CHARLES H. CRUSE
Vice President
Nuclear Energy

Baltimore Gas and Electric Company
Calvert Cliffs Nuclear Power Plant
1650 Calvert Cliffs Parkway
Lusby, Maryland 20657
410 495-4455

A Member of the
Constellation Energy Group

BGE

August 13, 1999

U. S. Nuclear Regulatory Commission
Washington, DC 20555

ATTENTION: Director, Nuclear ?eactor Regulation

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

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

Exhibit I	A copy of the 1998 Annual Report to Shareholders of Baltimore Gas and Electric Company containing certified financial statements
Exhibit II	A copy of quarterly financial statements as of June 30, 1999
Exhibit III	A copy of Projected Cash Flow for the twelve months ended July 31, 2000
Exhibit IV	Narrative statement on curtailment/deferment of capital expenditures (if any) to ensure that retrospective premiums up to $10 million per reactor year for each nuclear incident would be available for payment.

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

Very truly yours,

Charles H. Cruse

190022

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CHC/JKK/bjd

Attachments: As stated

cc: Document Control Desk, NRC

(Without Attachments)
R. S. Fleishman, Esquire
J. E. Silberg, Esquire
S. S. Bajwa, NRC
A. W. Dromerick, NRC
H. J. Miller, NRC
Resident Inspector, NRC
R. I. McLean, DNR
J. H. Walter, PSC

M001

EXHIBIT II

QUARTERLY FINANCIAL STATEMENTS

AS OF JUNE 30, 1999

Baltimore Gas and Electric Company
Calvert Cliffs Nuclear Power Plant
August 13, 1999

Constellation Energy Group

Quarterly Financial Summary

June 1999

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

Consolidated Statements of Income (Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,		Twelve Months Ended June 30,	
	1999	1998	1999	1998	1999	1998
	(In Millions, Except Per Share Amounts)					
Revenues						
Electric	$ 533.0	$ [illegible]5.2	$1,046.0	$1,024.3	$2,240.9	$2,200.6
Gas	79.9	[illegible]2.0	272.7	262.6	459.5	478.1
Diversified businesses	207.1	160.4	433.6	346.8	776.3	628.4
Total Revenues	820.0	767.6	1,752.3	1,633.7	3,476.7	3,307.1
Expenses Other Than Fixed Charges And Income Taxes						
Electric fuel and purchased energy	120.0	115.6	241.2	242.1	504.8	513.8
Gas purchased for resale	33.0	32.2	135.1	130.4	213.3	241.2
Operations	135.2	139.7	270.5	265.8	558.8	519.1
Maintenance	53.6	57.9	102.4	92.1	187.8	168.4
Diversified businesses - selling, general, and administrative	171.7	126.8	348.0	270.9	627.9	466.8
Write-downs of real estate investments	—	—	—	—	23.7	3.2
Depreciation and amortization	90.8	89.6	181.1	186.1	372.1	358.1
Taxes other than income taxes	51.8	49.6	112.1	106.6	224.9	216.0
Total expenses other than fixed charges and income taxes	656.1	611.4	1,390.4	1,294.0	2,713.3	2,486.6
Income from Operations	163.9	156.2	361.9	339.7	763.4	820.5
Other Income (Expense)						
Write-off of merger costs	—	—	—	—	—	(57.9)
Other income	5.2	0.9	4.5	2.8	7.4	5.9
Total other income (expense)	5.2	0.9	4.5	2.8	7.4	(52.0)
Income Before Fixed Charges and Income Taxes	169.1	157.1	366.4	342.5	770.8	768.5
Fixed Charges						
Interest expense	58.2	58.9	119.3	118.5	241.8	237.7
BGE preference stock dividends	3.4	5.8	6.9	11.6	17.1	24.4
Total fixed charges	61.6	64.7	126.2	130.1	258.9	262.1
Income Before Income Taxes	107.5	92.4	240.2	212.4	511.9	506.4
Income Taxes						
Current	26.4	30.7	75.9	88.1	157.4	177.5
Deferred	15.3	6.1	17.8	(3.9)	39.1	21.7
Investment tax credit adjustments	(2.2)	(1.8)	(4.3)	(3.6)	(9.5)	(7.4)
Total income taxes	39.5	35.0	89.4	80.6	187.0	191.8
Net Income	$ 68.0	$ 57.4	$ 150.8	$ 131.8	$ 324.9	$ 314.6
Earnings Applicable to Common Stock	$ 68.0	$ 57.4	$ 150.8	$ 131.8	$ 324.9	$ 314.6
Average Shares of Common Stock Outstanding	149.6	148.3	149.6	148.1	149.2	147.9
EARNINGS PER COMMON SHARE						
Electric business	$0.37	$0.33	$0.67	$0.63	$1.79	$1.90
Gas business	—	0.01	0.15	0.12	0.21	0.17
Total utility business	0.37	0.34	0.82	0.75	2.00	2.07
Energy Services:						
Power marketing and trading	0.08	0.01	0.13	0.01	0.17	0.01
Power projects	0.04	0.04	0.11	0.11	0.29	0.24
Other energy services	—	—	—	—	(0.01)	(0.05)
Other (primarily real estate and investments)	(0.04)	—	(0.05)	0.02	(0.13)	0.12
Total earnings per share from operations	0.45	0.39	1.01	0.89	2.32	2.39
Write-off of merger costs*	—	—	—	—	—	(0.25)
Write-downs of real estate investments*	—	—	—	—	(0.10)	(0.01)
Write-off of energy services investment*	—	—	—	—	(0.04)	—
Total Earnings Per Common Share and Earnings per Common Share-Assuming Dilution	$0.45	$0.39	$1.01	$0.89	$2.18	$2.13
Investment in utility business at end of period	$2,372.6	$2,390.7	$2,372.6	$2,390.7	$2,372.6	$2,390.7
Investment in diversified businesses at end of period	$ 631.8	$ 509.9	$ 631.8	$ 509.9	$ 631.8	$ 509.9

Results for interim periods, which can be largely influenced by weather conditions, are not necessarily indicative of results to be expected for an entire year.

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

**Nonrecurring charges to earnings.*

Consolidated Balance Sheets (Unaudited)

	June 30, 1999	June 30, 1998
	(In Millions)	
ASSETS		
Current Assets		
Cash and cash equivalents	$ 103.4	$ 302.5
Accounts receivable (net of allowance for uncollectibles of $21.5 and $24.1, respectively)	482.1	388.1
Trading securities	109.4	121.7
Fuel stocks	69.1	75.3
Materials and supplies	149.5	160.5
Prepaid taxes other than income taxes	3.5	3.0
Assets from energy trading activities	317.8	351.3
Other	57.0	28.7
Total current assets	1,291.8	1,431.1
Investments And Other Assets		
Real estate projects and investments	319.2	422.4
Power projects	669.5	539.8
Financial investments	172.6	187.4
Nuclear decommissioning trust fund	199.2	165.0
Net pension asset	96.6	114.8
Other	262.1	217.1
Total investments and other assets	1,719.2	1,646.5
Utility Plant		
Utility plant	8,838.6	8,597.2
Accumulated depreciation	(3,193.5)	(2,966.9)
Net utility plant	5,645.1	5,630.3
Deferred Charges		
Regulatory assets (net)	519.8	560.1
Other	58.2	53.4
Total deferred charges	578.0	613.5
Total Assets	$9,234.1	$9,321.4
LIABILITIES AND CAPITALIZATION		
Current Liabilities		
Short-term borrowings	$ 109.3	$ 72.5
Current portions of long-term debt and preference stock	474.3	631.0
Accounts payable	317.4	200.6
Customer deposits	38.3	32.5
Accrued taxes	3.0	0.6
Accrued interest	55.9	60.5
Dividends declared	66.3	68.0
Accrued vacation costs	36.3	38.7
Liabilities from energy trading activities	180.0	333.1
Other	35.1	26.1
Total current liabilities	1,315.9	1,463.6
Deferred Credits And Other Liabilities		
Deferred income taxes	1,314.3	1,285.3
Postretirement and postemployment benefits	231.9	195.3
Deferred investment tax credits	113.7	123.1
Decommissioning of federal uranium enrichment facilities	30.8	34.9
Other	69.4	58.4
Total deferred credits and other liabilities	1,760.1	1,697.0
Long-Term Debt		
BGE first refunding mortgage bonds	1,429.2	1,570.8
BGE other long-term debt	1,000.8	1,027.8
BGE obligated mandatorily redeemable trust preferred securities	250.0	250.0
Diversified businesses long-term debt	762.6	735.9
Unamortized discount and premium	(11.6)	(13.3)
Current portion of long-term debt	(467.3)	(508.0)
Total long-term debt	2,963.7	3,063.2
BGE Redeemable Preference Stock	7.0	110.0
Current portion of BGE redeemable preference stock	(7.0)	(103.0)
Total BGE redeemable preference stock	—	7.0
BGE Preference Stock Not Subject To Mandatory Redemption	190.0	210.0
Current portion of BGE preference stock not subject to mandatory redemption	—	(20.0)
Total BGE preference stock not subject to mandatory redemption	190.0	190.0
Common Shareholders' Equity		
Common stock	1,494.3	1,454.5
Retained earnings	1,515.5	1,441.3
Accumulated other comprehensive income	(5.4)	4.8
Total common shareholders' equity	3,004.4	2,900.6
Total capitalization	6,158.1	6,160.8
Total Liabilities And Capitalization	$9,234.1	$9,321.4

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

Consolidated Statements Of Cash Flows (Unaudited)

	Six Months Ended June 30, 1999	1998	*Twelve Months Ended June 30,* 1999	1998
	(In Millions)			
Cash Flows From Operating Activities				
Net income	$ 150.8	$ 131.8	$ 324.9	$ 314.6
Adjustments to reconcile to cash provided by operating activities				
Depreciation and amortiza	208.4	209.0	428.7	409.8
Deferred income taxes	17.8	(3.9)	39.1	21.7
Investment tax credit adjustments	(4.3)	(3.6)	(9.5)	(7.4)
Deferred fuel costs	7.1	20.4	(21.6)	11.0
Accrued pension and postemployment benefits	28.7	10.6	59.7	(7.3)
Write-off of merger costs	—	—	—	57.9
Write-downs of real estate investments	—	—	26.2	3.2
Equity in earnings of affiliates and joint ventures (net)	26.2	(11.9)	(16.5)	(39.0)
Changes in assets from energy trading activities	(157.6)	(341.9)	33.5	(351.3)
Changes in liabilities from energy trading activities	53.8	324.5	(153.1)	333.1
Changes in other current assets	(24.4)	104.9	(100.4)	(7.2)
Changes in other current liabilities	68.4	(18.2)	149.8	56.4
Other	(4.7)	(18.3)	5.5	(41.1)
Net cash provided by operating activities	370.2	403.4	766.3	754.4
Cash Flows From Investing Activities				
Utility capital expenditures	(182.3)	(169.9)	(412.1)	(414.7)
Contributions to nuclear decommissioning trust fund	(8.8)	(8.8)	(17.6)	(17.6)
Purchases of marketable equity securities	(12.4)	(16.5)	(29.2)	(29.6)
Sales of marketable equity securities	9.8	18.7	24.0	43.7
Other financial investments	8.5	13.6	4.9	14.1
Real estate projects and investments	40.7	26.9	35.3	27.7
Power projects	(31.8)	(82.1)	(115.9)	(109.2)
Other	(19.2)	(31.2)	(64.9)	(51.8)
Net cash used in investing activities	(195.5)	(249.3)	(575.5)	(537.4)
Cash Flow From Financing Activities				
Proceeds from issuance of				
Short-term borrowings	1,029.3	1,476.1	1,515.4	2,877.7
Long-term debt	127.5	391.4	567.4	485.1
Common stock	9.6	12.6	39.1	21.6
Repayments of short-term borrowings	(920.0)	(1,719.7)	(1,478.6)	(2,922.1)
Reacquisition of long-term debt	(360.5)	(59.1)	(656.6)	(300.2)
Redemption of BGE preference stock	—	(3.0)	(124.9)	(106.0)
Common stock dividends paid	(125.5)	(121.2)	(250.4)	(242.3)
Other	(5.4)	8.7	(1.3)	0.5
Net cash used in financing activities	(245.0)	(14.2)	(389.9)	(185.7)
Net Increase in Cash and Cash Equivalents	(70.3)	139.9	(199.1)	31.3
Cash and Cash Equivalents at Beginning of Year	173.7	162.6	302.5	271.2
Cash and Cash Equivalents at End of Year	$ 103.4	$ 302.5	$ 103.4	$ 302.5
Other Cash Flow Information				
Interest paid (net of amounts capitalized)	$ 120.4	$ 114.7	$ 242.4	$ 235.6
Preference stock dividends paid	$ 6.9	$ 11.6	$ 16.3	$ 25.5
Income taxes paid	$ 101.0	$ 89.9	$ 175.4	$ 168.5

