100.1 million, of which $22.1 million was recognized during the quarter ended March 31, 2004.

We own a minority ownership in four synthetic fuel facilities located in Ohio, Virginia, and West Virginia. These facilities have received private letter rulings from the IRS. In January 2004, the IRS concluded its examination of the partnership that owns these facilities for the tax years 1998 through 2001 and the IRS did not disallow any of the previously recognized synthetic fuel credits. We are awaiting final written notice of the resolution of the examination from the IRS.

In 2003, we purchased 99% ownership in a South Carolina facility that produces synthetic fuel. We did not recognize in our Consolidated Statements of Income the tax benefit of approximately $36 million for credits claimed on our South Carolina facility in 2003 pending receipt of a favorable private letter ruling. On January 12, 2004, we submitted our request for a private letter ruling to the IRS for our South Carolina facility.

In the first quarter of 2004, we implemented certain measures to mitigate our risk in the event that synthetic fuel tax credits associated with production at our South Carolina facility after January 1, 2004 were disallowed by the IRS. By mitigating our risk, we believe we obtained assurance that it is highly probable that the financial benefit of tax credits claimed in 2004 will be sustained. Accordingly, in the first quarter 2004, we recognized the tax benefit of $13.5 million for synthetic tax credits related to the 2004 production at our South Carolina facility.

On April 15, 2004, we received a favorable private letter ruling. We believe receipt of the private letter ruling provides assurance that it is highly probable that the credits will be sustained. Therefore, we expect to recognize the tax benefit of approximately $36 million of the credits claimed in 2003 in our Consolidated Statements of Income during the quarter ended June 30, 2004, the quarter in which we received the private letter ruling.

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

Commitments, Guarantees, and Contingencies

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

- purchase of electric generating capacity and energy,
- procurement and delivery of fuels,
- the capacity and transmission and transportation rights for the physical delivery of energy to meet our obligations to our customers, and

long-term service agreements, capital for construction programs and other.

Our merchant energy business has committed to long-term service agreements and other purchase commitments for our plants.

Our regulated gas business enters into various long-term contracts for the procurement, transportation, and storage of gas.

Our other nonregulated businesses have committed to gas purchases, as well as to contribute additional capital for construction programs and joint ventures in which they have an interest.

Corporately, we have committed to long-term service agreements and other obligations related to our information technology systems.

At March 31, 2004, the total amount of commitments was $4,178.4 million, which are primarily related to our merchant energy business.

Planned Acquisition

On November 25, 2003, we announced an agreement with Rochester Gas and Electric (RG&E) to acquire the R.E. Ginna Nuclear Power Plant (Ginna) located north of Rochester, New York. Upon closing the acquisition of this 495 MW facility, we will own and operate three nuclear power stations. We expect to acquire this facility in mid-2004.

The estimated purchase price for the Ginna plant is approximately $400 million, excluding approximately $22 million for purchased nuclear fuel. RG&E will transfer approximately $202 million in decommissioning funds at the time of closing. We believe this transfer will be sufficient to meet the decommissioning requirements of the facility.

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

Long-Term Power Sales Contracts

We enter into long-term power sales contracts in connection with our load-serving activities. We also enter into long-term power sales contracts associated with certain of our power plants. Our load-serving power sales contracts extend for terms through 2012 and provide for the sale of full requirements energy to electricity distribution utilities and certain retail customers. Our power sales contracts associated with our power plants extend for terms into 2011 and provide for the sale of all or a portion of the actual output of certain of our power plants. All long-term contracts were executed at pricing that approximated market rates, including profit margin, at the time of execution.

Guarantees

The terms of our guarantees are as follows:

	Expiration				
	2004	2005-2006	2007-2008	Thereafter	Total
			(In millions)		
Competitive Supply	$ 3,306.9	$ 495.0	$ 292.0	$ 498.1	$ 4,592.0
Other	9.9	11.6		863.7	885.2
Total	$ 3,316.8	$ 506.6	$ 292.0	$ 1,361.8	$ 5,477.2

At March 31, 2004, Constellation Energy had a total of $5,477.2 million guarantees outstanding related to loans, credit facilities, and contractual performance of certain of its subsidiaries as described below. These guarantees do not represent our incremental obligations and we do not expect to fund the full amount under these guarantees.

Constellation Energy guaranteed $4,592.0 million on behalf of our subsidiaries for competitive supply activities. These guarantees are put into place in order to allow our subsidiaries the flexibility needed to conduct business with counterparties without having to post substantial cash collateral. While the face amount of these guarantees is $4,592.0 million, our calculated fair value of obligations covered by these guarantees was $1,125.8 million at March 31, 2004. If the parent company was required to fund subsidiary obligations, the total amount at current market prices is $1,125.8 million. The recorded fair value of obligations in our Consolidated Balance Sheets for these guarantees was $620.4 million at March 31, 2004.

Constellation Energy guaranteed $552.2 million primarily on behalf of our nuclear facilities related to nuclear insurance and decommissioning.

Constellation Energy guaranteed $34.7 million on behalf of our other nonregulated businesses primarily for loans and performance bonds of which $25.6 million was recorded in our Consolidated Balance Sheets at March 31, 2004.

Our merchant energy business guaranteed $18.2 million for loans and other performance guarantees related to certain power projects in which we have an investment.

Our other nonregulated business guaranteed $16.8 million for performance bonds.

BGE guaranteed two-thirds of certain debt of Safe Harbor Water Power Corporation, an unconsolidated investment. At March 31, 2004, Safe Harbor Water Power Corporation had outstanding debt of $20.0 million. The maximum amount of BGE's guarantee is $13.3 million.

BGE guaranteed the Trust Preferred Securities of $250.0 million of BGE Capital Trust II, an unconsolidated investment, as discussed in more detail in *Note 9* of our 2003 Annual Report on Form 10-K.

The total fair value of the obligations for our guarantees recorded in our Consolidated Balance Sheets was $646.0 million and not the $5.5 billion of total guarantees. We assess the risk of loss from these guarantees to be minimal.

Environmental Matters

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

- air quality,
- water quality, and
- treatment, storage, and disposal of solid and hazardous waste.

Clean Air Act

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

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

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

The EPA established new National Ambient Air Quality Standards for very fine particulates and revised standards for ozone. In April 2004, the EPA identified the areas that would be in ozone nonattainment for the new standards. The affected states will be required to submit plans for compliance within three years. While the new standards may require increased controls at some of our fossil generating plants in the future, planning and implementation of unit specific requirements will take place over the next several years. We cannot estimate the cost of these increased controls until the states and the EPA finalize their plans for meeting these standards.

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

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

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

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

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

The Clean Air Act required the EPA to evaluate the public health impacts of emissions of mercury, a hazardous air pollutant, from coal-fired plants. The EPA decided to control mercury emissions from coal-fired plants. On December 15, 2003, the EPA proposed two alternatives for controlling mercury emissions from generating facilities. The EPA may require the installation of mercury reduction equipment. Alternatively, the EPA may revise standards to allow for the purchase of allowances. Compliance could be required as soon as 2007, or by 2010 depending on which alternative is selected. We believe final regulations could be issued in 2004 and could affect all oil-fired and coal-fired boilers. The cost of compliance with the final regulations could be material.

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

Clean Water Act

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

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

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

Waste Disposal

The EPA and several state agencies have notified us that we are considered a potentially responsible party with respect to the clean-up of certain environmentally contaminated sites owned and operated by others. We cannot estimate the clean-up costs for all of these sites.

However, based on a Record of Decision (ROD) issued by the EPA in 1997, we can estimate that BGE's current 15.47% share of the reasonably possible clean-up costs at one of these sites, Metal Bank of America, a metal reclaimer in Philadelphia, could be as much as $1.3 million higher than amounts we believe are probable and have recorded as a liability in our Consolidated Balance Sheets. There has been no significant regulatory activity with respect to actual site remediation since the EPA's ROD in 1997. EPA and the potentially responsible parties, including BGE, are currently pursuing claims against Metal Bank of America for an equitable share of expected site remediation costs.

In 1999, the EPA proposed to add the 68th Street Dump in Baltimore, Maryland to the Comprehensive Environmental Response, Compensation and Liability Act ("Superfund") National Priorities List ("NPL"), which is its list of sites targeted for clean-up and enforcement, and sent a general notice letter to BGE and 19 other parties identifying them as potentially liable parties at the 68th Street Dump site. In April 2003, EPA re-proposed the 68th Street site to the NPL, but decided not to include the site in its September 2003 update. We and other potentially responsible parties formed the 68th Street Coalition in March 2004 with the intent of entering into consent order negotiations with the EPA to investigate clean-up options for the site. At this stage, it is not possible to predict the outcome of those discussions or our share of the liability. However, the costs could have a material effect on our financial results.

In late December 1996, BGE signed a consent order with the Maryland Department of the Environment that required BGE to implement remedial action plans for contamination at and around the Spring Gardens site, located in Baltimore, Maryland. The Spring Gardens site was once used to manufacture gas from coal and oil. Based on the remedial action plans, the costs BGE considers to be probable to remedy the contamination are estimated to total $47 million. BGE recorded these costs as a liability in its Consolidated Balance Sheets and deferred these costs, net of accumulated amortization and amounts it recovered from insurance companies, as a regulatory asset. Because of the results of studies at this site, it is reasonably possible that additional costs could exceed the amount BGE recognized by approximately $14 million. Through March 31, 2004, BGE spent approximately $40 million for remediation at this site. BGE also investigated other small sites where gas was manufactured in the past. We do not expect the clean-up costs of the remaining smaller sites to have a material effect on our financial results.

The EPA issued its ROD for the Kane and Lombard Drum site located in Baltimore, Maryland on September 30, 2003. The ROD specifies the clean-up plan for the site, consisting of enhanced reductive dechlorination, a soil management plan, and institutional controls. The ROD was consistent with the proposed remedy the EPA released in December 2002. We expect the EPA to approach the potentially responsible parties regarding implementation of the plan in 2004. The total clean-up costs are estimated to be $7.3 million. We estimate our current share of site-related costs to be 11.1%. Our share of these future costs has not been determined and it may vary from the current estimate. In December 2002, we recorded a liability in our Consolidated Balance Sheets for our share of the clean-up costs that we believe is probable.

Nuclear Insurance

We maintain nuclear insurance coverage for Calvert Cliffs and Nine Mile Point in four program areas: liability, worker radiation, property, and accidental outage. These policies contain certain industry standard exclusions, including, but not limited to, ordinary wear and tear and war. We discuss our insurance programs in *Note 12* of our 2003 Annual Report on Form 10-K.

Non-nuclear Property Insurance

Our conventional property insurance provides coverage of $1.0 billion per occurrence for Certified acts of terrorism as defined under the Terrorism Risk Insurance Act. Certified acts of terrorism are determined by the Secretary of State and Attorney General of the United States and primarily are based upon the occurrence of significant acts of international terrorism. If a terrorist act occurs at any of our facilities, it could have a significant adverse impact on our financial results. We discuss our insurance programs in *Note 12* of our 2003 Annual Report on Form 10-K.

SFAS No. 133 Hedging Activities

We are exposed to market risk, including changes in interest rates and the impact of market fluctuations in the price and transportation costs of electricity, natural gas, and other commodities. We discuss our market risk in more detail on page 49.

Interest Rates

We use interest rate swaps to manage our interest rate exposures associated with new debt issuances. These swaps are designated as cash-flow hedges under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities, as amended,* with gains and losses, net of associated deferred income tax effects, recorded in "Accumulated other comprehensive income" in our Consolidated Balance Sheets, in anticipation of planned financing transactions. We reclassify gains and losses on the hedges from "Accumulated other comprehensive income" into "Interest expense" during the periods in which the interest payments being hedged occur.

At March 31, 2004, we have net unrealized pre-tax gains of $20.5 million related to interest rate hedges recorded in "Accumulated other comprehensive income." We expect to reclassify $2.9 million of pre-tax net gains on these swap contracts from "Accumulated other comprehensive income" into "Interest expense" during the next twelve months.

Commodity Prices

At March 31, 2004 our merchant energy business had designated certain purchase and sale contracts as cash-flow hedges of forecasted transactions for the years 2004 through 2011 under SFAS No. 133.

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

At March 31, 2004, our merchant energy business has net unrealized pre-tax gains of $134.5 million on these hedges recorded in "Accumulated other comprehensive income." We expect to reclassify $357.6 million of net pre-tax gains on cash-flow hedges from "Accumulated other comprehensive income" into earnings during the next twelve months based on the market prices at March 31, 2004. However, the actual amount reclassified into earnings could vary from the amounts recorded at March 31, 2004 due to future changes in market prices. We recognized into earnings a pre-tax gain of $9.3 million for the quarter ended March 31, 2004 and a pre-tax loss of $0.2 million for the quarter ended March 31, 2003 related to the ineffective portion of our hedges.

Accounting Standards Adopted

FIN 46R

In January 2003, the Financial Accounting Standards Board (FASB) issued Interpretation No. (FIN) 46, *Consolidation of Variable Interest Entities*, which was subsequently revised in its entirety with the issuance of FIN 46R in December 2003.

FIN 46R establishes conditions under which an entity must be consolidated based upon variable interests rather than voting interests. Variable interests are ownership interests or contractual relationships that enable the holder to share in the financial risks and rewards resulting from the activities of a Variable Interest Entity (VIE). A VIE can be a corporation, partnership, trust, or any other legal structure used for business purposes. An entity is considered a VIE under FIN 46R if it does not have an equity investment sufficient for it to finance its activities without assistance from variable interests or if its equity investors lack any of the following characteristics of a controlling financial interest:

- control through voting rights,
- obligation to absorb expected losses or
- right to receive expected residual returns.

FIN 46R requires us to consolidate VIEs for which we are the primary beneficiary and to disclose certain information about significant variable interests we hold. The primary beneficiary of a VIE is the entity that receives the majority of a VIE's expected losses, expected residual returns, or both.

FIN 46R was effective March 31, 2004 for all VIEs except special purpose entities (SPEs), for which the effective date was December 31, 2003. Therefore, at December 31, 2003, we and BGE deconsolidated BGE Capital Trust II, an SPE established to issue Trust Preferred Securities as described in *Note 9* of our 2003 Annual Report on Form 10-K because BGE is not the primary beneficiary. As a result, we currently record $257.7 million of Deferrable Interest Subordinated Debentures due to BGE Capital Trust II and $7.7 million equity investment in BGE Capital Trust II in "Other investments" in our and BGE's Consolidated Balance Sheets.

As a result of adopting the remainder of the provisions of FIN 46R as of March 31, 2004, we were not required to consolidate or deconsolidate any non-SPE entities with which we are involved through variable interests. We had preliminarily determined that we were the primary beneficiary for an unconsolidated investment in a hydroelectric generating plant located in Pennsylvania because our two-thirds voting interest is disproportionate to our 50% interest in the plant's earnings. However, we subsequently determined that the entity is not a VIE because less than substantially all of the plant's activities are conducted on our behalf, and therefore we do not have to consolidate the entity.

We have a significant interest in the following VIEs for which we are not the primary beneficiary:

VIE	Nature of Involvement	Date of Involvement
Power projects and fuel supply entities	Equity investment, Guarantees	Prior to 2003
Natural gas producing facility	Volumetric and price swap	July 2003

The following is summary information about these entities as of March 31, 2004:

		(In millions)
Total assets	$	304
Total liabilities		161
Our ownership interest		40
Other ownership interests		103
Our maximum exposure to loss		125

The maximum exposure to loss represents the loss that we would incur in the unlikely event that our interests in all of these entities were to become worthless and we were required to fund the full amount of all guarantees associated with these entities. Our maximum exposure to loss as of March 31, 2004 consists of the following:

- the carrying amount of our investment totaling $41 million,
- debt and performance guarantees totaling $12 million, and
- volumetric and price variability of up to $72 million associated with a natural gas producer swap, based on contract volumes and gas prices as of March 31, 2004.

We assess the risk of a loss equal to our maximum exposure to be remote.

Related Party Transactions BGE

Income Statement

BGE is providing standard offer service to customers at fixed rates over various time periods during the initial transition period from July 1, 2000 to June 30, 2006, for those customers that do not choose an alternate supplier. Our wholesale marketing and risk management operation is under contract to provide BGE the energy and capacity required to meet its standard offer service obligations for the transition period. The cost of BGE's purchased energy from nonregulated affiliates of Constellation Energy to meet its standard offer service obligation was $240.4 million for the quarter ended March 31, 2004 compared to $243.5 million for the same period in 2003.

In addition, Constellation Energy charges BGE for the costs of certain corporate functions. Certain costs are directly assigned to BGE. We allocate other corporate function costs based on a total percentage of expected use by BGE. Management believes this method of allocation is reasonable and approximates the cost BGE would have incurred as an unaffiliated entity. These costs were approximately $17.6 million for the quarter ended March 31, 2004 compared to $14.7 million for the quarter ended March 31, 2003.

Balance Sheet

BGE participates in a cash pool under a Master Demand Note agreement with Constellation Energy. Under this arrangement, participating subsidiaries may invest in or borrow from the pool at market interest rates. Constellation Energy administers the pool and invests excess cash in short-term investments or issues commercial paper to manage consolidated cash requirements. BGE had invested $358.8 million at March 31, 2004 and $230.2 million at December 31, 2003 under this arrangement.

Amounts related to corporate functions performed at the Constellation Energy holding company, BGE's purchases to meet its standard offer service obligation, BGE's charges to Constellation Energy and its nonregulated affiliates for certain services it provides them, and the participation of BGE's employees in the Constellation Energy pension plan result in intercompany balances in BGE's Consolidated Balance Sheets.

Item 2. Management's Discussion

Management's Discussion and Analysis of Financial Condition and Results of Operations

Introduction and Overview

Constellation Energy Group, Inc. (Constellation Energy) is a North American energy company that conducts its business through various subsidiaries including a merchant energy business and Baltimore Gas and Electric Company (BGE). We describe our operating segments in the *Notes to Consolidated Financial Statements* on page 13.

This Quarterly Report on Form 10-Q is a combined report of Constellation Energy and BGE. References in this report to "we" and "our" are to Constellation Energy and its subsidiaries, collectively. References in this report to the "regulated business(es)" are to BGE.

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

Our wholesale marketing and risk management operation actively uses energy and energy-related commodities in order to manage our portfolio of energy purchases and sales to customers through structured transactions. As part of our risk management activities we trade power and gas to enable price discovery and facilitate the hedging of our load-serving and other risk management products and services. Within our trading function we allow limited risk-taking activities for profit. These activities are actively managed through daily value at risk and liquidity position limits. We discuss value at risk in more detail in the *Market Risk* section on page 49.

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

Our other nonregulated businesses:

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

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

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

- factors which affect our businesses,
- our earnings and costs in the periods presented,
- changes in earnings and costs between periods,
- sources of earnings,
- impact of these factors on our overall financial condition,

- expected future expenditures for capital projects, and
- expected sources of cash for future capital expenditures.

As you read this discussion and analysis, refer to our Consolidated Statements of Income on page 3, which present the results of our operations for the quarters ended March 31, 2004 and 2003. We analyze and explain the differences between periods in the specific line items of the Consolidated Statements of Income.

We have organized our discussion and analysis as follows:

- First, we discuss our strategy.
- We then describe the business environment in which we operate including how regulation, weather, and other factors affect our business.
- Next, we discuss our critical accounting policies. These are the accounting policies that are most important to both the portrayal of our financial condition and results and require management's most difficult, subjective or complex judgment.
- We highlight significant events that occurred in 2004 that are important to understanding our results of operations and financial condition.
- We then review our results of operations beginning with an overview of our total company results, followed by a more detailed review of those results by operating segment.
- We review our financial condition, addressing our sources and uses of cash, security ratings, capital resources, capital requirements, and commitments.
- We conclude with a discussion of our exposure to various market risks.

Strategy

We are pursuing a balanced strategy to distribute energy through our North American competitive supply activities and our regulated utility located in Maryland, BGE.

Our merchant energy business focuses on long-term, high-value sales of energy, capacity, and related products to large customers, including distribution utilities, municipalities, cooperatives, industrial customers, and commercial customers primarily in the regional markets in which end-use customer electricity rates have been deregulated and thereby separated from the cost of generation supply. These markets include:

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

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

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

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

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

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

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

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

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

Beginning in the fourth quarter of 2001, we undertook a number of initiatives to reduce our costs towards competitive levels and to ensure that our resources are focused on our core energy businesses. These initiatives included the implementation of workforce reduction programs, the acceleration of our exit strategy for certain non-core assets, and the implementation of productivity initiatives.

We are constantly reevaluating our strategies and might consider:

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

Business Environment

With the shift toward customer choice, competition, and the growth of our merchant energy business, various factors affect our financial results. We discuss these various factors in the *Forward Looking Statements* section on page 54. We discuss our market risks in the *Market Risk* section on page 49.

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

Merchant Competition

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

Increased competition that resulted from some of these initiatives in several states contributed in some instances to a reduction in electricity prices and put pressure on electric utilities to lower their costs, including the cost of purchased electricity. Some states that were considering deregulation have slowed their plans or postponed consideration of deregulation. In addition, other states are reconsidering deregulation. Our merchant energy business is also affected by regional regulatory or legislative decisions, which may impact our financial results and our ability to successfully execute our growth strategy.

We believe there is adequate growth potential in the current deregulated market. However, in response to regional market differences and to promote competitive markets, the Federal Energy Regulatory Commission (FERC) proposed initiatives promoting the formation of Regional Transmission Organizations and a standard market design. If approved, these market changes could provide additional opportunities for our merchant energy business. We discuss these initiatives in the *FERC Regulation Regional Transmission Organizations and Standard Market Design* section on page 26.

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

Regulated Electric Competition

We are facing competition in the sale of electricity to retail customers.

Maryland

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

- All customers can choose their electric energy supplier. BGE provides fixed price standard offer service over various time periods for different classes of customers that do not select an alternative supplier until June 30, 2006.
- While BGE does not sell electric commodity to all customers in its service territory, BGE does deliver electricity to all customers and provides meter reading, billing, emergency response, regular maintenance, and balancing services.
- BGE provides a market rate standard offer service for those commercial and industrial customers who are no longer eligible for fixed price standard offer service.

BGE residential base rates will not change before July 2006. While total residential base rates remain unchanged over the transition period (July 1, 2000 through June 30, 2006), annual standard offer service rate increases are offset by corresponding decreases in the competitive transition charge (CTC) that BGE receives from its customers.

Commercial and industrial customers have several service options that will fix electric energy rates through June 30, 2004 and transition charges through June 30, 2006.

Standard Offer Service

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

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

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

Standard Offer Service Provider of Last Resort (POLR)

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

In September 2003, the Maryland PSC approved a second settlement agreement. This phase deals with the bid procurement process that utilities must follow to obtain wholesale power supply to serve retail customers on standard offer service during the second transition period. The settlement contained a model request for proposals, a model wholesale power supply contract, and various requirements pertaining to, among other things, bidder qualifications and bid evaluation criteria. Bidding to supply BGE's standard offer service to commercial and industrial customers beyond June 30, 2004 occurred through a multi-round competitive bidding process in February and March 2004. BGE executed one and two-year contracts for commercial and industrial electric power supply totaling approximately 2,300 megawatts.