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

Utility Operating Statistics

ELECTRIC	Three Months Ended June 30, 1999	1998	Six Months Ended June 30, 1999	1998	Twelve Months Ended June 30, 1999	1998
Revenues *(In Millions)*						
Residential—with househeating	$ 84.1	$ 83.4	$ 203.6	$ 193.6	$ 402.5	$ 392.9
—other	131.0	131.3	250.7	246.6	560.3	539.7
—total	215.1	214.7	454.3	440.2	962.8	932.6
Commercial	225.0	224.0	423.5	414.1	922.2	897.9
Industrial	51.6	55.3	96.5	100.5	207.5	213.9
System Sales	491.7	494.0	974.3	954.8	2,092.5	2,044.4
Interchange and Other Sales	34.9	25.5	59.3	57.9	122.3	132.2
Other	6.5	5.7	12.9	11.7	28.1	24.3
Total	$ 533.1	$ 525.2	$1,046.5	$1,024.4	$2,242.9	$2,200.9
Sales *(In Thousands)*—MWH						
Residential—with househeating	989	968	2,663	2,487	5,034	4,883
—other	1,388	1,387	2,820	2,747	6,180	5,905
—total	2,377	2,355	5,483	5,234	11,214	10,788
Commercial	3,198	3,178	6,468	6,330	13,357	12,960
Industrial	1,091	1,195	2,194	2,309	4,468	4,621
System Sales	6,666	6,728	14,145	13,873	29,039	28,369
Interchange and Other Sales	1,441	1,063	2,659	2,798	5,315	6,159
Total	8,107	7,791	16,804	16,671	34,354	34,528

GAS	Three Months Ended June 30, 1999	1998	Six Months Ended June 30, 1999	1998	Twelve Months Ended June 30, 1999	1998
Revenues *(In Millions)*						
Residential —excluding delivery service	$ 51.1	$ 49.2	$ 175.9	$ 164.1	$ 291.1	$ 294.6
—delivery service	1.8	0.6	6.7	1.9	9.7	2.4
—total	52.9	49.8	182.6	166.0	300.8	297.0
Commercial—excluding delivery service	12.9	11.5	49.4	44.8	80.2	87.9
—delivery service	4.3	3.6	13.5	10.8	22.2	16.7
Industrial —excluding delivery service	1.1	0.8	4.7	3.6	9.1	8.5
—delivery service	3.5	3.8	8.1	8.2	15.9	16.9
System Sales	74.7	69.5	258.3	233.4	428.2	427.0
Off-System Sales	5.5	10.8	15.1	25.6	30.3	44.3
Other	2.1	1.7	3.8	3.6	7.3	6.8
Total	$ 82.3	$ 82.0	$ 277.2	$ 262.6	$ 465.8	$ 478.1
Sales *(In Thousands)*—DTH						
Residential —excluding delivery service	5,148	5,160	21,460	20,911	34,143	36,726
—delivery service	554	227	2,403	718	3,575	924
—total	5,702	5,387	23,863	21,629	37,718	37,650
Commercial—excluding delivery service	1,657	1,514	7,455	7,166	12,065	14,404
—delivery service	3,977	3,402	11,278	9,315	18,596	15,401
Industrial —excluding delivery service	101	50	782	519	1,676	1,360
—delivery service	7,369	8,527	16,192	17,180	33,810	37,204
System Sales	18,806	18,880	59,570	55,809	103,865	106,019
Off-System Sales	2,263	4,710	6,382	10,604	12,502	17,079
Total	21,069	23,590	65,952	66,413	116,367	123,098

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

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

Heating/Cooling Degree Days (Calendar—Month Basis)

	Three Months 1999	1998	Six Months 1999	1998	Twelve Months 1999	1998
Heating degree days—Actual	517	463	2,907	2,485	4,541	4,383
—Normal	531	534	2,987	3,011	4,759	4,822
Cooling degree days—Actual	203	258	204	279	839	843
—Normal	230	227	233	230	840	814

Utility Electric Generation Statistics

Twelve Months Ended June 30,

	Nuclear	Coal	Oil	Hydro & Gas	Purchased Power Net of Energy Sales	Total
Generation by Fuel Type (%)						
1999	43.3	57.3	4.3	3.0	(7.9)	100.0
1998	44.8	60.1	2.3	3.7	(10.9)	100.0
Thousands of MWH						
1999	13,312	17,642	1,330	922	(2,431)	30,775
1998	13,439	18,024	687	1,103	(3,256)	29,997
Average Cost of Fuel (Cents per Million Btu)						
1999	45.52	137.53	214.42	—	—	101.65
1998	45.96	138.88	267.51	—	—	102.07

Supplemental Financial Statistics

	Twelve Months Ended June 30, Utility		Consolidated	
	1999	1998	1999	1998
Capitalization*				
Long-term debt	45.5%	46.9%	47.2%	48.4%
BGE obligated manditorily redeemable trust preferred securities	4.7%	4.6%	3.7%	3.6%
Short-term borrowings	2.1%	—	1.6%	1.1%
BGE preference stock	3.7%	5.8%	2.9%	4.7%
Common equity	44.0%	42.7%	44.6%	42.2%
Return On Average Common Equity				
Reported	12.5%	11.2%	10.9%	10.9%
Excluding nonrecurring charges to earnings**	12.5%	12.7%	11.6%	12.2%
Ratio Of Earnings (SEC Method)				
To fixed charges	3.32	3.39	3.02	3.11
To fixed charges and preference dividends combined	2.94	2.81	2.74	2.68
AFC As A % Of Earnings Applicable To Common Stock	3.7%	3.5%	3.2%	3.0%
Effective Tax Rate	34.7%	35.7%	36.5%	36.1%

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

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

***Nonrecurring charges to earnings include the write-off of merger costs and of an energy services investment, and the write-downs of real estate investments as shown on the Consolidated Statements of Income.*

Common Stock Data

	Three Months Ended June 30,		Twelve Months Ended June 30,	
	1999	1998	1999	1998
Common Stock Dividends—Per Share				
—Declared	$0.42	$0.42	$1.68	$1.65
—Paid	$0.42	$0.41	$1.68	$1.64
Market Value Per Share				
—High	$31 1/8	$32 15/16	$35 1/4	$34 5/16
—Low	$25 1/8	$30 3/8	$24 11/16	$25 13/16
—Close	$29 3/8	$31 1/16	$29 3/8	$31 1/16
Shares Outstanding—End of Period *(In Millions)*	149.6	148.3	149.6	148.3
Book Value per Share—End of Period	$20.09	$19.55	$20.09	$19.55

Inquiries concerning this summary should be directed to:

David A. Brune
Vice President,
Chief Financial Officer,
and Secretary
(410) 234-5511

Kevin J. Miller
Manager,
Financial Planning
(410) 234-5434

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

EXHIBIT III

PROJECTED CASH FLOW FOR 12 MONTHS

ENDED JULY 31, 2000

Baltimore Gas and Electric Company
Calvert Cliffs Nuclear Power Plant
August 13, 1999

Internal Cash Flow Projection
For Calvert Cliffs Nuclear Power Plant

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

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

	Twelve Months Ended 6/30/99	Projected Twelve Months Ended 7/31/00
Non - Cash Expenses ($000)		
Depreciation and Amortization	$421,914	$434,866
Deferred Income Taxes and Investment Tax Credits	7,140	(3,382)
Total	$429,054	$431,484
Percentage of Total to Maximum Total Contingent Liability Payable Per Year	2,145.3%	2,157.4%
Retained Earnings ($000)		
Net Income After Taxes	$331,833	
Less Allowance for Funds Used During Construction	10,487	
Less Dividends paid	266,652	
Total	$ 54,694	
Total Internal Cash Flow	$483,748	
Percentage of Total Internal Cash Flow Maximum Total Contingent Liability Payable Per Year	2,418.7%	

Baltimore Gas and Electric Company

Underlying Assumptions for Projected Cash Flows

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

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

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

(4) Accounting policies are consistent with those in effect June 30, 1999.

EXHIBIT IV

NARRATIVE STATEMENT

CURTAILMENT OF CAPITAL EXPENDITURES

Baltimore Gas and Electric Company
Calvert Cliffs Nuclear Power Plant
August 13, 1999

Exhibit IV

Baltimore Gas and Electric Company

Curtailment of Capital Expenditures

Estimated construction expenditures including nuclear fuel and Allowance for Funds Used During Construction for the twelve months ended July 31, 2000 are $433 million. To insure that retrospective premiums under the Price Anderson Act would be available during the aforementioned twelve month period without additional funds from external sources, construction curtailments would affect all construction expenditures rather than impacting a specific project.