Regulated Gas Competition

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

Regulation by the Maryland PSC

In addition to electric restructuring, regulation by the Maryland PSC influences BGE's businesses. The Maryland PSC determines the rates that BGE can charge customers for the electric distribution and gas businesses. The Maryland PSC incorporates into BGE's electric rates the transmission rates determined by FERC. The rates for BGE's regulated gas business continue to consist of a "base rate" and a "fuel rate."

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

Electric Base Rates

BGE's electric rates are unbundled to show separate components for delivery service, competitive transition charges, standard offer services (generation), transmission, universal service, and certain taxes. As a result of the deregulation of electric generation in Maryland, BGE's residential electric base rates are frozen until June 30, 2006. Electric delivery service rates are frozen until June 30, 2004 for commercial and industrial customers. The generation and transmission components of rates are frozen for different time periods depending on the service options selected by those customers. We discuss the impact on base rates beyond 2004 in the *Regulated Electric Competition Maryland* section on page 24.

Gas Base Rate

The base rate is the rate the Maryland PSC allows BGE to charge its customers for the cost of providing them service, plus a profit. Gas base rates are not affected by seasonal changes.

Gas Fuel Rate

BGE charges its gas customers separately for natural gas purchases. The price charged for the natural gas is based on a market-based rates incentive mechanism approved by the Maryland PSC. We discuss market-based rates in more detail in the *Gas Cost Adjustments* section on page 42 and in *Note 1* of our 2003 Annual Report on Form 10-K.

FERC Regulation

Regional Transmission Organizations and Standard Market Design

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

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

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

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

Weather

Merchant Energy Business

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

BGE

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

However, the Maryland PSC allows us to record a monthly adjustment to our regulated gas business revenues to eliminate the effect of abnormal weather patterns. We discuss this further in the *Weather Normalization* section on page 42.

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

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

We show the number of heating degree-days in the quarters ended March 31, 2004 and 2003, and the percentage change in the number of degree-days between these periods in the following table:

Quarter Ended March 31,	**2004**	**2003**
Heating degree-days	**2,604**	2,759
Percent change from prior period	(5.6)%	

Other Factors

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

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

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

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

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

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

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

Accounting Standards Adopted

We discuss recently adopted accounting standards in the *Notes to Consolidated Financial Statements* on page 20.

Critical Accounting Policies

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

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

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

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

Management believes the following accounting policies represent critical accounting policies as defined by the SEC. We discuss our significant accounting policies, including those that do not require management to make difficult, subjective, or complex judgments or estimates, in *Note 1* of our 2003 Annual Report on Form 10-K.

Revenue Recognition Mark-to-Market Method of Accounting

Our merchant energy business enters into contracts for energy, other energy-related commodities, and related derivatives. We record merchant energy business revenues using two methods of accounting: accrual accounting and mark-to-market accounting. We describe our use of accrual accounting (including hedge accounting) in more detail in *Note 1* of our 2003 Annual Report on Form 10-K.

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

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

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

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

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

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

Market prices for energy and energy-related commodities vary based upon a number of factors, and changes in market prices affect both the recorded fair value of our mark-to-market energy contracts and the level of future revenues and costs associated with accrual-basis activities. Changes in the value of our mark-to-market energy contracts will affect our earnings in the period of the change, while changes in forward market prices related to accrual-basis revenues and costs will affect our earnings in future periods to the extent those prices are realized. We cannot predict whether, or to what extent, the factors affecting market prices may change, but those changes could be material and could affect us either favorably or unfavorably. We discuss our market risk in more detail in the *Market Risk* section on page 49.

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

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

We discuss the impact of mark-to-market accounting on our financial results in the *Results of Operations Merchant Energy Business* section on page 34.

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

Long-Lived Assets

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

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

For long-lived assets that are expected to be held and used, SFAS No. 144 provides that an impairment loss shall only be recognized if the carrying amount of an asset is not recoverable and exceeds its fair value. The carrying amount of an asset is not recoverable under SFAS No. 144 if the carrying amount exceeds the sum of the undiscounted future cash flows expected to result from the use and eventual disposition of the asset. Therefore, when we believe an impairment condition may have occurred, we are required to estimate the undiscounted future cash flows associated with a long-lived asset or group of long-lived assets. This necessarily involves judgment surrounding the inherent uncertainty of future cash flows.

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

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

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

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

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

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

Goodwill

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

Asset Retirement Obligations

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

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

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

Events of 2004

Loss from Discontinued Operations

In the fourth quarter of 2003, we began to re-evaluate our strategy regarding our geothermal generating facility in Hawaii. The reevaluation of our strategy included soliciting bids to determine the level of interest in the project. As of December 31, 2003, management had determined that disposal of the project was more likely than not to occur. As a result, we evaluated our facility for impairment as of December 31, 2003, in accordance with SFAS No. 144, and determined that the assets were not impaired primarily due to indicative bids from third parties above the carrying value of the assets.

In March 2004, after reviewing final binding offers, management committed to a plan to sell the facility that met the "held for sale" criteria under SFAS No. 144. Under SFAS No. 144, we record assets and liabilities held for sale at the lesser of the carrying amount or fair value less cost to sell.

The fair value of the facility as of March 31, 2004, based on the bids under consideration was below carrying value, therefore, we recorded a $71.6 million pre-tax, or $47.3 million after-tax, impairment charge during the first quarter of 2004. We reported the after-tax impairment charge as a component of "Loss from discontinued operations" in our Consolidated Statements of Income.

Additionally we recognized the $1.5 million pre-tax, or $1.0 million after-tax, of earnings from the geothermal facility for the quarter ended March 31, 2004 as a component of "Loss from discontinued operations." We have not reclassified the prior year results of operations, which were reported under the equity method as "Nonregulated revenues" because we believe that reclassification of immaterial prior period results would be less useful than consistent reporting of prior year amounts. The geothermal facility had a $4.7 million net loss, including a $1.1 million cumulative effect of change in accounting principle for the adoption of SFAS No. 143, during the quarter ended March 31, 2003.

Presented in the table below are the components of the assets and liabilities held for sale which are included in our merchant energy business:

At March 31, 2004

		(In millions)
Assets held for sale		
Cash	$	6.2
Accounts receivable		1.6
Property, plant, and equipment		65.0
Other assets		14.8
Total	$	87.6
Liabilities associated with assets held for sale		
Accounts payable	$	0.3
Long-term debt		40.3
Asset retirement obligation		2.0
Other liabilities		4.9
Total	$	47.5

On April 22, 2004, we executed a definitive agreement to sell the geothermal facility subject to standard closing conditions. We expect to record an additional loss on discontinued operations of approximately $4 million after-tax in the second quarter of 2004. The additional loss may vary from the current estimate based upon the actual sales price and costs to resolve remaining contingencies upon closing, which is expected in mid-2004.

Synthetic Fuel Tax Credits

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

As of March 31, 2004, we have recognized cumulative tax benefits associated with Section 29 credits of $100.1 million, of which $22.1 million was recognized during the quarter ended March 31, 2004.

We own a minority ownership in four synthetic fuel facilities located in Ohio, Virginia, and West Virginia. These facilities have received private letter rulings from the IRS. In January 2004, the IRS concluded its examination of the partnership that owns these facilities for the tax years 1998 through 2001 and the IRS did not disallow any of the previously recognized synthetic fuel credits. We are awaiting final written notice of the resolution of the examination from the IRS.

In 2003, we purchased 99% ownership in a South Carolina facility that produces synthetic fuel. We did not recognize in our Consolidated Statements of Income the tax benefit of approximately $36 million for credits claimed on our South Carolina facility in 2003 pending receipt of a favorable private letter ruling. On January 12, 2004, we submitted our request for a private letter ruling to the IRS for our South Carolina facility.

In the first quarter of 2004, we implemented certain measures to mitigate our risk in the event that synthetic fuel tax credits associated with production at our South Carolina facility after January 1, 2004 were disallowed by the IRS. By mitigating our risk, we believe we obtained assurance that it is highly probable that the financial benefit of tax credits claimed in 2004 will be sustained. Accordingly, in the first quarter 2004, we recognized the tax benefit of $13.5 million for synthetic tax credits related to the 2004 production of our South Carolina facility.

On April 15, 2004 we received a favorable private letter ruling. We believe receipt of the private letter ruling provides assurance that it is highly probable that the credits will be sustained. Therefore, we expect to recognize the tax benefit of approximately $36 million of the credits claimed in 2003 in our Consolidated Statements of Income during the quarter ended June 30, 2004, the quarter in which we received the private letter ruling.

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

Gains on Sale of Investments and Other Assets

During the first quarter of 2004, our other nonregulated businesses recognized $1.5 million of pre-tax gains on the sales of non-core assets as follows:

- $1.1 million pre-tax gain on an installment sale of real estate, and
- $0.4 million pre-tax gain on the sale of financial investments, as we continue to liquidate this operation.

Dividend Increase

In January 2004, we announced an increase in our quarterly dividend to 28.5 cents per share on our common stock payable April 1, 2004 to holders of record on March 10, 2004. This is equivalent to an annual rate of $1.14 per share. Previously, our quarterly dividend on our common stock was 26 cents per share, equivalent to an annual rate of $1.04 per share.

Planned Acquisition

On November 25, 2003, we announced an agreement with Rochester Gas and Electric (RG&E) to acquire the R.E. Ginna Nuclear Power Plant (Ginna) located north of Rochester, New York. Upon closing the acquisition of this 495 MW facility, we will own and operate three nuclear power stations. We expect to acquire this facility in mid-2004.

The estimated purchase price for the Ginna plant is approximately $400 million, excluding approximately $22 million for purchased nuclear fuel. RG&E will transfer approximately $202 million in decommissioning funds at the time of closing. We believe this transfer will be sufficient to meet the decommissioning requirements of the facility.

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

Results of Operations for the Quarter Ended March 31, 2004
Compared with the Same Period of 2003

In this section, we discuss our earnings and the factors affecting them. We begin with a general overview, then separately discuss earnings for our operating segments. Changes in other income, fixed charges, and income taxes are discussed, as necessary, in the aggregate for all segments in the *Consolidated Nonoperating Income and Expenses* section on page 43.

Overview

Results

Quarter Ended March 31,

	2004	2003
	(In millions, after tax)	
Merchant energy	**$ 39.5**	$ (20.5)
Regulated electric	**45.1**	50.2
Regulated gas	**27.8**	28.6
Other nonregulated	**0.1**	8.7
Income from Continuing Operations and Before Cumulative Effects of Changes in Accounting Principles	**112.5**	67.0
Loss from Discontinued Operations (see Notes)	**(46.3)**	
Cumulative Effects of Changes in Accounting Principles		(198.4)
Net Income (Loss)	**$ 66.2**	$ (131.4)
Special Items Included in Operations		
Gains on sale of investments and other assets	**$ 1.0**	$ 8.3

Quarter Ended March 31, 2004

Our total net income for the quarter ended March 31, 2004 increased $197.6 million, or $1.19 per share, compared to the same period of 2003 mostly because of the following:

We recorded a $266.1 million after-tax, or $1.61 per share, loss for the cumulative effect of adopting Emerging Issues Task Force (EITF) Issue 02-3, *Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities*. This was partially offset by a $67.7 million after-tax, or $0.41 per share, gain for the cumulative effect of adopting SFAS No. 143. These items had a combined negative impact during the first quarter of 2003.

We had higher earnings from our nuclear generating assets due to reduced outage days at our Calvert Cliffs nuclear power plant that began replacement of the steam generator for Unit 2 during the first quarter of 2003, partially offset by lower earnings at our Nine Mile Point facility primarily associated with our planned January 2004 outage.

We had higher earnings from our competitive supply activities mostly due to the growth in that business.

We had higher earnings due to the absence of losses of approximately $12 million associated with economic hedges that did not qualify for cash-flow hedge accounting treatment in 2003. We also had higher earnings due to the positive impact of approximately $6 million related to hedge ineffectiveness during the first quarter of 2004.

We had higher earnings of $13.5 million due to the High Desert Power Project that commenced operations in April 2003.

- We had higher earnings of $7.4 million primarily due to the recognition of tax credits associated with the 2004 production at our South Carolina synfuel facility.

These increases were partially offset by the following:

- We recorded a $46.3 million after-tax, or $0.27 per share, loss from discontinued operations.
- We had higher benefit and other inflationary costs.
- We had lower earnings from our regulated electric business mostly because of milder winter weather in the central Maryland region and higher operating expenses in the first quarter of 2004.
- We recognized a gain of $8.3 million after-tax, or $0.05 per share, related to non-core asset sales in the first quarter of 2003 that had a favorable impact in that period.

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

Merchant Energy Business

Background

Our merchant energy business is a competitive provider of energy solutions for large customers in North America. We discuss the impact of deregulation on our merchant energy business in the *Business Environment Electric Competition* section of our 2003 Annual Report on Form 10-K.

We record merchant energy revenues and expenses in our financial results in different periods depending upon which portion of our business they affect. We discuss our revenue recognition policies in the *Critical Accounting Policies* section on page 28 and in *Note 1* of our 2003 Annual Report on Form 10-K. We summarize our policies as follows:

We record revenues as they are earned and fuel and purchased energy costs as they are incurred for contracts and activities subject to accrual accounting, including certain load-serving activities.

Prior to the settlement of the forecasted transaction being hedged, we record changes in the fair value of contracts designated as cash-flow hedges in other comprehensive income to the extent that the hedges are effective. We record the effective portion of the changes in fair value of hedges in earnings in the period the settlement of the hedged transaction occurs. We record the ineffective portion of the changes in fair value of hedges, if any, in earnings in the period in which the change occurs.

We record changes in the fair value of contracts that are subject to mark-to-market accounting in revenues on a net basis in the period in which the change occurs.

Mark-to-market accounting requires us to make estimates and assumptions using judgment in determining the fair value of our contracts and in recording revenues from those contracts. We discuss the effects of mark-to-market accounting on our revenues in the *Competitive Supply Mark-to-Market Revenues* section on page 36. We discuss mark-to-market accounting and the accounting policies for the merchant energy business further in the *Critical Accounting Policies* section on page 28 and in *Note 1* of our 2003 Annual Report on Form 10-K.

Results

Quarter Ended March 31,

	2004	2003
	(In millions)	
Revenues	**$ 2,384.8**	$ 1,677.1
Fuel and purchased energy expenses	**(1,947.7)**	(1,390.1)
Operations and maintenance expenses	**(273.1)**	(213.3)
Depreciation and amortization	**(55.7)**	(50.9)
Accretion of asset retirement obligations	**(11.2)**	(10.7)
Taxes other than income taxes	**(21.8)**	(22.1)
Income (Loss) from Operations	**$ 75.3**	$ (10.0)
Income (Loss) from Continuing Operations and Before Cumulative Effects of Changes in Accounting Principles (after-tax)	**$ 39.5**	$ (20.5)
Loss from Discontinued Operations (after-tax)	**(46.3)**	
Cumulative Effects of Changes in Accounting Principles (after-tax)		(198.4)
Net Loss	**$ (6.8)**	$ (218.9)

Above amounts include intercompany transactions eliminated in our Consolidated Financial Statements. The Information by Operating Segment section within the Notes to Consolidated Financial Statements on page 14 provides a reconciliation of operating results by segment to our Consolidated Financial Statements.

Revenues and Fuel and Purchased Energy Expenses

Our merchant energy business manages our costs of procuring fuel and energy and revenues we realize from the sale of energy to our customers. The difference between revenues and fuel and purchased energy expenses is the primary driver of the profitability of our merchant energy business. Accordingly, we believe it is appropriate to discuss the operating results of our merchant energy business by analyzing the changes in the relationship between revenues and fuel and purchased energy expenses. In managing our portfolio, we occasionally terminate, restructure, or acquire contracts. Such transactions are within the normal course of managing our portfolio and may materially impact the timing of our recognition of revenues and fuel and purchased energy expenses.

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

Mid-Atlantic Fleet our fossil, nuclear, and hydroelectric generating facilities and load-serving activities in the PJM region for which the output is primarily used to serve BGE. This also includes active portfolio management of the generating assets and associated physical and financial arrangements.

Plants with Power Purchase Agreements our generating facilities with long-term power purchase agreements, including our Nine Mile Point Nuclear Station (Nine Mile Point), Oleander, University Park, and High Desert facilities.

Competitive Supply our wholesale marketing and risk management operation that provides energy products and services to distribution utilities and other wholesale customers. We also provide electric and gas energy services to retail commercial and industrial customers.

Other our investments in qualifying facilities and domestic power projects and our generation and consulting services.

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

Quarter Ended March 31,	*2004*	*2003*
	(Dollar amounts in millions)	
Revenues:		
Mid-Atlantic Fleet	**$ 431.3**	$ 375.7
Plants with Power Purchase Agreements	**133.8**	109.2
Competitive Supply	**1,799.5**	1,177.1
Other	**20.2**	15.1
Total	**$ 2,384.8**	$ 1,677.1
Fuel and purchased energy expenses:		
Mid-Atlantic Fleet	**$ (227.5)**	$ (205.5)
Plants with Power Purchase Agreements	**(10.5)**	(12.7)
Competitive Supply	**(1,709.7)**	(1,171.9)
Other		
Total	**$ (1,947.7)**	$ (1,390.1)

Revenues less fuel and purchased energy expenses:		**% of Total**		**% of Total**
Mid-Atlantic Fleet	**$ 203.8**	**47%**	$ 170.2	59%
Plants with Power Purchase Agreements	**123.3**	**28**	96.5	34
Competitive Supply	**89.8**	**20**	5.2	2
Other	**20.2**	**5**	15.1	5
Total	**$ 437.1**	**100%**	$ 287.0	100%

Mid-Atlantic Fleet

Quarter Ended March 31,	**2004**	**2003**

Quarter Ended March 31,		**2004**		**2003**
		(In millions)		
Revenues	**$**	**431.3**	$	375.7
Fuel and purchased energy expenses		**(227.5)**		(205.5)
Revenues less fuel and purchased energy	**$**	**203.8**	$	170.2

Revenues

BGE Standard Offer Service

The majority of Mid-Atlantic Fleet revenues arise from supplying BGE's standard offer service requirements. Revenues from supplying BGE's standard offer service requirements, including CTC and decommissioning revenues, were about the same in 2004 compared to 2003.

CTC revenues are impacted by the CTC rates our merchant energy business receives from BGE customers as well as the volumes delivered to BGE customers. The CTC rates decline over the transition period as previously discussed in the *Regulated Electric Competition Maryland* section on page 24.

During 2003, our merchant energy business provided the energy to meet the requirements of large commercial and industrial customers that had left BGE's standard offer service and elected BGE Home as their electric generation supplier. Revenues from BGE Home were $19.5 million in the first quarter of 2003, which had a positive impact in that period. As these customer contracts expired during 2003, any renewal was with our commercial and industrial retail marketing operation and the results are included in our Competitive Supply category.

Other Mid-Atlantic Fleet Revenues

Other merchant energy revenues in the PJM region increased $75.1 million in 2004 compared to 2003 mostly because of:

- $36.0 million related to load-serving transactions in New Jersey that began in mid-2003,
- $34.4 million related to higher prices for sales of our unhedged owned generation in excess of that used to serve BGE's standard offer service, including the higher generation at our Calvert Cliffs facility due to the absence of a planned outage during the first quarter of 2004, and
- higher sales of natural gas at higher prices.

Fuel and Purchased Energy Expenses

Our merchant energy business had higher fuel and purchased energy expenses in the Mid-Atlantic Fleet in 2004 compared to 2003 primarily due to higher generation at our plants and increased purchased energy and capacity expenses because of higher wholesale market prices.

Plants with Power Purchase Agreements

Quarter Ended March 31,

	2004	2003
	(In millions)	
Revenues	**$ 133.8**	$ 109.2
Fuel and purchased energy expenses	**(10.5)**	(12.7)
Revenues less fuel and purchased energy	**$ 123.3**	$ 96.5

The increase in revenues in 2004 compared to 2003 was primarily due to revenues of $38.5 million from the High Desert Power Project which commenced operations in the second quarter of 2003. This increase was offset in part by lower revenues of $14.3 million at our Nine Mile Point facility mostly because of lower availability of the plant due to our planned January outage during 2004 and higher power prices in the first quarter of 2003 that had a positive impact in that period.

Competitive Supply

Quarter Ended March 31,

	2004	2003
	(In millions)	
Accrual revenues	**$ 1,791.3**	$ 1,180.3
Mark-to-market revenues	**8.2**	(3.2)
Fuel and purchased energy expenses	**(1,709.7)**	(1,171.9)
Revenues less fuel and purchased energy	**$ 89.8**	$ 5.2

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

Accrual Revenues and Fuel and Purchased Energy Expenses

Our accrual revenues and fuel and purchased energy expenses increased in 2004 compared to 2003 mostly because of increased retail sales to commercial and industrial customers. This increase in sales of approximately $400 million is primarily due to high customer renewal rates, portfolio acquisitions during 2003, the acquisitions of Blackhawk and Kaztex in October 2003, and the positive impact of hedge ineffectiveness during the first quarter of 2004.

Additionally, our wholesale marketing and risk management operation had higher sales of approximately $200 million, primarily in Texas, New England, and Mid-West. The higher sales in the Texas and New England regions are primarily due to our growth in these regions. The higher sales in the Mid-West are primarily due to the portfolio acquisition from CMS Energy Corp., which occurred in the second quarter of 2003.

Mark-to-Market Revenues

Mark-to-market revenues include net gains and losses from origination and risk management activities for which we use the mark-to-market method of accounting. We discuss these activities and the mark-to-market method of accounting in more detail in the *Critical Accounting Policies* section on page 28.

As a result of the nature of our operations and the use of mark-to-market accounting for certain activities, mark-to-market revenues and earnings will fluctuate. We cannot predict these fluctuations, but the impact on our revenues and earnings could be material. We discuss our market risk in more detail in the *Market Risk* section on page 49. The primary factors that cause fluctuations in our mark-to-market revenues and earnings are:

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

Mark-to-market revenues were as follows:

Quarter Ended March 31,	**2004**	2003
	(In millions)	
Unrealized revenues		
Origination transactions	**$**	$ 14.2
Risk management		
Unrealized changes in fair value	**8.2**	(17.4)
Changes in valuation techniques		
Reclassification of settled contracts to realized	**(15.0)**	(44.0)
Total risk management	**(6.8)**	(61.4)
Total unrealized revenues	**(6.8)**	(47.2)
Realized revenues	**15.0**	44.0
Total mark-to-market revenues	**$ 8.2**	$ (3.2)

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

Origination gains represent the initial fair value recognized on these structured transactions. The recognition of origination gains is dependent on the existence of observable market data that validates the initial fair value of the contract. For the quarter ended March 31, 2004, we did not realize any origination gains.