EXHIBIT I

1998 ANNUAL REPORT TO SHAREHOLDERS

Baltimore Gas and Electric Company
Calvert Cliffs Nuclear Power Plant
August 13, 1999

1998 ANNUAL REPORT TO SHAREHOLDERS

DETERMINED TO WIN

BGE

BGE

Financial Highlights

	1998	1997	% Change
	(In millions, except per share amounts)		
COMMON STOCK DATA			
Earnings per share			
Earnings per share from operations			
Utility business	$ 1.93	$ 1.94	(0.5)%
Diversified businesses	0.27	0.34	(20.6)%
Total earnings per share from operations	$ 2.20	$ 2.28	(3.5)%
*Write-off of merger costs	—	(0.25)	—
*Write-downs of real estate investments	(0.10)	(0.31)	—
*Write-off of energy services investment	(0.04)	—	—
Total earnings per share	$ 2.06	$ 1.72	19.8%
Dividends declared per share	$ 1.67	$ 1.63	2.5%
Average shares outstanding	148.5	147.7	0.5%
Return on average common equity			
Reported	10.5%	8.9%	18.0%
Excluding nonrecurring charges to earnings	11.2%	11.7%	(4.3)%
Book value per share—year-end	$ 19.98	$ 19.44	2.8%
Market price per share—year-end	$30.875	$34.125	(9.5)%
FINANCIAL DATA			
Revenues			
Electric	$ 2,219	$ 2,192	1.2%
Gas	449	522	(13.9)%
Diversified businesses	690	594	16.1%
Total revenues	$ 3,358	$ 3,308	1.5%
Net income	$ 328	$ 283	15.8%
Earnings applicable to common stock	$ 306	$ 254	20.4%
Assets			
Utility business	$ 7,271	$ 7,305	(0.5)%
Diversified businesses	1,924	1,595	20.6%
Total assets	$ 9,195	$ 8,900	3.3%
Utility construction expenditures (excluding Allowance for Funds Used During Construction)	$ 329	$ 365	(9.9)%
BGE investment in diversified businesses	$ 515	$ 488	5.5%
UTILITY SYSTEM DATA			
Electric system sales—megawatt hours	28.8	28.1	2.5%
Gas system sales—dekatherms	100.1	112.4	(10.9)%

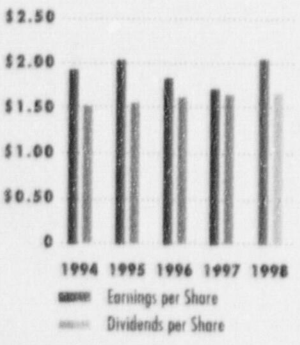
**Nonrecurring charges to earnings discussed in Note 2 to the Consolidated Financial Statements on page 51.*
Certain prior-year amounts have been reclassified to conform with the current year's presentation.

Contents

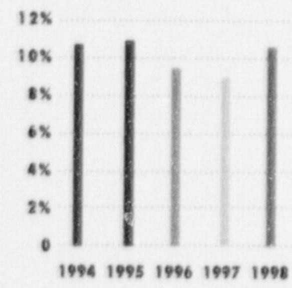
COMMITTED TO EQUAL OPPORTUNITY As an Equal Opportunity Employer, BGE does not discriminate on the basis of age, color, disability, marital status, national origin, race, religion, sex, sexual orientation, or veteran status.

Nobody just steps out on the court and wins. You have to have a **plan**. You have to make tough choices. You have to be **committed**. And you have to work at it, and work at it, and **work** at it. That's what matters on the court and in the evolving energy marketplace. Today hundreds of experienced power companies are competing for good position along with a host of niche players and newcomers. While it's early on in the game, BGE's made some **smart plays** with a growing wholesale power business, a solid commitment to power generation, and a pro-customer choice stance at home. In the end, BGE plans to be a **winner**. That's why we're doing everything we can to prepare. Building a strong team. Setting competitive **strategies**. And playing hard, very hard. Bottom line, at BGE, **we're determined to win**.

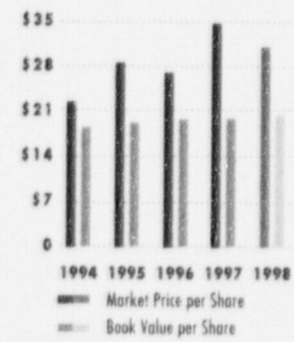
Earnings and Dividends
Declared per Share of Common Stock



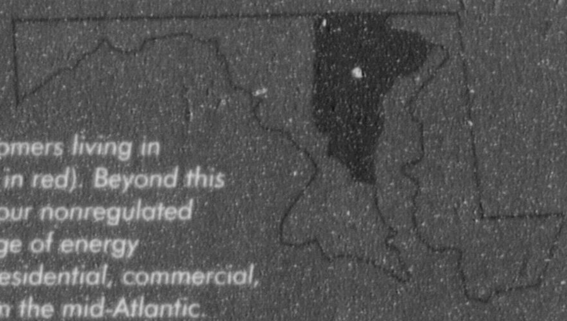
Return on Average Common Equity



Common Stock Market Price
and Book Value per Share



BGE: AT-A-GLANCE



REGIONAL

Our traditional electric and gas utility serves customers living in Central Maryland (shown in red). Beyond this 10-county region, two of our nonregulated affiliates offer a wide range of energy products and services to residential, commercial, and industrial customers in the mid-Atlantic.

Our Constellation Power Source affiliate buys and sells energy and provides risk-management services throughout the U.S and into Canada. Our Constellation Pow affiliate builds and operates power plant throughout the U.S.

Our Utility Business

Our regulated, investor-owned electric and gas utility serves more than 1.1 million industrial, commercial, and residential electric customers and over 573,000 gas customers in Central Maryland.

Operations:

- **Generation:** Owns and operates 10 Maryland-based power stations, including the Calvert Cliffs Nuclear Power Plant; shares ownership of three power plants in Pennsylvania; total generating capacity exceeds 6,200 megawatts
- **Electric Transmission and Distribution:** Provides electricity throughout its 2,300-square-mile service territory through its transmission and distribution system; is a member of the PJM (Pennsylvania-New Jersey-Maryland) Interconnection, a regional power pool of wholesale market participants and eight utility companies
- **Gas Distribution:** Stores and delivers natural gas through two peak-shaving plants, nine gate stations, and nearly 5,600 square miles of gas mains in a more than 600-square-mile service territory

1998 Highlights:

- Set new production records in fossil and nuclear plants by generating 32.4 million megawatt hours, an increase of 14% since 1994
- Became first in the U.S. to file for nuclear-plant relicensing to extend Calvert Cliffs Nuclear Power Plant's operating license
- Filed transition plan for introducing electric retail competition with the Maryland Public Service Commission (PSC)
- Gained $16 million natural gas base rate increase that included a provision to protect revenues from weather fluctuations
- Added nearly 12,000 new natural gas customers and more than 15,600 electric customers to system
- Ranked in the top 17th percentile of comparable utilities for safety performance

Our Nonregulated

BGE's nonregulated businesses, consolidate under its wholly owned subsidiary, Constellation® Enterprises, Inc., focus on emerging opportunities in the competitive energy marketplace.

Constellation Power Source,™ Inc.

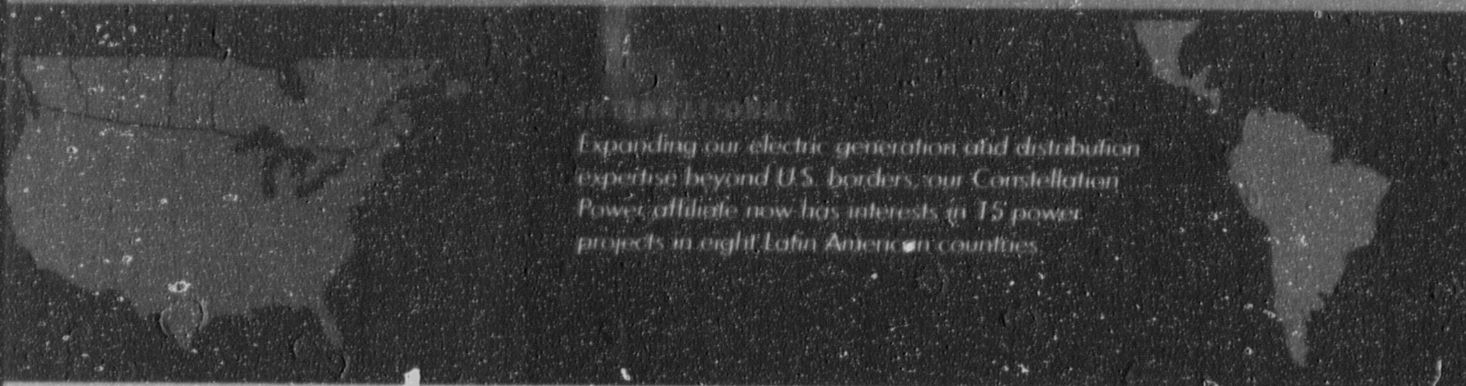
Description:
Provides wholesale power-marketing and risk management services, with Goldman Sachs Power as its exclusive advisor

Customers and Markets:
Wholesale energy customers in North Americ

1998 Highlights:

- Increased trading volume nearly 12-fold to 116 million megawatt hours compared to 9 million in 1997
- Developed New England business base by entering into long-term contracts with Gran State Electric Company, Fitchburg Gas and Electric Company, and Eastern Utilities Associates
- Formed Orion Power Holdings, Inc. with Goldman Sachs Capital Partners to pursue purchasing existing power plants in North America
- Orion acquired the 105-megawatt Carr Stre power plant in Syracuse, NY
- Entered into five-year contract to purchase all capacity, energy, and ancillary services generated by Carr Street power plant
- Moved into new downtown Baltimore head-quarters with a state-of-the-art trading floor

Baltimore Gas and Electric Company (BGE) is an investor-owned energy company combining a core electric and gas utility with diversified businesses. In 1998, combined revenues totaled $3.4 billion.



Energy Services Businesses*

Constellation Power,™ Inc.

Description:
Develops, owns, and operates domestic and international power projects; provides operations and maintenance services to energy facilities through its wholly owned subsidiary, Constellation Operating Services, Inc. (COSI)

Customers and Markets:
Wholesale and retail energy markets in the U.S. and Latin America

1998 Highlights:
- Set production record of over 4 million megawatt hours, the most ever generated by its domestic power plant portfolio
- Reorganized management team, aligning operations to pursue wholesale power-marketing and merchant-generation strategies
- Acquired controlling interest in Elektra Noreste, S.A., Panama's second-largest electric distribution company
- COSI gained contract to operate Carr Street power plant in Syracuse, NY
- Signed long-term power-supply agreement with privatized Guatemalan distribution company; added 60 megawatts of new generating capacity

BGE Home Products and Services,™ Inc.

Description:
Offers a wide range of home energy products and services; commercial building systems; and retail gas marketing

Customers and Markets:
Residential and commercial customers in MD, VA, and Washington, D.C.

1998 Highlights:
- Added natural gas to its existing portfolio of products and services to take advantage of opportunities opening with the deregulation of the retail natural gas supply market
- Concluded sales and marketing drive as a participant in Maryland's Gas Options pilot program, attracting significant interest from residential and small-commercial markets
- Won two "Baltimore's Best" Awards from *Baltimore* magazine for appliance stores and plumbing services
- Continued to strategically reposition retail operations, relocating two existing stores and opening a third in a new market

Constellation Energy Source,™ Inc.