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

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

Our mark-to-market revenues are affected by the portion of our activities that are subject to mark-to-market accounting. Beginning January 1, 2003, under EITF 02-3, we do not record non-derivative contracts at fair value. Further, to the extent that we are not able to observe quoted market prices or other current market transactions for derivative contract values determined using models, we record a reserve to adjust such contracts to result in zero gain or loss at inception. We remove the reserve and record such contracts at fair value when we obtain current market information for contracts with similar terms and counterparties.

Mark-to-market revenues increased $11.4 million during 2004 compared to 2003 mostly because of lower net losses from risk management activities compared to the prior year. The increase in risk management revenues is primarily due to mark-to-market losses on hedges that did not qualify for hedge accounting treatment during 2003 that had a negative impact in that period as discussed in more detail below, offset in part by higher origination gains in 2003.

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

In the first quarter of 2003, increasing forward prices shifted value between accrual load-serving positions and associated mark-to-market hedges producing a timing difference in the recognition of earnings on related transactions. As a result, we recorded a $19.8 million pre-tax loss on the mark-to-market hedges in the first quarter of 2003.

Mark-to-Market Energy Assets and Liabilities

Our mark-to-market energy assets and liabilities are comprised of derivative contracts and consisted of the following:

	March 31, 2004	**December 31, 2003**
	(In millions)	
Current Assets	**$ 569.5**	$ 488.3
Noncurrent Assets	**343.5**	261.9
Total Assets	**913.0**	750.2
Current Liabilities	**544.3**	474.6
Noncurrent Liabilities	**355.1**	258.0
Total Liabilities	**899.4**	732.6

	March 31, 2004	December 31, 2003
Net mark-to-market energy asset	**$ 13.6**	$ 17.6

The following are the primary sources of the change in net mark-to-market energy asset during the first quarter of 2004:

Change in Net Mark-to-Market Asset

		(In millions)
Fair value beginning of period		$ 17.6
Changes in fair value recorded as revenues		
Origination gains	$	
Unrealized changes in fair value	8.2	
Changes in valuation techniques		
Reclassification of settled contracts to realized	(15.0)	
Total changes in fair value recorded as revenues		(6.8)
Changes in value of exchange-listed futures and options		(16.6)
Net change in premiums on options		9.8
Other changes in fair value		9.6
Fair value at end of year		$ 13.6

Components of changes in the net mark-to-market energy asset that affected revenues include:

Origination gains representing the initial unrealized fair value at the time these contracts are executed to the extent permitted by applicable accounting rules.

Unrealized changes in fair value representing unrealized changes in commodity prices, the volatility of options on commodities, the time value of options, and other valuation adjustments.

Changes in valuation techniques representing improvements in estimation techniques, including modeling and other statistical enhancements used to value our portfolio to more accurately reflect the economic value of our contracts.

Reclassification of settled contracts to realized representing the portion of previously unrealized amounts settled during the period and recorded as realized revenues.

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

Changes in value of exchange-listed futures and options are adjustments to remove unrealized revenue from exchange-traded contracts that are included in risk management revenues. The fair value of these contracts is recorded in "Accounts receivable" rather than "Mark-to-market energy assets" in our Consolidated Balance Sheets because these amounts are settled through our margin account with a third-party broker.

Net changes in premiums on options reflects the accounting for premiums on options purchased as an increase in the net mark-to-market energy asset and premiums on options sold as a decrease in the net mark-to-market energy asset.

The settlement terms of the net mark-to-market energy asset and sources of fair value as of March 31, 2004 are as follows:

	Settlement Term							
	2004	**2005**	**2006**	**2007**	**2008**	**2009**	**Thereafter**	**Fair Value**
	(In millions)							
Prices provided by external sources (1)	$ 8.6	$ (9.1)	$ 71.5	$ 0.1	$	$	$	$ 71.1
Prices based on models	0.6	4.2	(60.9)	8.7	(3.5)	(2.7)	(3.9)	(57.5)
Total net mark-to-market energy asset	$ 9.2	$ (4.9)	$ 10.6	$ 8.8	$ (3.5)	$ (2.7)	$ (3.9)	$ 13.6

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

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

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

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

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

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

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

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

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

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

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

The fair values in the table represent expected future cash flows based on the level of forward prices and volatility factors as of March 31, 2004 and could change significantly as a result of future changes in these factors. Additionally, because the depth and liquidity of the power markets varies substantially between regions and time periods, the prices used to determine fair value could be affected significantly by the volume of transactions executed.

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

Other

Quarter Ended March 31,	**2004**	2003
	(In millions)	
Revenues	**$ 20.2**	$ 15.1

Our merchant energy business holds up to a 50% ownership interest in 25 operating domestic energy projects that consist of electric generation, fuel processing, or fuel handling facilities. Of these 25 projects, 18 are "qualifying facilities" that receive certain exemptions and pricing under the Public Utility Regulatory Policy Act of 1978 based on the facilities' energy source or the use of a cogeneration process. In addition, we own 100% of a geothermal generating facility in Hawaii we expect to sell in mid-2004. We discuss our geothermal facility in more detail in the *Notes to Consolidated Financial Statements* on page 12.

We believe the current market conditions for our equity-method investments that own geothermal, coal, hydroelectric, and fuel processing projects provide sufficient positive cash flows to recover our investments. We continuously monitor issues that potentially could impact future profitability of these investments, including environmental and legislative initiatives. We discuss certain risks and uncertainties in more detail in our *Forward Looking Statements* section on page 54. However, should future events cause these investments to become uneconomic, our investments in these projects could become impaired under the provisions of APB No. 18.

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

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

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

Operations and Maintenance Expenses

Our merchant energy business operations and maintenance expenses increased $59.8 million in 2004 compared to 2003 mostly due to the following:

- an increase at our wholesale marketing and risk management operation and our retail commercial and industrial operation of $21.8 million due to the growth of these activities, and
- an increase of $21.6 million at our Nine Mile Point facility, including $11.5 million related to the refueling outage of Unit 2,
- an increase of $4.8 million due to the operations of the High Desert Power Project that commenced operations in the second quarter of 2003.

Depreciation and Amortization Expense

Merchant energy depreciation and amortization expense increased $4.8 million in 2004 compared to 2003 mostly because of the High Desert Power Project, which was placed into service during the second quarter of 2003.

Regulated Electric Business

As discussed in the *Regulated Electric Competition Maryland* section on page 24, our regulated electric business was significantly impacted by the July 1, 2000 implementation of customer choice.

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

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

Results

Quarter Ended March 31,

	2004	2003
	(In millions)	
Revenues	**$ 484.4**	$ 486.3
Electricity purchased for resale expenses	**(240.4)**	(243.6)
Operations and maintenance expenses	**(65.1)**	(54.2)
Depreciation and amortization	**(47.8)**	(44.2)
Taxes other than income taxes	**(35.3)**	(35.3)
Income from Operations	**$ 95.8**	$ 109.0
Net Income	**$ 45.1**	$ 50.2

Above amounts include intercompany transactions eliminated in our Consolidated Financial Statements. The Information by Operating Segment section within the Notes to Consolidated Financial Statements on page 14 provides a reconciliation of operating results by segment to our Consolidated Financial Statements.

Net income from the regulated electric business decreased during the quarter ended March 31, 2004 compared to the same period of 2003 mostly because of the following:

- milder weather in the first quarter of 2004 compared to the same period of 2003,
- increased operations and maintenance expenses primarily due to higher uncollectible expenses, increased spending on reliability, and higher benefit and other inflationary costs, and
- increased depreciation and amortization expense.

These unfavorable results were partially offset by lower interest expense and an increased number of customers.

Electric Revenues

The changes in electric revenues in 2004 compared to 2003 were caused by:

Quarter Ended March 31,

	2004 vs. 2003

Quarter Ended March 31,

	2004 vs. 2003 *(In millions)*
Distribution sales volumes	$ 0.3
Standard offer service	0.1
Total change in electric revenues from electric system sales	0.4
Other	(2.3)
Total change in electric revenues	$ (1.9)

Distribution Sales Volumes

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

The percentage changes in our distribution sales volumes, by type of customer, in 2004 compared to 2003 were:

Quarter Ended March 31,

	2004 vs. 2003
Residential	(0.3)%
Commercial	(1.6)
Industrial	(0.7)

Standard Offer Service

BGE provides standard offer service for customers that do not select an alternative generation supplier as discussed in the *Regulated Electric Competition Maryland* section on page 24.

Electricity Purchased for Resale Expenses

Electricity purchased for resale expenses include the cost of electricity purchased for resale to our standard offer service customers. These costs do not include the cost of electricity purchased by delivery service only customers.

Electric Operations and Maintenance Expenses

Regulated electric operations and maintenance expenses increased $10.9 million in 2004 compared to 2003 mostly due to higher uncollectible expenses, increased spending on reliability, and higher benefit and other inflationary costs.

Electric Depreciation and Amortization Expenses

Regulated electric depreciation and amortization expenses increased $3.6 million in 2004 compared to 2003 mostly because of increased depreciation expense associated with more property being placed in service and accelerated amortization expense associated with the planned replacement of information technology assets.

Regulated Gas Business

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

Results

Quarter Ended March 31,

	2004	2003
	(In millions)	
Revenues	**$ 319.5**	$ 303.5
Gas purchased for resale expenses	**(216.0)**	(203.1)
Operations and maintenance expenses	**(27.5)**	(23.2)
Depreciation and amortization	**(12.1)**	(11.7)
Taxes other than income taxes	**(9.9)**	(9.9)
Income from operations	**$ 54.0**	$ 55.6
Net Income	**$ 27.8**	$ 28.6

Above amounts include intercompany transactions eliminated in our Consolidated Financial Statements. The Information by Operating Segment section within the Notes to Consolidated Financial Statements on page 14 provides a reconciliation of operating results by segment to our Consolidated Financial Statements.

Gas Revenues

The changes in gas revenues in 2004 compared to 2003 were caused by:

Quarter Ended March 31,

	2004 vs. 2003
	(In millions)
Distribution sales volumes	$ 1.2
Base rates	(0.1)
Weather normalization	0.8
Gas cost adjustments	31.1
Total change in gas revenues from gas system sales	33.0
Off-system sales	(17.2)
Other	0.2
Total change in gas revenues	$ 16.0

<u>*Distribution Sales Volumes*</u>

The percentage changes in our distribution sales volumes, by type of customer, in 2004 compared to 2003 were:

Quarter Ended March 31,

	2004 vs. 2003
Residential	0.2%
Commercial	10.1

Quarter Ended March 31,	**2004 vs. 2003**
Industrial	(16.7)

We distributed about the same amount of gas to residential customers in 2004 compared to 2003. We distributed more gas to commercial customers mostly due to increased usage per customer partially offset by milder weather. We distributed less gas to industrial customers mostly due to decreased usage.

Weather Normalization

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

Gas Cost Adjustments

We charge our gas customers for the natural gas they purchase from us using gas cost adjustment clauses set by the Maryland PSC as described in *Note 1* of our 2003 Annual Report on Form 10-K. However, under market-based rates, our actual cost of gas is compared to a market index (a measure of the market price of gas in a given period). The difference between our actual cost and the market index is shared equally between shareholders and customers.

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

Gas cost adjustment revenues increased in 2004 compared to 2003 because we sold gas at a higher price partially offset by less gas sold.

Off-System Gas Sales

Off-system gas sales are low-margin direct sales of gas to wholesale suppliers of natural gas outside our service territory. Off-system gas sales, which occur after we have satisfied our customers' demand, are not subject to gas cost adjustments. The Maryland PSC approved an arrangement for part of the margin from off-system sales to benefit customers (through reduced costs) and the remainder to be retained by BGE (which benefits shareholders). Changes in off-system sales do not significantly impact earnings.

Revenues from off-system gas sales decreased in 2004 compared to 2003 mostly because we sold less gas.

Gas Purchased For Resale Expenses

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

Gas costs increased in 2004 compared to 2003 because we purchased gas for system sales at a higher price.

Gas Operations and Maintenance Expenses

Regulated gas operations and maintenance expenses increased in 2004 compared to 2003 mostly due to higher uncollectible expenses and higher benefit and other inflationary costs.

Other Nonregulated Businesses

Results

Quarter Ended March 31,

	2004	2003
	(In millions)	
Revenues	**$ 103.8**	$ 155.6
Operating expenses	**(86.8)**	(143.0)
Depreciation and amortization	**(7.4)**	(4.3)
Taxes other than income taxes	**(0.5)**	(1.0)
Net gain on sales of investments and other assets	**1.5**	13.7
Income from Operations	**$ 10.6**	$ 21.0
Net Income	**$ 0.1**	$ 8.7
Special Items Included in Operations (after-tax)		
Gains on sale of investments and other assets	**$ 1.0**	$ 8.3

Above amounts include intercompany transactions eliminated in our Consolidated Financial Statements. The Information by Operating Segment section within the Notes to Consolidated Financial Statements on page 14 provides a reconciliation of operating results by segment to our Consolidated Financial Statements.

During the quarter ended March 31, 2004, net income from our other nonregulated businesses decreased compared to the same period of 2003 mostly because we recognized $13.7 million pre-tax, or $8.3 million after-tax, gains on the sale of non-core assets in 2003 as follows:

a $7.2 million pre-tax gain on the sale of an oil tanker to the U.S. Navy,

a $5.3 million pre-tax gain on the favorable settlement of a contingent obligation we had previously reserved relating to the sale of our Guatemalan power plant operation in the fourth quarter of 2001, and

a $1.2 million pre-tax gain on an installment sale of a parcel of real estate.

As previously discussed in our 2003 Annual Report on Form 10-K, we decided to sell certain non-core assets and accelerate the exit strategies on other assets that we will continue to hold and own over the next several years. While our intent is to dispose of these assets, market conditions and other events beyond our control may affect the actual sale of these assets. In addition, a future decline in the fair value of these assets could result in additional losses.

Consolidated Nonoperating Income and Expenses

Fixed Charges

During the quarter ended March 31, 2004, total fixed charges increased $4.3 million compared to the same period of 2003 mostly due to a higher level of debt outstanding, including the issuance of $550 million of debt in June 2003 that was used to refinance the High Desert Power Project lease.

During the quarter ended March 31, 2004, total fixed charges at BGE decreased $4.4 million compared to the same period of 2003 mostly because of a lower level of debt outstanding.

Income Taxes

During the quarter ended March 31, 2004, our income taxes increased $6.2 million compared to the same period of 2003 mostly because of an increase in taxable income partially offset by the recognition of synthetic fuel tax credits claimed in 2004 related to our investment in a South Carolina synthetic fuel facility, which reduced our effective tax rate. We discuss our synthetic fuel tax credits in more detail in the *Events of 2004 Synthetic Fuel Tax Credits* section on page 31.

During the quarter ended March 31, 2004, income taxes at BGE decreased $3.9 million compared to the same period of 2003 mostly because of lower taxable income.

Financial Condition

Cash Flows

The following table summarizes our cash flows for the first quarter of 2004 and 2003, excluding the impact of changes in intercompany balances.

	2004 Segment Cash Flows			Consolidated Cash Flows	
	Three Months Ended March 31, 2004			Three Months Ended March 31,	
	Merchant	Regulated	Other	2004	2003
	(In millions)				
Operating Activities					
Net (loss) income	$ (6.8)	$ 72.9	$ 0.1	$ 66.2	$ (131.4)
Non-cash adjustments to net income	165.9	73.3	6.7	245.9	347.3
Changes in working capital	15.3	51.0	(9.1)	57.2	96.2
Pension and postemployment benefits*				(36.9)	(98.1)
Other	(19.1)	7.5	10.8	(0.8)	28.8
Net cash provided by operating activities	155.3	204.7	8.5	331.6	242.8
Investing activities					
Investments in property, plant and equipment	(111.2)	(52.1)	(8.0)	(171.3)	(145.2)
Contributions to nuclear decommissioning trust funds	(8.8)			(8.8)	(4.4)
Sale of investments and other assets		4.9	1.8	6.7	89.8
Other investments	(5.5)		(1.9)	(7.4)	(21.9)
Net cash used in investing activities	(125.5)	(47.2)	(8.1)	(180.8)	(81.7)
Cash flows from operating activities less cash flows from investing activities	$ 29.8	$ 157.5	$ 0.4	150.8	161.1
Financing Activities					
Net repayment of debt*				(4.5)	(133.0)
Proceeds from issuance of common stock*				15.2	10.1
Common stock dividends paid*				(43.5)	(39.6)
Other*				1.5	(1.4)
Net cash used in financing activities*				(31.3)	(163.9)
Net Increase (Decrease) in Cash and Cash Equivalents*				$ 119.5	$ (2.8)

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

Cash Flows from Operating Activities

Cash provided by operating activities was $331.6 million in 2004 compared to $242.8 million in 2003. Net income was $197.6 million higher in 2004 compared to 2003. This was partially offset by a decrease in non-cash adjustments to net income of $101.4 million in 2004 compared to 2003. The net decrease in non-cash adjustments to net income was primarily due to cumulative effects of changes in accounting principles of $198.4 million as a result of the adoption of SFAS No. 143 and EITF 02-3 in 2003, which had the effect of reducing net income but were non-cash transactions. This decrease in non-cash adjustments to net income was partially offset by the following increases:

- a loss from discontinued operations of $46.3 million in 2004;
- an increase in deferred fuel costs of $28.9 million in 2004 compared to 2003; and
- an increase in depreciation and amortization of $17.2 million in 2004 compared to 2003.

Changes in working capital had a positive impact of $57.2 million on cash flow from operations in 2004 compared to $96.2 million in 2003. The net decrease of $39.0 million was primarily due to a $32 million federal tax refund in 2003 and a federal tax payment in 2004. This decrease in working capital was partially offset by a source of cash resulting from a larger decrease in BGE natural gas fuel stocks in 2004 compared to 2003. Pension and postemployment benefits were a use of cash of $39.6 million in 2004 compared to $98.1 million in 2003. This primarily reflects a $60 million lower contribution to the pension plan in 2004 compared to 2003.

Cash Flows from Investing Activities

Cash used in investing activities was $180.8 million in 2004 compared to $81.7 million in 2003. The increase in cash used in 2004 compared to 2003 was primarily due to a decrease in cash proceeds from the sales of investments and other assets and an increase in investments in property, plant and equipment.

Cash Flows from Financing Activities

Cash used in financing activities was $31.3 million in 2004 compared to $163.9 million in 2003. The decrease in 2004 compared to 2003 was mostly due to a lower repayment of debt in 2004 compared to 2003.

Security Ratings

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

The factors that credit rating agencies consider in establishing Constellation Energy's and BGE's credit ratings include, but are not limited to, cash flows, liquidity, and the amount of debt as a component of total capitalization. In March 2004, Standard & Poors rating group reduced Constellation Energy's and BGE's corporate credit rating from A- to BBB+ and reduced certain other ratings as noted in the table below. All Constellation Energy and BGE credit ratings have stable outlooks. At the date of this report, our credit ratings were as follows:

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

** In March 2004, Standard & Poors Rating Group reduced the rating one level to this current rating.*

Available Sources of Funding

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

Constellation Energy

In addition to our cash balance, we have a commercial paper program under which we can issue short-term notes to fund our subsidiaries. At March 31, 2004, we had approximately $1.5 billion of credit under three facilities. These facilities include:

- a $447.5 million 364-day revolving credit facility that expires in June 2004,
- a $447.5 million three-year revolving credit facility that expires in June 2006, and

- a $640.0 million revolving credit facility that expires in June 2005.

We use these facilities to allow the issuance of commercial paper. In addition, we use the multi-year facilities to allow for the issuance of letters of credit.

These revolving credit facilities allow the issuance of letters of credit up to approximately $1.1 billion. At March 31, 2004, letters of credit that totaled $730.5 million were issued under all of our facilities, which results in approximately $805 million of unused credit facilities.

BGE

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

Other Nonregulated Businesses

BGE Home Products & Services' program to sell up to $50 million of receivables was not extended beyond its March 2004 expiration date. We expect to fully liquidate this receivables program by the end of 2004.

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

Capital Resources

Our estimated annual amounts for the years 2004 and 2005 are shown in the table below.

We will continue to have cash requirements for:

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

Capital requirements for 2004 and 2005 include estimates of spending for existing and anticipated projects. We continuously review and modify those estimates. Actual requirements may vary from the estimates included in the table below because of a number of factors including:

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

Our estimates are also subject to additional factors. Please see the *Forward Looking Statements* section on page 54.

Calendar Year Estimates

	2004	2005
	(In millions)	
Nonregulated Capital Requirements:		
Merchant energy		
Generation plants	$ 170	$ 155
Nuclear fuel	115	65
Portfolio acquisitions	60	60
Technology/other	105	85
Total merchant energy capital requirements (A)	450	365
Other nonregulated capital requirements	40	50
Total nonregulated capital requirements	490	415
Utility Capital Requirements:		
Regulated electric	220	250
Regulated gas	60	55

Calendar Year Estimates

	2004	2005
Total utility capital requirements	280	305
Total capital requirements	$ 770	$ 720

(A) Excludes approximately $25 million of 2004 and approximately $50 million of 2005 capital requirements, including nuclear fuel for Ginna. We discuss our planned acquisition of Ginna in the *Events of 2004* section on page 32.

Capital Requirements

Merchant Energy Business

Our merchant energy business' capital requirements consist of its continuing requirements, including construction expenditures for improvements to generating plants, nuclear fuel costs, costs of complying with the Environmental Protection Agency (EPA), Maryland, and Pennsylvania nitrogen oxides (NOx) emissions regulations, and enhancements to our information technology infrastructure. We discuss the NOx regulations and timing of expenditures in *Note 12* of our 2003 Annual Report on Form 10-K.

Regulated Electric and Gas

Regulated electric and gas construction expenditures primarily include new business construction needs and improvements to existing facilities, including projects to improve reliability.

Funding for Capital Requirements

Merchant Energy Business

Funding for the expansion of our merchant energy business is expected from internally generated funds. We also have available sources from commercial paper issuances, issuances of long-term debt and equity, leases, and other financing activities.

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

We expect to fund acquisitions, including Ginna, with an overall goal of maintaining a strong investment grade credit profile. Funding of this acquisition is expected to occur in mid-2004.

Regulated Electirc and Gas

Funding for utility capital expenditures is expected from internally generated funds. During 2004, we expect our regulated businesses to generate sufficient cash flows from operations to meet BGE's operating requirements. If necessary, additional funding may be obtained from commercial paper issuances, available capacity under credit facilities, the issuance of long-term debt, trust securities, or preference stock, and/or from time to time equity contributions from Constellation Energy. BGE also participates in a cash pool administered by Constellation Energy as discussed in the *Notes to Consolidated Financial Statements* section on page 21.

Other Nonregulated Businesses

Funding for our other nonregulated businesses is expected from internally generated funds, commercial paper issuances, issuances of long-term debt of Constellation Energy, sales of securities and assets, and/or from time to time, equity contributions from Constellation Energy.

Our ability to sell or liquidate securities and non-core assets will depend on market conditions, and we cannot give assurances that these sales or liquidations could be made.