Description:
Provides customized energy solutions exclusively to businesses

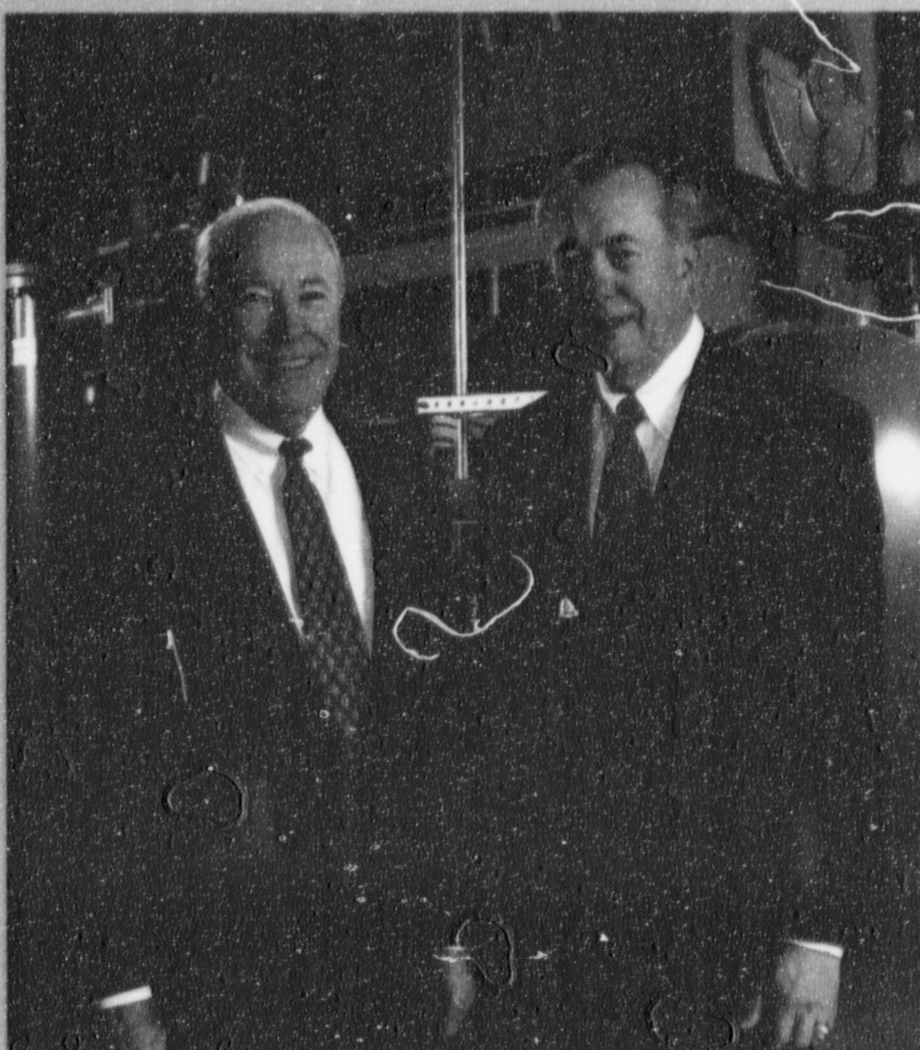
Customers and Markets:
Mid-sized commercial and industrial customers primarily in the mid-Atlantic region

1998 Highlights:
- More than doubled natural gas sales in one year
- Expanded product line to offer full complement of energy and energy-related services to mid-sized commercial, industrial, and governmental customers
- Invested in new information systems to support large transaction volumes required to serve sophisticated customers' complex energy needs

** BGE also has other nonregulated businesses that are not energy-related:*
- *Constellation Investments,™ Inc. engages in financial investments, including marketable securities, financial limited partnerships, and financial guarantee insurance companies.*
- *Constellation Real Estate Group,™ Inc. develops, owns, and manages real estate and senior-living facilities.*

DETERMINED TO WIN
BGE

LETTER TO OUR



Our Strategies

- *Continue to Offer Premier Utility Services to Maryland While Managing the Transition to a Competitive Energy Marketplace*
- *Be a Leader in Wholesale Power Marketing and Generation in North America*
- *Be a Significant Generation and Energy Delivery Supplier in Latin America*

Edward A. Crooke
Vice Chairman

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

Today, and for the foreseeable future, the best description for our business is "an industry in transition." Transition means change, and change is filled with uncertainty. The events of 1998 bear this out.

We're determined to win in the new energy market. As we go through this transition, we'll work to preserve the integrity of your investment, shed assets that no longer fit the emerging market, and seize opportunities for growth.

SHAREHOLDERS

In this transition year, BGE's stock performed below our standards and my own expectations. To be candid, our stock performed in the lowest quartile among utilities in our peer group. I attribute this to the following:

- Flat earnings due to less energy demand caused by mild weather in the fall and winter, and write-downs on projects resulting from our decision to sell a real estate investment and exit an energy services venture.
- Anticipated lower future revenues from 15 California power projects with power purchase agreements. Owned by our Constellation Power affiliate, these projects will have transitioned from fixed to variable rates by the end of the year 2000.
- A rate reduction proposed by the Maryland Office of People's Counsel to the Maryland Public Service Commission (PSC) that could reduce BGE's earnings potential.
- The regulatory and legislative process under way in Maryland to move to a competitive electric market. Investors are uncertain about how key issues such as transition cost recovery and fair tax treatment for utilities will be resolved.

I assure you that your leadership team is acutely aware of how these issues affect the value of your stock. We are working hard on many fronts to resolve them and are encouraged by our progress.

I am especially happy to report that legislation was passed and signed into Maryland law early in 1999, removing a 1910 Maryland statute that prevented BGE from forming a holding company. You'll find more detail on page 6, but I want you to know I was overwhelmed by the strong show of support from local investors and our employees, as well as community and business leaders, on the holding company issue. I thank each of you for your help. It truly made a difference.

A Look at the Scorecard

In 1998, BGE earned $305.9 million, or $2.06 per common share, on revenues of $3.4 billion. This compares with earnings in 1997 of $254.1 million, or earnings per share of $1.72 on revenues of $3.3 billion.

Both 1998 and 1997 earnings reflect one-time charges, explained in the financial section of this report. Excluding the effect of the nonrecurring charges, earnings for 1998 were $2.20 per share compared with $2.28 for 1997. Dividends declared amounted to $1.67 per common share in 1998 and $1.63 per common share in 1997.

Our Utility Business Our utility business includes our regulated electric and gas sales, production, and delivery services. Earnings from these businesses in 1998 were about the same as in 1997. Although we had higher electric sales, we also had lower gas sales, along with higher operations, maintenance, and depreciation expenses.

During the year we added about 15,600 electric and 12,000 gas customers. Total electric sales to customers increased approximately 2.4%, mostly due to customer growth, increased demand during the hot summer, and increased usage per customer. Electric sales to residential customers were up almost 1.5%, while sales to commercial and industrial customers increased 2.9%.

Total gas sales to customers decreased 10.9% compared with 1997, due to 1998's mild winter and fall weather and lower usage per customer. Sales to residential customers decreased 11.6%, while sales to commercial and industrial customers decreased 10.5%.

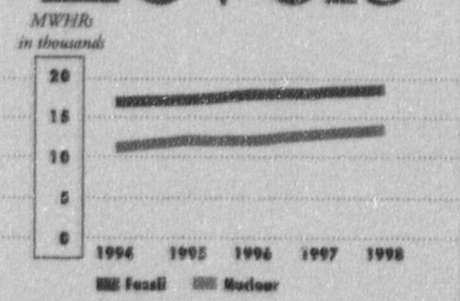
BGE power plants had another record-setting year. In 1998, our Calvert Cliffs Nuclear Power Plant (CCNPP) generated 13.3 million megawatt hours of energy, its highest production level since it began operation 22 years ago. Our fossil plants also set a new production record of 19.1 million megawatt hours.

For the fourth year in a row, our BGE generation team also distinguished itself as the lowest-cost electricity provider among the eight utilities that are included in the PJM (Pennsylvania-New Jersey-Maryland) power pool.

In April 1998, BGE also became the first utility in the country to file with the Nuclear Regulatory Commission to extend the operating licenses of CCNPP's two nuclear units. Since then, several other utilities have filed or plan to file for extensions in the near future. This process will help ensure a diverse fuel mix for our nation's energy consumers, allowing our country and our state to meet stringent new domestic and international air quality standards.

We are on target to be Year 2000 (Y2K) ready. Our utility operations are on schedule to be completely Y2K-ready by mid 1999. We've made a significant investment and have been working with the PSC and other utilities to ensure system reliability. Simply put, our customers can expect the same high level of service reliability during and after the millennium rollover as they experienced before it.

Production Levels



To meet growing demand, BGE generated 32.4 million megawatt hours of electricity in 1998. This is a 3.5% increase over the record we set in 1997.

Our Nonregulated Businesses
Earnings from our nonregulated affiliates reflect solid performance. Excluding the write-downs taken in 1998 and 1997, our nonregulated business operations produced $41.1 million in earnings ($.27 per share) in 1998 compared with $50.5 million ($.34 per share) in 1997.

Write-downs for 1998 included investments in Church Street Station—an entertainment complex in Florida—and an energy services venture. The net result: Nonregulated earnings were $20.2 million in 1998 compared with $4.5 million in 1997.

The major contributors to nonregulated earnings in 1998 were Constellation Power, Inc. (CPI), our largest operating subsidiary, and Constellation Power Source, Inc. (CPS), our newest operating subsidiary. CPI contributed $44.3 million ($.30 per share) to earnings compared with $36.6 million ($.25 per share) in 1997. CPS weighed in with a $7.5 million ($.05 per share) contribution in its first full operating year.

A Brighter Outlook Ahead

We have been working hard to resolve several issues that held us back in 1998 and to position your company to win in the competitive energy market. Here are some of our successes:

Holding Company Bill Passes After the close of the 1998 legislative session last April, we worked to achieve an understanding with Maryland's governor and legislative leaders on the importance of a holding company to BGE's future. A 90-year-old law made our state the only one in the nation prohibiting a utility from forming a holding company.

By June, we received commitments from Maryland's governor, senate president, and speaker of the house that this outdated law would be changed early in the '99 session. I am pleased to report that state lawmakers voted overwhelmingly to allow utilities incorporated in Maryland to form holding companies. The bill was signed into law on February 3, 1999.

This puts BGE on equal footing with other gas and electric utilities serving Maryland customers but incorporated out of state. This also gives us greater access to the capital markets and the financial flexibility to build our businesses.

The final steps will be receiving approvals from the Nuclear Regulatory Commission and from shareholders at our annual meeting in April.

Moving Toward Comprehensive Legislation for Electric Deregulation In December 1997, the PSC set July 1, 2000 as the date when Maryland customers would begin to choose their electric suppliers. State lawmakers then debated the issues surrounding deregulation in the '98 session. While no bill was introduced, the debates raised awareness of the complex and important issues needing resolution before deregulation begins.

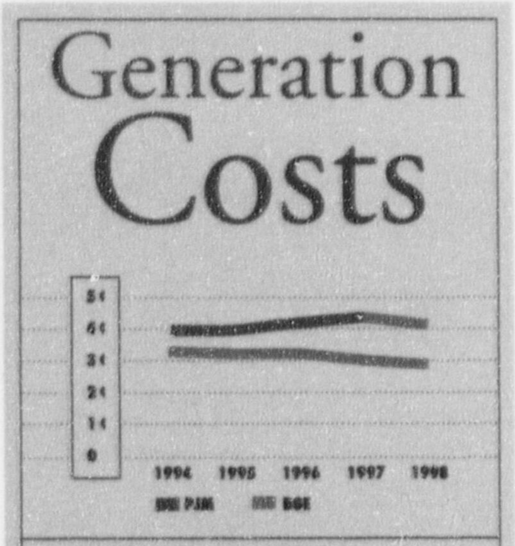
Since that session, BGE and the other utilities serving Maryland have continued to work on proposed legislation. Together, the six utilities developed a series of bills for consideration by the Maryland General Assembly leadership.

We have set out to achieve a broad consensus on the main elements, taking into consideration the views of all stakeholders—customers, regulators, legislators, community leaders, and shareholders. Our objective is to find the fairest and fastest way to open the state's energy market and resolve the uncertainties the transition has created.

All along, we've sensed a commitment to doing it right the first time to ensure an efficient and equitable market that benefits customers and producers alike. We are continuing to work with Maryland's electric industry leaders and state lawmakers to pass comprehensive legislation in 1999.

Focusing Affiliate Businesses on Energy We have reorganized and streamlined our subsidiary structure and focused our activities on the business we know best—energy. For our nonenergy-related businesses we are evaluating transitional strategies.

Toward that end, our Constellation Real Estate Group (CREG) transferred most of its operating properties to Corporate Office Properties Trust (COPT), a publicly traded real estate investment trust based in Philadelphia. In exchange, CREG received a significant stock ownership position in COPT, cash, and relief from associated property debt.



Since 1994, BGE has lowered its generation costs by 11%. For the fourth consecutive year, BGE generation was the lowest-cost electricity provider in the PJM power pool.

Strategies for the Transition

Our pre-eminent goal for the next few years is to actively manage the transition to a competitive electric market. At the annual shareholders meeting in April 1998, I announced the strategies for success going forward. Since then, we've narrowed our focus and set our sights on three primary strategies. We go into more detail on pages 8-16, but here is a brief overview of our game plan:

Provide Premier Utility Services to Maryland While Managing the Transition to Competitive Energy Markets We've been serving Maryland customers for nearly two centuries, and we want to continue to have a strong corporate presence here. Throughout most of this decade we've been preparing our operations for competition. We've improved reliability and service, lowered costs, and increased our power plant production. As the retail energy markets open in Maryland, we plan to remain the state's leader in energy delivery services.

Be a Leader in Wholesale Power Marketing and Generation in North America In less than two years, Constellation Power Source, our power marketing and trading business, has become one of the top 25 power marketers in the U.S. To build on this success, we've realigned subsidiary operations to support our merchant-generation and power-marketing strategy. We have assembled the full spectrum of skills and services that will allow us to be a major player in North America's emerging merchant electric industry. Within our family of nonregulated companies, we have the know-how to build, buy and operate power plants, trade the output on the open market, and manage the risk of fluctuating energy prices.

Become a Significant Generation and Energy Delivery Supplier in Latin America Constellation Power, our independent power business, began expanding its expertise in generation and energy delivery beyond our borders three years ago. It now has 15 projects in eight Latin American countries. We intend to build on our winning track record and increase our involvement in the government privatization process now under way in this geographic region.

Taking Our Best Shots

Ice hockey great Wayne Gretzky has two rules that sum up his approach to the game. First, "I skate to where the puck is going to be." Second, he says, "You miss 100 percent of the shots you never take." That is exactly how BGE approaches the utility business.

Being determined to win in the new energy world means taking the long view but focusing quickly. It means having the confidence to seize upon well-considered risks. Most importantly, it means playing the game on many levels by thinking locally, regionally, nationally, and globally—because the energy market of the next century is that broad and expansive.

In 1999, we'll continue to move quickly in response to promising and profitable opportunities. We're building on a 182-year record of achievement, and we know what it takes to win. I look forward to telling you of our progress this time next year.

I want to thank our employees for their tireless commitment to assuring reliable and responsive services to our customers. Their daily actions are representative of the kind of teamwork and dedication that will make BGE a winner in the energy industry of the future. Finally, I thank you for sharing my confidence in BGE's financial success.

C H Poindexter

Christian H. Poindexter
Chairman of the Board, President
and Chief Executive Officer
February 11, 1999


CONCENTRATE ON OUR HOME-FIELD ADVANTAGE IN MARYLAND
BGE's gas pipes and electric wires will remain a first-class delivery system.

The home team always has an advantage. That's because they know the field, they know the fans, they know how to win on their own turf.

BGE has had that edge for more than 180 years as Central Maryland's hometown utility. As the biggest local player, we've continually worked and evolved to help meet Maryland's growing energy needs, giving customers and shareholders their money's worth every season.

Now, of course, the rules are all changing. It won't be long before we're not the only game in town.

At BGE, we don't intend to lose our hometown edge. We've developed some strategies to help us keep that edge. We plan to:

- Maintain our premier energy delivery service levels for our Maryland customers;
- Build on the reliable and low-cost generation legacy while helping to manage a smooth transition to customer choice;
- Remain a leader in the competitive retail energy markets opening in the region.

GAME PLAN:

- Focus on continuing as the leader in energy delivery in Central Maryland.
- Build on our proven strengths as a reliable, low-cost energy producer as Maryland transitions to customer choice.
- Leverage our experience and reputation in Maryland by continuing to grow our retail energy products and services business.

Concentrate on Our Home-Field Advantage in Maryland

STRATEGY:

Continue to offer premier utility services to Maryland while managing the transition to a competitive marketplace.

Our Premier Energy Delivery Service

Deregulation in the utility industry means that customers will be able to choose where they buy their energy. No matter which company they buy from, customers will still depend upon the utility to deliver that energy safely and reliably to their homes and businesses. That's why we're concentrating on our energy delivery systems in Central Maryland.

BGE Steps Up to the Plate to Prepare for Customer Choice With choice, virtually every customer transaction we now do is subject to change. Making sure our systems are ready and our customers are educated for the changes ahead is a monumental task. Given the impact these changes have, it is a job that cannot be done in a vacuum.

BGE has stepped up to the plate. We are a significant player in the process, participating in the numerous Maryland PSC roundtables and technical groups. We are now working through the many regulatory details necessary to draw a blueprint for how customer choice will work.

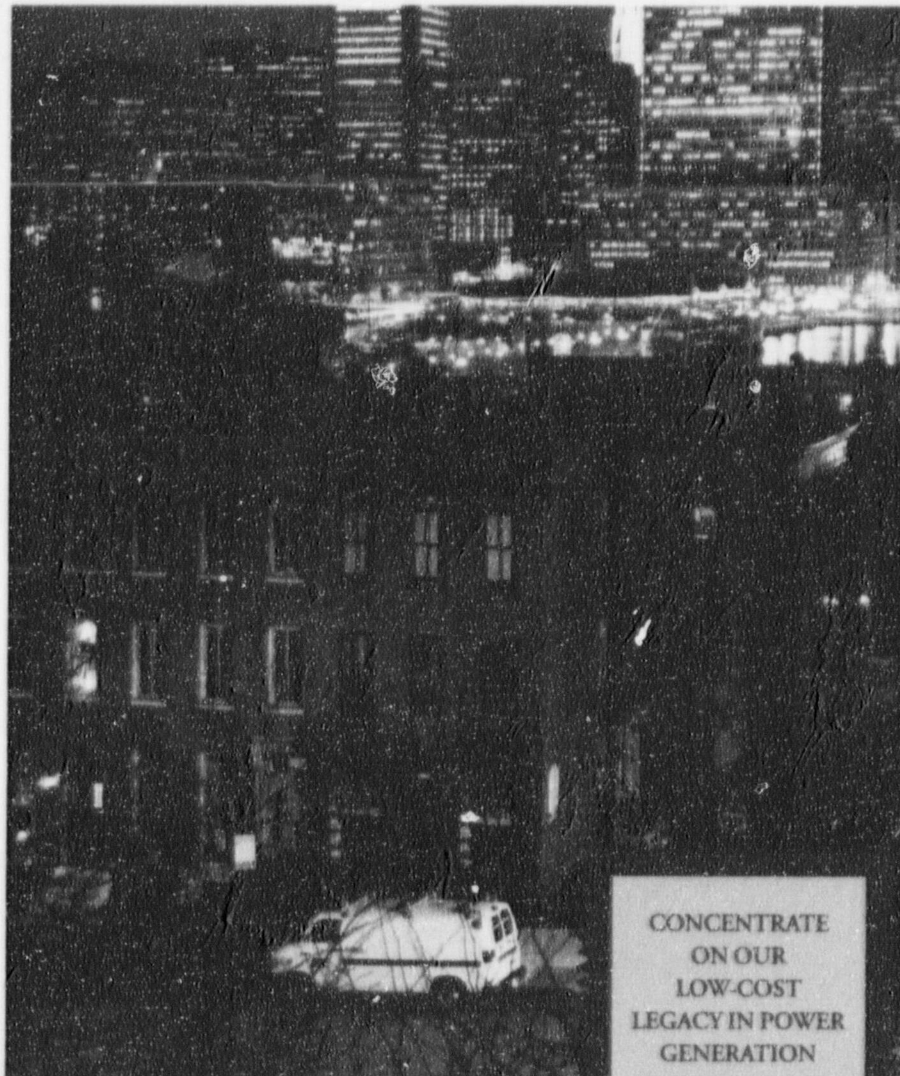
To meet the PSC's year-2000 deadline, we're now upgrading our information systems necessary to support customer choice. We're creating a new retail supplier information system, and we're extending the ability of our customer information system. Together they will allow BGE to enroll customers and suppliers in retail electric choice, keep track of customer/supplier relationships, bill and collect revenues, as well as account for all energy used on our delivery system.

Investing to Improve Access and Reliability Before and after deregulation, we plan to continue serving Central Maryland as a recognized leader in energy delivery. Toward that end, we continue to invest in our system of pipes and wires.

This year the PSC approved a $16 million natural gas distribution rate increase to help us maintain our gas system. We continue to enlarge our gas distribution system to give even more customers the opportunity to choose gas for their homes and businesses. In 1998, we added 112 miles of gas lines and about 12,000 new customers.

BGE is technologically transforming our electric distribution substations to improve reliability and reduce costs. Our system control integration program has replaced older components with compact microprocessor-based relays, meters, and other control systems. The program is expected to reduce costs in new substation construction and ongoing maintenance.

We've also continued to expand the use of our industry-recognized distribution automation system, a sophisticated system designed to restore customers' interrupted power in minutes. Since 1994, investments in such programs and other system-wide upgrades have helped reduce the number of unplanned outages by 38% and the duration of those outages by 20%.



CONCENTRATE ON OUR LOW-COST LEGACY IN POWER GENERATION

BGE has lowered generation costs by 1[illegible]% in the last five years.

Delivering on Customer Satisfaction

Customer satisfaction is something BGE has regularly delivered to Maryland. BGE's "excellent job" ratings with residential customers rank us in the top quartile among investor-owned utilities in the country. In recent years, we've concentrated on improving reliability and power quality for our major customers. Just three years ago, our large industrial customer satisfaction score was good, but not good enough. So BGE account executives went to work. Our results this year prove our efforts make a difference. We improved by 17 percentage points.

We're Preparing for the Year 2000 and Beyond BGE began tackling the Year 2000 (Y2K) challenge in 1996. Since then, experts throughout the company have been working to ensure our systems are ready for a smooth Y2K conversion. The good news is many of our utility systems are Y2K-ready. Where needed, the team has begun repairing and testing. We are on target for our systems to be Y2K-ready by June 1999.

We've also been checking on the Y2K-readiness status of all of our suppliers. Plus, we're working with industry groups such as the North American Electric Reliability Council, Edison Electric Institute, Electric Power Research Institute, American Gas Association, and our partners in the PJM power pool, to plan operations to allow for a smooth transition to the new century.

Generating Winning Numbers

Maryland customers will soon have a choice in their energy suppliers, which will change how our power plants do business. In the meantime, we're working to provide a smooth transition so that when competition comes, our customers, shareholders, and our power plants will be in a position to win.

To compete in the new electric generation market, our power plants must be able to produce winning numbers—low costs, high capacity factors, strong safety and environmental records, and consistently reliable operations.

For the past several years, BGE's power plants have been putting up the right numbers. In 1998, our combined fossil and nuclear energy generators posted the lowest costs among the PJM power pool utilities for the fourth consecutive year. BGE plants have also increased their production levels every year in this decade.

For the fourth year in a row, our nuclear facility was well within the top 10% for individual safety in the industry. Plus, the fossil generation group again topped its own all-time low record for OSHA recordable accidents, which also should place it in the top 10% of its comparison companies.