Contractual Payment Obligations and Committed Amounts

Our total contractual payment obligations as of March 31, 2004 are shown in the following table:

	Payments				
	2004	**2005-2006**	**2007-2008**	**There-after**	**Total**
			(In millions)		
Contractual Payment Obligations					
Long-term debt:[1]					
Nonregulated					
Principal	$ 10.2	$ 343.9	$ 636.0	$ 2,744.8	$ 3,734.9
Interest	175.8	433.8	364.1	1,741.7	2,715.4
Total	186.0	777.7	1,000.1	4,486.5	6,450.3
BGE					
Principal	151.4	482.7	418.5	600.8	1,653.4
Interest	66.4	169.4	96.7	824.0	1,156.5
Total	217.8	652.1	515.2	1,424.8	2,809.9
BGE preference stock				190.0	190.0
Operating leases	17.3	40.9	27.1	121.5	206.8
Purchase obligations:[2]					
Purchased capacity and energy[3]	990.2	1,118.3	274.9	207.2	2,590.6
Fuel and transportation[4]	499.0	509.5	116.2	52.8	1,177.5
Other	61.5	67.0	34.0	247.8	410.3
Other noncurrent liabilities:					
Postretirement and postemployment benefits[5]	38.0	87.0	99.5	139.7	364.2
Other	5.7	5.9			11.6
Total contractual payment obligations	$ 2,015.5	$ 3,258.4	$ 2,067.0	$ 6,870.3	$ 14,211.2

1

Amounts in long-term debt reflect the original maturity date. Investors may require us to repay $327.0 million early through put options and remarketing features.

2

Contracts to purchase goods or services that specify all significant terms. Amounts related to certain purchase obligations are based on future purchase expectations which may differ from actual purchases.

3

Our contractual obligations for purchased capacity and energy are shown on a gross basis for certain transactions, including both the fixed payment portions of tolling contracts and estimated variable payments under unit-contingent power purchase agreements. We have recorded $30.3 million of liabilities related to purchased capacity and energy obligations at March 31, 2004 in our Consolidated Balance Sheets.

4

4 We have recorded liabilities of $64.5 million related to fuel and transportation obligations at March 31, 2004 in our Consolidated Balance Sheets.

5

Amounts related to postretirement and postemployment benefits are for unfunded plans and reflect present value amounts consistent with the determination of the related liabilities recorded on the Consolidated Balance Sheets.

The table on the next page presents our contingent obligations. Our contingent obligations increased $1.2 billion during the first quarter of 2004, primarily due to the issuance of additional guarantees and letters of credit by the parent company for subsidiary obligations to third parties in support of the growth of our merchant energy business. These amounts do not represent incremental consolidated Constellation Energy obligations; rather they primarily represent parental guarantees of certain subsidiary obligations to third parties. Our calculation of the fair value of subsidiary obligations covered by the $4,592.0 million of parent company guarantees was $1,125.8 million at March 31, 2004. Accordingly, if the parent company was required to fund subsidiary obligations, the total amount at current market prices is $1,125.8 million.

	Expiration				
	2004	2005-2006	2007-2008	There-after	Total
			(In millions)		
Contingent Obligations					
Letters of credit	$ 697.7	$ 32.8	$	$	$ 730.5
Guarantees competitive supply[1]	3,306.9	495.0	292.0	498.1	4,592.0
Other guarantees, net[2]	9.9	11.6		838.1	859.6
Total contingent obligations	$ 4,014.5	$ 539.4	$ 292.0	$ 1,336.2	$ 6,182.1

1 *While the face amount of these guarantees is $4,592.0 million, we do not expect to fund the full amount. Our calculation of the fair value of obligations covered by these guarantees was $1,125.8 million at March 31, 2004.*

2 *Other guarantees in the above table are shown net of liabilities of $25.6 million recorded at March 31, 2004 in our Consolidated Balance Sheets.*

Liquidity Provisions

We have certain agreements that contain provisions that would require additional collateral upon significant credit rating decreases in the Senior Unsecured Debt of Constellation Energy. Decreases in Constellation Energy's credit ratings would not trigger an early payment on any of our credit facilities.

Under certain counterparty contracts related to our wholesale marketing and risk management operation, we are obligated to post collateral if Constellation Energy's senior, unsecured credit ratings decline below established contractual levels. As a result of the ratings action taken by Standard & Poors rating agency in March 2004, we posted approximately $40 million in additional collateral to support our wholesale marketing and risk management operational requirements. We discuss the Standard & Poors ratings action in more detail in the *Financial Condition* section on page 45.

Based on contractual provisions, we estimate that we would have additional collateral obligations based on downgrades to the following credit ratings for our Senior Unsecured Debt:

Credit Ratings Downgraded	Level Below Current Rating	Incremental Obligations	Cumulative Obligations
		(In millions)	
BBB-/Baa3	1	$ 127	$ 127
Below investment grade	2	669	796

At March 31, 2004, we had approximately $1.0 billion of unused credit facilities and $840.8 million of cash available to meet these potential requirements. However, based on market conditions and contractual obligations at the time of such a downgrade, we could be required to post collateral in an amount that could exceed the amounts specified above, and which could be material.

We consistently review our liquidity needs to ensure that we have adequate facilities available to meet these requirements. This includes having liquidity available to meet margin requirements for our wholesale marketing and risk management operation.

In many cases, customers of our wholesale marketing and risk management operation rely on the creditworthiness of Constellation Energy. A decline below investment grade by Constellation Energy would negatively impact the business prospects of that operation. The credit facilities of Constellation Energy and BGE have limited material adverse change clauses that only consider a material change in financial condition and are not directly affected by decreases in credit ratings. If these clauses are violated, the lending institutions can decline making new advances or issuing new letters of credit, but cannot accelerate existing amounts outstanding. The long-term debt indentures of Constellation Energy and BGE do not contain material adverse change clauses or financial covenants.

Certain credit facilities of Constellation Energy contain a provision requiring Constellation Energy to maintain a ratio of debt to capitalization equal to or less than 65%. At March 31, 2004, the debt to capitalization ratios as defined in the credit agreements were no greater than 55%. Certain credit facilities of BGE contain provisions requiring BGE to maintain a ratio of debt to capitalization equal to or less than 65%. At March 31, 2004, the debt to capitalization ratio for BGE as defined in these credit agreements was 49%. At March 31, 2004, no amount is outstanding under these facilities.

Failure by Constellation Energy, or BGE, to comply with these covenants could result in the maturity of the debt outstanding under these facilities being accelerated. The credit facilities of Constellation Energy contain usual and customary cross-default provisions that apply to defaults on debt by Constellation Energy and certain subsidiaries over a specified threshold. Certain BGE credit facilities also contain usual and customary cross-default provisions that apply to defaults on debt by BGE over a specified threshold. The indentures pursuant to which BGE has issued and outstanding mortgage bonds and subordinated debentures provide that a default under any debt instrument issued under the relevant indenture may cause a default of all debt outstanding under such indenture.

Constellation Energy also provides credit support to Calvert Cliffs and Nine Mile Point to ensure these plants have funds to meet expenses and obligations to safely operate and maintain the plants.

Market Risk

Commodity Risk

During the first quarter of 2004, the energy markets continued to be highly volatile with significant increases in fuel prices, primarily natural gas and coal, and power prices as well as the continuation of reduced liquidity in the marketplace.

We measure the sensitivity of our wholesale marketing and risk management mark-to-market energy contracts to potential changes in market prices using value at risk. Value at risk represents the potential pre-tax loss in the fair value of our wholesale marketing and risk management mark-to-market energy assets and liabilities over one and ten-day holding periods. We discuss value at risk in more detail in the *Market Risk* section of our 2003 Annual Report on Form 10-K. The table below is the value at risk associated with our wholesale marketing and risk management operation's mark-to-market energy assets and liabilities, including both trading and non-trading activities.

	Quarter Ended March 31, 2004
	(In millions)
99% Confidence Level, One-Day Holding Period	
Average	$ 4.2
High	6.3
95% Confidence Level, One-Day Holding Period	
Average	3.2
High	4.8
95% Confidence Level, Ten-Day Holding Period	
Average	10.2
High	15.1

The following table details our value at risk for the trading portion of our wholesale marketing and risk management mark-to-market energy assets and liabilities over a one-day holding period at a 99% confidence level for the first quarter of 2004:

	Quarter Ended March 31, 2004
	(In millions)
Average	$ 2.3
High	5.3

Due to the inherent limitations of statistical measures such as value at risk and the seasonality of changes in market prices, the value at risk calculation may not reflect the full extent of our commodity price risk exposure. Additionally, actual changes in the value of options may differ from the value at risk calculated using a linear approximation inherent in our calculation method.

As a result, actual changes in the fair value of mark-to-market energy assets and liabilities could differ from the calculated value at risk, and such changes could have a material impact on our financial results.

Wholesale Credit Risk

We continue to actively manage the credit portfolio of our wholesale marketing and risk management operation to attempt to reduce the impact of the general decline in the overall credit quality of the energy industry and the impact of a potential counterparty default. As of March 31, 2004 and December 31, 2003, the credit portfolio of our wholesale marketing and risk management operation had the following public credit ratings*:*

	March 31, 2004	December 31, 2003

	March 31, 2004	December 31, 2003
Rating		
Investment Grade[1]	**69**%	75%
Non-Investment Grade	**10**	4
Not Rated	**21**	21

1

Includes counterparties with an investment grade rating by at least one of the major credit rating agencies. If split rating exists, the lower rating is used.

In addition to the credit ratings provided by the major credit rating agencies, we utilize internal credit ratings to evaluate the creditworthiness of our wholesale customers, including those companies that do not have public credit ratings. The "Not Rated" category in the table above includes counterparties that do not have public credit ratings and include governmental entities, municipalities, cooperatives, power pools, and other load-serving entities, and marketers for which we determine creditworthiness based on internal credit ratings.

The following table provides the breakdown of the credit quality of our wholesale credit portfolio based on our internal credit ratings.

	March 31, 2004	December 31, 2003
Investment Grade Equivalent	**81**%	91%
Non-Investment Grade	**19**	9

Compared to December 31, 2003, we have experienced deterioration in the credit quality of our wholesale marketing and risk management portfolio measured using both public credit ratings and our internal credit ratings. The decline in investment grade equivalent counterparties is primarily due to increased exposure to lower credit quality fuel and power supply counterparties. A portion of our wholesale credit risk is related to transactions that are recorded in our Consolidated Balance Sheets. These transactions primarily consist of open positions from our wholesale marketing and risk management operation that are accounted for using mark-to-market accounting, as well as amounts owed by wholesale counterparties for transactions that settled but have not yet been paid. The following table highlights the credit quality and exposures related to these activities at March 31, 2004:

Rating	Total Exposure Before Credit Collateral	Credit Collateral	Net Exposure	Number of Counterparties Greater than 10% of Net Exposure	Net Exposure of Counterparties Greater than 10% of Net Exposure
	(Dollars in millions)				
Investment grade	$ 667	$ 47	$ 620	1	$ 90
Split rating	11		11		
Non-investment grade	165	141	24		
Internally rated investment grade	153	89	64		
Internally rated non-investment grade	37	10	27		
Total	$ 1,033	$ 287	$ 746	1	$ 90

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

Additionally, if a counterparty were to default and we were to liquidate all contracts with that entity, our credit loss would include the loss in value of mark-to-market contracts, the amount owed for settled transactions, and additional payments, if any, we would have to make to settle unrealized losses on accrual contracts.

We continue to examine plans to achieve our strategies and to further strengthen our balance sheet and enhance our liquidity. We discuss our liquidity in the *Financial Condition* section on page 48.