We've maintained a solid reliability record, too. Our predictive maintenance practices helped us achieve the lowest forced outage rate in the PJM for the fourth consecutive year. That means our plants keep producing when it's most profitable to do so.

BGE's Commitment to the Environment Remains Strong Since the Clean Air Act in 1970, BGE has invested hundreds of millions of dollars in cleaner air, and we continue to make significant reductions to our emissions.

We are meeting or doing better than regulations require on our sulfur dioxide emissions by burning low-sulfur coal, generating nearly half our electricity using emissions-free nuclear fuel and hydroelectric power, retiring several older plants, and installing emissions-reducing equipment.

To comply with the 1990 Clean Air Act Amendments and reduce our nitrogen oxide emissions, we expect to spend about $126 million by 2003. We plan to continue to install new technology at our plants to further reduce emissions to comply with new regulations.

Our Retail Energy Products and Services Role

CONCENTRATE ON EMERGING COMPETITIVE ENERGY-RELATED RETAIL MARKETS IN MARYLAND

BGE HOME just added natural gas to the full line of energy products and services.

BGE first opened its electric and gas appliance stores in the 1920s. Several years ago, we transferred this business to our BGE Home Products & Services (BGE HOME) affiliate. Today, BGE HOME has expanded its product lines to include not only all major brands of appliances, but electronic and entertainment products, plumbing and home improvement services, as well as heating and air conditioning systems.

In fact, in 1998 BGE HOME was voted *Baltimore* magazine's "Best of Baltimore" as the city's foremost appliance and plumbing service source.

Winner in the Gas Pilot Program A new role for BGE HOME is as a marketer and seller of natural gas. This summer BGE HOME entered Maryland's residential Gas Options pilot program. A competitive success, BGE HOME attracted the most customers of any participant.

A New Play with Constellation Energy Source While BGE HOME serves residential and small-commercial customers in Maryland, Constellation Energy Source is concentrating on mid-sized industrial and commercial customers. This year we have repositioned this business to provide a wide range of energy products and services to meet the complex energy needs of sophisticated customers in the mid-Atlantic region.

The Game Goes On Maryland's energy picture is changing. Going forward, we intend to continue to be a corporate leader in Maryland. BGE is managing the game at hand and putting the plays in place to maintain our winning edge.

Having the home-court advantage is one thing, but to succeed in the new wholesale power market, you've got to know how to go coast-to-coast.

Competition might be opening slowly in the retail energy markets, but the wholesale power market opened in 1992. It's been on the fast track ever since. Emerging businesses such as power marketing and merchant generation have achieved tremendous growth and have shown no signs of letting up.

The field of competitors, of course, has become crowded quickly. Two years ago, BGE entered the race, too, but we didn't come in to sit back in the pack. We came in knowing that to succeed, we'd need skill, instinct and agility. We'd also need the nerve to take risks and the judgment to know when not to take them. And most importantly, we knew we'd need the power when the market wanted it.

In the past two years we've made some pretty good moves. On the wholesale side, we've aligned our team and positioned ourselves to go nationwide. And with the passage of the holding company bill in Maryland, we will have the ability to finance this strategy.

Target

Wholesale Power Marketing and Generation

GAME PLAN:

- Market and trade power in the national wholesale arena.
- Assemble a strong portfolio of generating assets.
- Manage, operate and sell the output of generating plants.

STRATEGY:

Be a leader in wholesale power marketing and generation in North America.

Constellation Power Source in the Running

In a strategic move to realize the benefits of deregulation, BGE added Constellation Power Source to its roster of subsidiaries in 1997. With Goldman Sachs Power as its exclusive advisor, Constellation Power Source provides power-marketing and risk-management services to wholesale energy customers throughout North America.

Pairing BGE's electric industry expertise with Goldman Sachs' trading and risk-management expertise has its advantages. In less than two years, the business went from a standing start to one of the top 25 power marketers in the country. In 1998, trading volume increased nearly 12-fold to 116 million megawatt hours versus 9 million in 1997.

BGE's trading arm made money in 1998, a rare feat for any newcomer, especially in a highly competitive business like this one.

As evidenced by the volatile wholesale price swings this summer that had electricity selling for as high as $7,000 per megawatt hour, the market will continue to change. But it will reward those companies that best understand the dynamics that are at work. We believe Constellation Power Source has what it takes to succeed.

Gaining the Technological Edge From the new trading floor overlooking Baltimore's Inner Harbor, Constellation Power Source's nearly 100 employees have a real competitive advantage as they trade energy in North America. That's because they have access to first-rate technology with appropriate risk-management infrastructure in place.

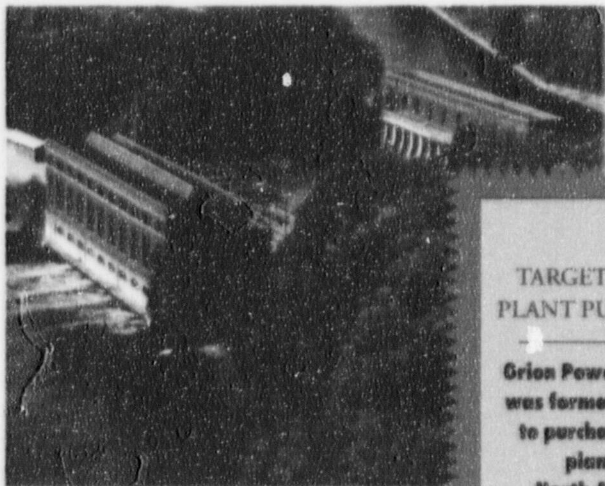
Constellation Power Source has customized for energy the same trading and risk-management system that Goldman Sachs uses to manage its worldwide commodities business. The result is an unparalleled information resource that supplies real-time details on trade positions and associated risks.

Orion Power Deals

Building on its power play, Constellation Power Source and an affiliate of Goldman, Sachs & Co. formed Orion Power Holdings, Inc. this year to pursue buying existing


TARGET AGGRESSIVE GROWTH IN WHOLESALE POWER MARKETING AND GENERATION
We have all the skills and services necessary to be a major contender in North America.

power plants in the United States and Canada. In 1998, Orion acquired the 105-megawatt Carr Street electric generating plant in upstate New York. It also announced the planned acquisition of New York State utility Niagara Mohawk's 72 hydro generating facilities totaling 661 megawatts of capacity.



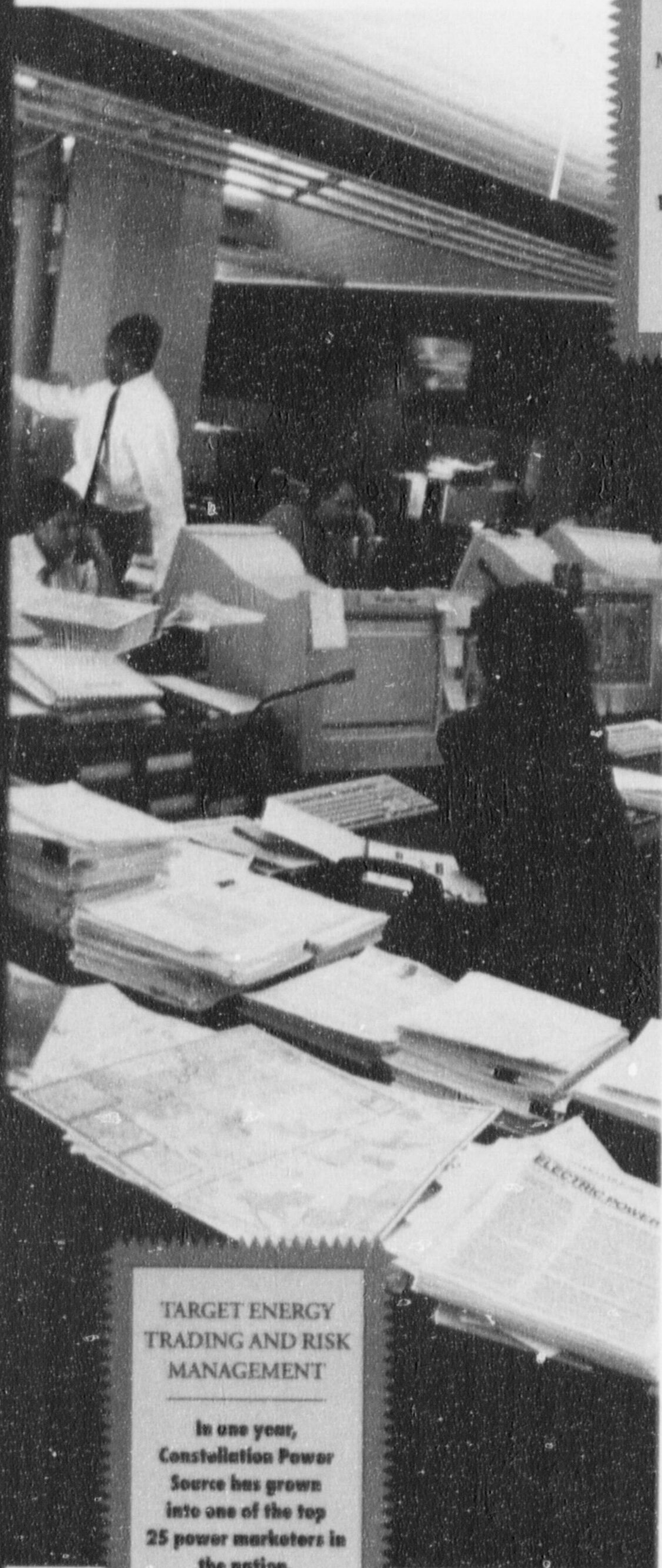
TARGET POWER PLANT PURCHASES

Orion Power Holdings was formed this year to purchase power plants in North America.

Our Orion investments provide benefits on several fronts. First, Orion's power plants will be operated by our Constellation Operating Services—a move that increases our power plant operating services business. And, Constellation Power Source has the exclusive right to market the output from Orion plants.

For example, Constellation Power Source entered into a five-year contract to purchase all of the capacity, energy, and ancillary services generated by Orion's Carr Street Generating Station LP. Constellation Operating Services will manage that plant.

Growing Business Base Constellation Power Source made its move this year to establish a base in New England, one of the first regions to go through the deregulation process. In 1998, Constellation Power Source entered into long-term contracts with Granite State Electric Company, Fitchburg Gas and Electric Company, and Eastern Utilities Associates. These contracts mean Constellation Power Source will provide wholesale electricity to these local utilities' customers who have not yet chosen a new electric supplier.



TARGET MERCHANT PLANT CONSTRUCTION

Constellation Power has more than 12 years experience in developing independent power plants.

Constellation Power Spearheads Merchant Plant Construction

While Orion concentrates on buying existing power plants to back our trading business, Constellation Power's focus is now turning to develop, build and operate merchant power plants in strategic regions.

The process to build a plant is a long one—usually two years for permitting and two years for construction. But the final product is a large, highly efficient generation facility whose full capacity can be sold on the wholesale market.

Seven Merchant Plant Site Approvals Under Way

Constellation Power has more than 12 years of experience developing independent power plants. Its understanding of the many project factors that need to be considered is invaluable.

As of this writing, Constellation Power is pursuing site approvals for several domestic merchant plant development projects. They include two sites in California suitable for 750 megawatts of electricity; two sites in Texas suitable for 1,600 megawatts; two sites in Florida suitable for 1,550 megawatts; and one in Massachusetts suitable for 700 megawatts.