Interest Rate Risk, Retail Credit Risk, and Equity Price Risk

We discuss our exposure to interest rate risk, retail credit risk, and equity price risk in the *Market Risk* section of our 2003 Annual Report on Form 10-K.

Other Matters

Environmental Matters

We are subject to federal, state, and local laws and regulations that work to improve or maintain the quality of the environment. If certain substances were disposed of, or released at any of our properties, whether currently operating or not, these laws and regulations require us to remove or remedy the effect on the environment. This includes Environmental Protection Agency Superfund sites.

You will find details of our environmental matters in the *Environmental Matters* section of the *Notes to Consolidated Financial Statements* beginning on page 17 and in our 2003 Annual Report on Form 10-K in *Item 1. Business Environmental Matters.* These details include financial information. Some of the information is about costs that may be material.

Accounting Standards Adopted

We discuss recently adopted accounting standards in the *Accounting Standards Adopted* section of the *Notes to Consolidated Financial Statements* beginning on page 20.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

We discuss the following information related to our market risk:

SFAS No. 133 hedging activities section in the *Notes to Consolidated Financial Statements* beginning on page 19,

activities of our wholesale marketing and risk management operation in the *Merchant Energy Business* section of *Management's Discussion and Analysis* beginning on page 34,

evaluation of commodity and wholesale credit risk in the *Market Risk* section of *Management's Discussion and Analysis* beginning on page 49, and

changes to our business environment in the *Business Environment* section of *Management's Discussion and Analysis* beginning on page 24.

Item 4. Controls and Procedures

A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within Constellation Energy or BGE have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple error or mistake. Additionally, controls can be circumvented by the individual acts of some persons or by collusion of two or more people.

The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no absolute assurance that any design will succeed in achieving its stated goals under all potential future conditions; over time, controls may become inadequate because of changes in conditions, or the degree of compliance with the policies or procedures may deteriorate. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected.

The principal executive officers and principal financial officer of both Constellation Energy and BGE have evaluated the effectiveness of the disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")) as of the end of the fiscal quarter covered by this quarterly report (the "Evaluation Date"). Based on such evaluation, such officers have concluded that, as of the Evaluation Date, Constellation Energy's and BGE's disclosure controls and procedures are effective, in that they provide reasonable assurance that such officers are alerted on a timely basis to material information relating to Constellation Energy and BGE that is required to be included in Constellation Energy's and BGE's periodic filings under the Exchange Act.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

California

Baldwin Associates, Inc. v. Gray Davis, Governor of California and 22 other defendants (including Constellation Power Development, Inc., a subsidiary of Constellation Power, Inc.) This class action lawsuit was filed on October 5, 2001 in the Superior Court, County of San Francisco. The action seeks damages of $43 billion, recession and reformation of approximately 38 long-term power purchase contracts, and an injunction against improper spending by the state of California.

Constellation Power Development, Inc. is named as a defendant but has never been served with process in this case and does not have a power purchase agreement with the State of California. However, our High Desert Power Project does have a power purchase agreement with the California Department of Water Resources. The court issued an order to the plaintiff asking that he show cause why he had not yet served any of the defendants with process. A hearing is scheduled on August 23, 2004 on the court's show cause order.

James M. Millar v. Allegheny Energy Supply, Constellation Power Source, Inc., High Desert Power Project, LLC, et al On December 19, 2003, plaintiffs filed an amended complaint in Superior Court of California, County of San Francisco, naming for the first time, Constellation Power Source, Inc. (CPS) and High Desert Power Project, LLC (High Desert), two of our subsidiaries, as additional defendants. The complaint is a putative class action on behalf of California electricity consumers and alleges that the defendant power suppliers, including CPS and High Desert, violated California's Unfair Competition Law in connection with certain long-term power contracts that the defendants negotiated with the California Department of Water Resources in 2001 and 2002. Notwithstanding the amended long-term power contracts and the releases and settlement agreements negotiated at the time of such amendments, the plaintiff seeks to have the Court certify the case as a class action and to order the repayment of any monies that were acquired by the defendants under the long-term contracts or the amended long-term contracts by means of unfair competition in violation of California law. The amended complaint was removed to federal court by one of the defendants and a motion to remand the case back to the state court is pending before the federal court. We believe that we have meritorious defenses to this action and intend to defend against it vigorously. However, we can not predict the timing, or outcome, of this case, or its possible effect on our results.

NewEnergy

Constellation NewEnergy, Inc. v. PowerWeb Technology, Inc. Prior to our acquisition, NewEnergy filed a complaint on May 9, 2002 in the U.S. District Court of Eastern Pennsylvania seeking approximately $100,000 in direct damages relating to a contract previously entered into with PowerWeb. PowerWeb Technology has counter-claimed seeking $100 million in damages against NewEnergy alleging a breach of a non-disclosure agreement by misappropriation of trade secrets and tortious interference claims. Discovery is ongoing in the matter. We cannot predict the timing, or outcome, of the action or its possible effect on our financial results. However, based on the information available to Constellation Energy at this time, we believe NewEnergy has meritorious defenses to the PowerWeb Technology counterclaim.

Mercury Poisoning

Beginning in September 2002, BGE, Constellation Energy, and several other defendants have been involved in numerous actions filed in the Circuit Court for Baltimore City, Maryland alleging mercury poisoning from several sources, including coal plants formerly owned by BGE. The plants are now owned by a subsidiary of Constellation Energy. In addition to BGE and Constellation Energy, approximately 11 other defendants, consisting of pharmaceutical companies, manufacturers of vaccines and manufacturers of Thimerosal have been sued. Approximately 50 cases have been filed to date, with each case seeking $90 million in damages from the group of defendants.

In a ruling applicable to all but several of the cases, the Circuit Court for Baltimore City dismissed with prejudice all claims against BGE and Constellation Energy and entered into a stay of the proceedings as they relate to other defendants. The several cases that were not dismissed were filed subsequent to the ruling by the Circuit Court. Plaintiffs may attempt to pursue appeals of the rulings in favor of BGE and Constellation Energy once the cases are finally concluded as to all defendants. We believe that we have meritorious defenses and intend to defend the actions vigorously. However, we cannot predict the timing, or outcome, of these cases, or their possible effect on our, or BGE's, financial results.

Employment Discrimination

Miller, et. al v. Baltimore Gas and Electric Company, et al. This action was filed on September 20, 2000 in the U.S. District Court for the District of Maryland. Besides BGE, Constellation Energy Group, Constellation Nuclear, and Calvert Cliffs Nuclear Power Plant are also named defendants. The action seeks class certification for approximately 150 past and present employees and alleges racial discrimination at Calvert Cliffs Nuclear Power Plant.

The amount of damages is unspecified, however the plaintiffs seek back and front pay, along with compensatory and punitive damages. The Court scheduled a briefing process for the motion to certify the case as a class action suit. The briefing process concluded and oral argument on the class certification motion was held on April 16, 2004, and the parties are awaiting the court's decision. We do not believe class certification is appropriate and we further believe that we have meritorious defenses to the underlying claims and intend to defend the action vigorously. However, we cannot predict the timing, or outcome, of the action or its possible effect on our, or BGE's, financial results.

Asbestos

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

The first type is direct claims by individuals exposed to asbestos. BGE is involved in these claims with approximately 70 other defendants. Approximately 560 individuals that were never employees of BGE each claim $6 million in damages ($2 million compensatory and $4 million punitive). These claims are currently pending in state courts in Maryland and Pennsylvania. BGE does not know the specific facts necessary to estimate its potential liability for these claims. The specific facts BGE does not know include:

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

To date, 279 asbestos cases were dismissed or resolved for amounts that were not significant. Approximately 51 cases are currently scheduled for trial by the end of 2004.

The second type is claims by one manufacturer Pittsburgh Corning Corp. (PCC) against BGE and approximately eight others, as third-party defendants. On April 17, 2000, PCC declared bankruptcy.

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

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

Until the relevant facts for both types of claims are determined, we are unable to estimate what our, or BGE's, liability might be. Although insurance and hold harmless agreements from contractors who employed the plaintiffs may cover a portion of any awards in the actions, the potential effect on our, or BGE's, financial results could be material.

Item 5. Other Information

Forward Looking Statements

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

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

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

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

Item 6. Exhibits and Reports on Form 8-K

(a)	Exhibit No. 3(a)	Bylaws of Constellation Energy Group, Inc. as amended February 27, 2004.
	Exhibit No. 10(a)	Executive Annual Incentive Plan of Constellation Energy Group, Inc., as amended and restated.
	Exhibit No. 10(b)	Constellation Energy Group, Inc. 1995 Long-Term Incentive Plan, as amended and restated.
	Exhibit No. 10(c)	Constellation Energy Group, Inc. Deferred Compensation Plan for Non-Employee Directors, as amended and restated.
	Exhibit No. 10(d)	Constellation Energy Group, Inc. Supplemental Pension Plan, as amended and restated.
	Exhibit No. 10(e)	Constellation Energy Group, Inc. Senior Executive Supplemental Plan, as amended and restated.
	Exhibit No. 10(f)	Change in Control Severance Agreement between Constellation Energy Group, Inc. and Thomas V. Brooks.
	Exhibit No. 10(g)	Constellation Energy Group, Inc. Executive Long-Term Incentive Plan, as amended and restated.
	Exhibit No. 10(h)	Constellation Energy Group, Inc. 2002 Executive Annual Incentive Plan, as amended and restated.
	Exhibit No. 10(i)	Constellation Energy Group, Inc. 2002 Senior Management Long-Term Incentive Plan, as amended and restated.
	Exhibit No. 10(j)	Constellation Energy Group, Inc. Management Long-Term Incentive Plan, as amended and restated.
	Exhibit No. 12(a)	Constellation Energy Group, Inc. Computation of Ratio of Earnings to Fixed Charges.
	Exhibit No. 12(b)	Baltimore Gas and Electric Company Computation of Ratio of Earnings to Fixed Charges and Computation of Ratio of Earnings to Combined Fixed Charges and Preferred and Preference Dividend Requirements.
	Exhibit No. 31(a)	Certification of Chairman of the Board, Chief Executive Officer and President of Constellation Energy Group, Inc. pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
	Exhibit No. 31(b)	Certification of Executive Vice President and Chief Financial Officer of Constellation Energy Group, Inc. pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
	Exhibit No. 31(c)	Certification of President and Chief Executive Officer of Baltimore Gas and Electric Company pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
	Exhibit No. 31(d)	Certification of Senior Vice President and Chief Financial Officer of Baltimore Gas and Electric Company pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
	Exhibit No. 32(a)	Certification of Chairman of the Board, Chief Executive Officer and President of Constellation Energy Group, Inc. pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
	Exhibit No. 32(b)	Certification of Executive Vice President and Chief Financial Officer of Constellation Energy Group, Inc. pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

Exhibit No. 32(c)	Certification of President and Chief Executive Officer of Baltimore Gas and Electric Company pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
Exhibit No. 32(d)	Certification of Senior Vice President and Chief Financial Officer of Baltimore Gas and Electric Company pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

(b) Reports on Form 8-K for the quarter ended March 31, 2004:

Date	**Item Reported**
January 30, 2004	Item 7. Financial Statements and Exhibits Item 12. Results of Operations and Financial Condition

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, each registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

CONSTELLATION ENERGY GROUP, INC.

(Registrant)

BALTIMORE GAS AND ELECTRIC COMPANY

(Registrant)

Date: May 7, 2004

/s/ E. FOLLIN SMITH

E. Follin Smith,
Executive Vice President of Constellation Energy Group, Inc. and Senior Vice President of Baltimore Gas and Electric Company, and as Principal Financial Officer of each Registrant

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