What makes these sites so attractive is that they will be developed to provide power during the times of highest demand. They are also strategically located relative to major transmission systems, cooling water, and natural gas supply.

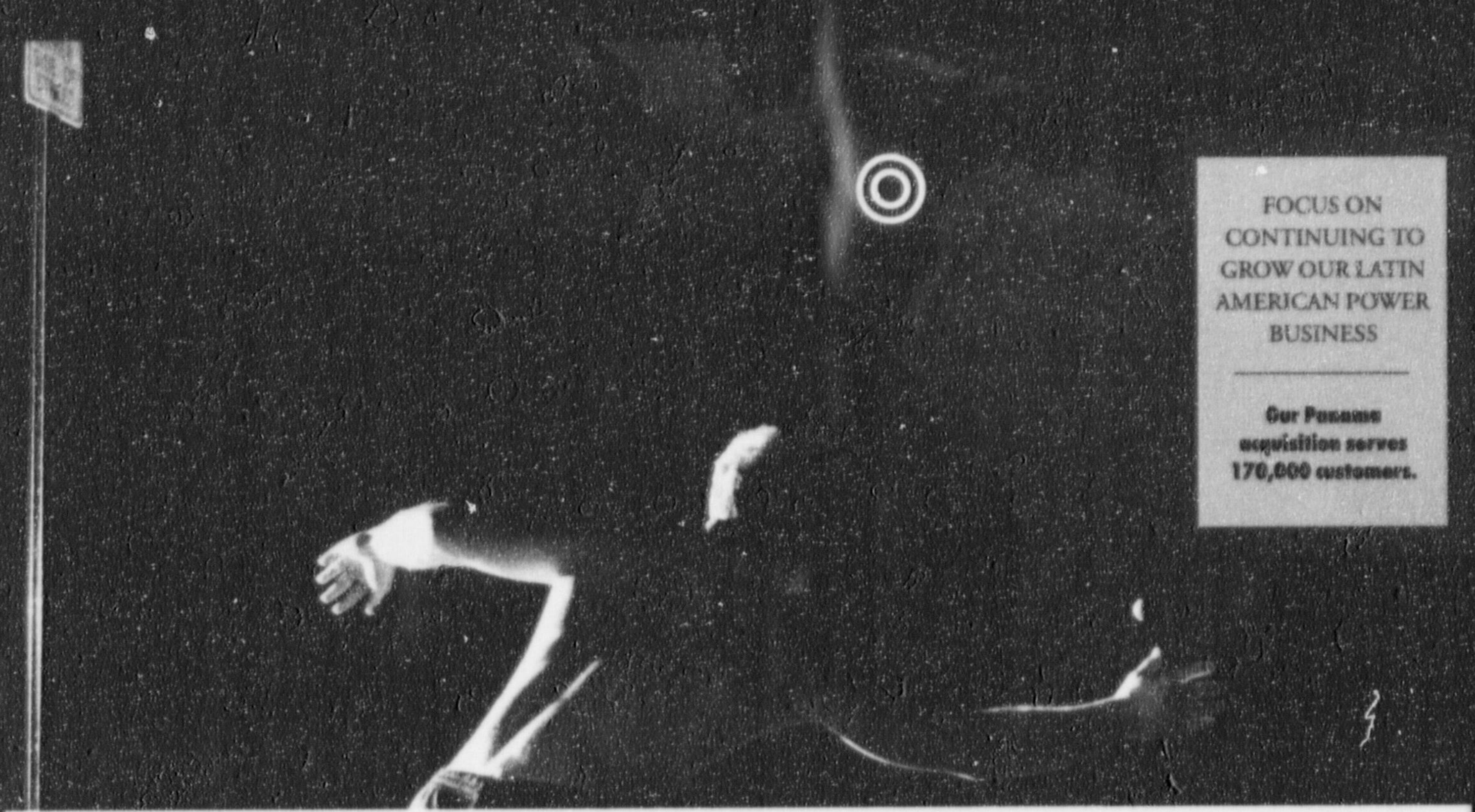
Building on Our Strengths

Between our Constellation Power Source, Constellation Power, and Constellation Operating Services businesses, we have assembled a contender in the merchant generation and power-marketing business. We have the know-how to build, buy and operate power plants, trade the output on the open market, and manage the risk of fluctuating energy prices.

The result? A new future for our company, our employees, and our shareholders—a future we're aggressively building on all fronts.

TARGET ENERGY TRADING AND RISK MANAGEMENT

In one year, Constellation Power Source has grown into one of the top 25 power marketers in the nation.



FOCUS ON CONTINUING TO GROW OUR LATIN AMERICAN POWER BUSINESS

Our Panama acquisition serves 170,000 customers.

Latin American utilities, once the domain of governments, are being privatized in an effort to more efficiently serve the regions' growing demand for electricity. The governments have turned to foreign investors with energy experience, an invitation that has allowed us to expand our expertise beyond U.S. borders.

Currently, through our Constellation Power affiliate, we have interests in 15 projects in eight Latin American countries including Argentina, Bolivia, Brazil, Costa Rica, El Salvador, Guatemala, Panama, and Peru.

Elektra Noreste-Panama Most recently, we acquired the controlling interest in Elektra Noreste, S.A., which serves the eastern half of Panama. It's our biggest acquisition ever and the first time we have taken control of a distribution company. The second-largest electric distribution company in Panama, Elektra Noreste serves 170,000 customers. We plan to improve performance and service to these customers and grow this distribution company.

GAME PLAN:

- Acquire generation and distribution assets.
- Leverage our experience and expertise.
- Form solid partnerships.

Focus
on Latin America

STRATEGY:

Be a significant generation and energy delivery supplier in Latin America.

Generating in Guatemala Similarly, Constellation Power has plans to expand the generating capacity we purchased in Guatemala. Again, the goal is to fulfill our supply agreements and have merchant power available to sell in the area as demand accelerates. We have already added 60 megawatts of new generation here and did so in record time. We closed on the Guatemala acquisition in January 1998 and by August—just seven months later—we had new capacity online.

Good Timing We arrived on the scene at a fortuitous time, and our success so far has been gratifying. Over the last three years we have bid on six major privatizations and won four of them. The competition has been stiff, often involving much larger international corporations. Nonetheless, we intend to build on our winning track record and increase our involvement in the privatization process in the future.

FINANCIAL CONTENTS

Utility Operating Statistics

Baltimore Gas and Electric Company and Subsidiaries

	1998	1997	1996	1995	1994	Compound Growth 5-Year	Compound Growth 10-Year
Electric Operating Statistics							
Revenues *(In Millions)*							
Residential	$ 948.6	$ 932.5	$ 958.7	$ 955.2	$ 931.7	0.36%	4.33%
Commercial	912.9	892.6	861.3	879.4	853.0	0.97	3.82
Industrial	211.5	211.9	207.6	208.5	205.6	1.23	1.77
System Sales	2,073.0	2,037.0	2,027.6	2,043.1	1,990.3	0.71	3.81
Interchange and Other Sales	120.8	132.7	155.9	167.0	118.0	5.71	10.65
Other	27.0	22.3	25.5	21.0	19.1	6.08	1.84
Total	$2,220.8	$2,192.0	$2,209.0	$2,231.1	$2,127.4	1.01	4.06
Sales *(In Thousands)*—MWH							
Residential	10,965	10,806	11,243	10,966	10,670	0.65	1.77
Commercial	13,219	12,718	12,591	12,635	12,351	1.30	2.20
Industrial	4,583	4,575	4,596	4,591	4,433	4.02	1.00
System Sales	28,767	28,099	28,430	28,192	27,454	1.45	1.84
Interchange and Other Sales	5,454	6,224	7,580	8,149	5,684	5.62	10.27
Total	34,221	34,323	36,010	36,341	33,138	2.05	2.77
Customers *(In Thousands)*							
Residential	1,009.1	1,001.0	995.2	988.2	978.6	0.83	1.20
Commercial	106.5	105.9	104.5	103.4	101.9	1.11	1.41
Industrial	4.6	4.5	4.3	4.1	4.0	3.90	5.87
Total	1,120.2	1,111.4	1,104.0	1,095.7	1,084.5	0.87	1.23
Average Use per Residential Customer—KWH	10,866	10,794	11,297	11,097	10,903	(0.18)	0.57
Average Rate per KWH (System Sales)—¢							
Residential	8.65	8.63	8.53	8.71	8.73	(0.30)	2.51
Commercial	6.91	7.02	6.84	6.96	6.91	(0.32)	1.59
Industrial	4.62	4.63	4.52	4.54	4.64	(2.67)	0.77
Peak Load (One-Hour)—MW	6,045	5,980	5,955	5,947	6,038	0.57	1.17
Capability at Summer Peak—MW	6,422	6,741	6,800	6,731	6,722	(0.85)	0.80
System Load Factor	57.4%	56.9%	57.5%	57.2%	54.7%	0.78	0.50
Gas Operating Statistics							
Revenues *(In Millions)*							
Residential —Excluding Delivery Service	$ 279.2	$ 321.7	$ 320.1	$ 248.3	$ 262.7	1.00	2.18
—Delivery Service	4.9	0.5	—	—	—	—	—
Commercial —Excluding Delivery Service	75.6	113.5	125.1	109.9	121.0	(9.10)	(3.27)
—Delivery Service	19.4	12.9	7.2	3.7	2.3	42.51	21.80
Industrial —Excluding Delivery Service	8.0	11.4	17.1	16.7	20.2	(18.54)	(10.29)
—Delivery Service	16.0	17.2	14.6	16.3	9.6	4.40	(0.37)
System Sales	403.1	477.2	484.1	394.9	415.8	(1.09)	0.77
Off-System Sales	40.9	37.5	26.6	—	—	—	—
Other	7.2	6.9	6.6	5.6	5.4	(0.28)	(1.29)
Total	$ 451.2	$ 521.6	$ 517.3	$ 400.5	$ 421.2	0.82	1.69
Sales *(In Thousands)*—DTH							
Residential —Excluding Delivery Service	33,595	39,958	43,784	40,211	40,279	(3.44)	(1.76)
—Delivery Service	1,890	205	—	—	—	—	—
Commercial —Excluding Delivery Service	11,775	18,435	22,698	23,612	23,712	(13.15)	(6.37)
—Delivery Service	16,633	12,964	8,755	6,982	6,490	17.50	12.72
Industrial —Excluding Delivery Service	1,412	2,016	2,887	4,102	4,410	(23.24)	(13.21)
—Delivery Service	34,798	38,791	36,201	35,925	33,837	2.08	(0.28)
System Sales	100,103	112,369	114,325	110,832	108,728	(1.50)	(0.90)
Off-System Sales	16,724	14,759	9,968	—	—	—	—
Total	116,827	127,128	124,293	110,832	108,728	1.59	0.65
Customers *(In Thousands)*							
Residential	532.5	524.5	516.5	506.8	498.2	1.63	1.00
Commercial	39.6	39.3	38.9	38.4	37.9	1.10	1.13
Industrial	1.3	1.3	1.3	1.3	1.3	—	—
Total	573.4	565.1	556.7	546.5	537.4	1.59	1.01
Average Use per Residential Customer (Excluding Delivery Service)—Therms	631	762	848	794	809	(4.99)	(2.74)
Average Rate per Therm—$							
Residential (Excluding Delivery Service)	.83	.81	.73	.62	.65	4.69	4.01
Commercial (Excluding Delivery Service)	.64	.62	.55	.47	.51	4.65	3.36
Industrial (Excluding Delivery Service)	.57	.57	.59	.41	.46	6.30	3.35
Peak Day Sendout *(In Thousands)*—DTH	658.4	765.0	709.0	706.3	761.9	0.02	(0.17)
Peak Day Capability *(In Thousands)*—DTH	833.0	870.0	870.0	847.0	847.0	(0.33)	0.49

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

Selected Financial Data

Baltimore Gas and Electric Company and Subsidiaries

	1998	1997	1996	1995	1994	Compound Growth 5-Year	Compound Growth 10-Year
	(Dollar amounts in millions, except per share amounts)						
Summary of Operations							
Total Revenues	$3,358.1	$3,307.6	$3,153.2	$2,934.8	$2,783.0	4.14%	5.37%
Expenses Other Than Interest and Income Taxes	2,617.0	2,584.0	2,483.7	2,239.1	2,147.7	4.25	5.81
Income From Operations	741.1	723.6	669.5	695.7	635.3	3.75	3.98
Other Income (Expense)	5.7	(52.8)	6.1	8.8	32.3	(22.43)	(11.20)
Income Before Interest and Income Taxes	746.8	670.8	675.6	704.5	667.6	3.24	3.68
Net Interest Expense	240.9	230.0	198.5	197.0	190.1	4.99	6.87
Income Before Income Taxes	505.9	440.8	477.1	507.5	477.5	2.47	2.47
Income Taxes	178.2	158.0	166.3	169.5	153.9	5.23	6.71
Net Income	327.7	282.8	310.8	338.0	323.6	1.13	0.77
Preferred and Preference Stock Dividends	21.8	28.7	38.5	40.6	39.9	(12.21)	(2.95)
Earnings Applicable to Common Stock	$ 305.9	$ 254.1	$ 272.3	$ 297.4	$ 283.7	2.68	1.11
Earnings Per Share of Common Stock and Earnings Per Share of Common Stock—Assuming Dilution	$ 2.06	$ 1.72	$ 1.85	$ 2.02	$ 1.93	2.17	(1.14)
Dividends Declared Per Share of Common Stock	$ 1.67	$ 1.63	$ 1.59	$ 1.55	$ 1.51	2.58	2.38
Summary of Financial Condition							
Total Assets	$9,195.0	$8,900.0	$8,678.2	$8,419.1	$8,145.3	2.86	6.02
Capitalization							
Long-term debt	$3,128.1	$2,988.9	$2,758.8	$2,598.2	$2,584.9	2.07	5.87
Preferred stock	—	—	—	59.2	59.2	—	—
Redeemable preference stock	—	90.0	134.5	242.0	279.5	—	—
Preference stock not subject to mandatory redemption	190.0	210.0	210.0	210.0	150.0	4.84	6.63
Common shareholders' equity	2,981.5	2,870.4	2,854.7	2,811.2	2,719.0	2.61	4.69
Total Capitalization	$6,299.6	$6,159.3	$5,958.0	$5,920.6	$5,792.6	1.00	4.51
Financial Statistics at Year End							
Ratio of Earnings to Fixed Charges	2.94	2.78	3.10	3.21	3.14		
Ratio of Earnings to Combined Fixed Charges and Preferred and Preference Stock Dividends	2.60	2.35	2.44	2.52	2.47		
Book Value Per Share of Common Stock	$ 19.98	$ 19.44	$ 19.33	$ 19.06	$ 18.43		
Number of Common Shareholders *(In Thousands)*	69.9	73.7	77.6	79.8	81.5		

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

Management's Discussion and Analysis

of Financial Condition and Results of Operations

Introduction

In Management's Discussion and Analysis, we explain the general financial condition and the results of operations for BGE® and its diversified business subsidiaries including:

- what factors affect our businesses,
- what our earnings and costs were in 1998 and 1997,
- why earnings and costs changed from the year before,
- where our earnings came from,
- how all of this affects our overall financial condition,
- what our expenditures for capital projects were in 1996 through 1998, and what we expect them to be in 1999 through 2001, and
- where we will get cash for future capital expenditures.

As you read Management's Discussion and Analysis, it may be helpful to refer to our Consolidated Statements of Income on page 37 which present the results of our operations for 1998, 1997, and 1996. In Management's Discussion and Analysis, we analyze and explain the annual changes in the specific line items in the Consolidated Statements of Income.

The electric utility industry is undergoing rapid and substantial change. Competition in the generation part of our business is increasing. The regulatory environment (federal and state) is shifting toward customer choice. These matters are discussed briefly in the "Competition and Response to Regulatory Change" section beginning on page 22. They are discussed in detail in our most recent Annual Report on Form 10-K.

In response to this change, we regularly reevaluate our strategies with two goals in mind: to improve our competitive position, and to anticipate and adapt to regulatory change. These strategies might include one or more of the following:

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

We cannot predict whether any of the strategies described above may actually occur, or what their effect on our financial condition or competitive position might be. Please refer to the "Forward Looking Statements" section on page 35.

Results of Operations

In this section, we discuss our earnings and the factors affecting them. We begin with a general overview, then separately discuss earnings for the utility business and for diversified businesses.

Overview

Total Earnings per Share of Common Stock

	1998	1997	1996
Utility business	$1.93	$1.94	$1.96
Diversified businesses (subsidiaries)	.27	.34	.31
Total earnings per share from operations	2.20	2.28	2.27
Write-off of merger costs (see Note 2 on page 51)	—	(.25)	—
Write-downs of real estate investments (see Note 3 on page 52)	(.10)	(.31)	—
Disallowed replacement energy costs (see Note 10 on page 63)	—	—	(.42)
Write-off of energy services investment (see Note 2 on page 51)	(.04)	—	—
Total earnings per share	$2.06	$1.72	$1.85

1998

Our 1998 total earnings increased $51.8 million, or $.34 per share, compared to 1997. Our total earnings increased mostly because 1997 results reflect our write-off of merger costs, and our real estate and senior-living facilities business' write-down of its investments in two real estate projects, as discussed in the 1997 section below. Our 1998 earnings would have been higher except:

- our real estate and senior-living facilities business wrote down its investment in a real estate project, and
- we wrote off an energy services investment.

In 1998, utility earnings from operations were about the same compared to 1997. We discuss our utility earnings in more detail in the "Utility Business" section beginning on page 21.

In 1998, diversified business earnings from operations decreased compared to 1997 mostly because of lower earnings from our real estate and senior-living facilities and financial investments businesses. However, we had higher earnings from our power projects and power marketing and trading businesses. We discuss our diversified business earnings in more detail in the "Diversified Businesses" section beginning on page 26.

We discuss the real estate write-down in the "Other Diversified Businesses" section on page 28 and the write-off of the energy services investment in the "Other Energy Services" section on page 28.

1997

Our 1997 total earnings decreased $18.2 million, or $.13 per share, compared to 1996. Our total earnings decreased because:

- we wrote off costs associated with the terminated merger with Potomac Electric Power Company, and
- our real estate and senior-living facilities business wrote down its investments in two real estate projects.

We discuss the write-off of merger costs in the "Write-Off of Merger Costs" section on page 26, and the real estate write-downs in the "Other Diversified Businesses" section on page 28.

In 1997, utility earnings from operations decreased compared to 1996 mostly because we sold less electricity and gas due to milder weather.

In 1997, diversified business earnings from operations increased compared to 1996 mostly because of higher earnings from our power projects and financial investments businesses.

Utility Business

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

Regulation by the Maryland Public Service Commission (Maryland PSC)

The Maryland PSC determines the rates we can charge our customers. Our rates consist of a "base rate" and a "fuel rate." The base rate is the rate the Maryland PSC allows us to charge our customers for the cost of providing them service, plus a profit. We have both an electric base rate and a gas base rate. Higher electric base rates apply during the summer when the demand for electricity is the highest. Gas base rates are not affected by seasonal changes.

The Maryland PSC allows us to include in base rates a component to recover money spent on conservation programs. This component is called a "conservation surcharge." However, under this surcharge the Maryland PSC limits what our profit can be. If, at the end of the year, we have exceeded our allowed profit, we defer the excess in that year and we lower the amount of future surcharges to our customers to correct the amount of overage, plus interest.

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

We discuss this in more detail in the "Electric Fuel Rate Clause" section on page 24 and in Note 1 of the Notes to Consolidated Financial Statements on page 46.

Changes in the fuel rate normally do not affect earnings. However, if the Maryland PSC disallows recovery of any part of the fuel costs, our earnings are reduced. In 1996, the Maryland PSC disallowed certain fuel costs as discussed in the "Disallowed Replacement Energy Costs" section on page 24 and in Note 10 on page 63.

We also charge our gas customers separately for the natural gas they purchase from us. The price we charge for the natural gas is based on a market based rates incentive mechanism approved by the Maryland PSC. We discuss market based rates in more detail in the "Gas Cost Adjustments" section on page 25 and in Note 1 on page 46.

From time to time, when necessary to cover increased costs, we ask the Maryland PSC for base rate increases. The Maryland PSC holds hearings to determine whether to grant us all or a portion of the amount requested. The Maryland PSC historically has allowed us to increase base rates to recover increased utility plant asset costs, plus a profit, beginning at the time of replacement. Generally, rate increases improve our utility earnings because they allow us to collect more revenue. However, rate increases are normally granted based on historical data, and those increases may not always keep pace with increasing costs.

Other parties may petition the Maryland PSC to lower our base rates. We discuss this in more detail in the "Competition and Response to Regulatory Change" section on page 22.

Weather

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

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

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

Effective March 1, 1998, the Maryland PSC allowed us to implement a monthly adjustment to our gas business revenues to eliminate the effect of abnormal weather patterns. We discuss this further in the "Weather Normalization" section on page 25.

We show the number of cooling and heating degree days in 1998 and 1997, the percentage changes in the number of degree days from the prior year, and the number of degree days in a "normal" year as represented by the 30-year average in the following table.

	1998	1997	30-year average
Cooling degree days	915	746	836
Percentage change from prior year	22.7%	(5.1)%	
Heating degree days	4,119	4,822	4,783
Percentage change from prior year	(14.6)%	(6.2)%	

Other Factors

Other factors, aside from weather, impact the demand for electricity and gas. These factors include the "number of customers" and "usage per customer" during a given period. We use these terms later in our discussions of electric and gas operations. In those sections, we discuss how these and other factors affected electric and gas sales during 1998 and 1997.

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 which 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.

Competition and Response to Regulatory Change

Our electric and gas businesses are also affected by competition and regulatory changes. We discuss these items for both of our regulated businesses below.

Electric Business

Electric utilities are facing competition on various fronts, including:

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

On July 1, 1998, BGE and all other Maryland investor-owned electric utilities filed with the Maryland PSC their individual proposals for the transition from a regulated electric supply system to one where generation is priced based on a competitive retail electric market. In our plan, we proposed that:

- all customers would be able to choose other suppliers or our service,
- we would guarantee our service at rates frozen until July 2002. Prices would then be adjusted for inflation until the transition is complete, but not beyond 2008,
- customers who choose an alternate supplier would receive a shopping credit. This credit would reduce their BGE bill by the market value of capacity, energy, and other services that we no longer provide those customers,
- we would attempt to reduce potentially stranded investments by lowering operating costs and applying all earnings in excess of our authorized rate of return to accelerate the recovery of generation assets. This would lower the generation asset book values toward their competitive market values thereby reducing any potentially stranded investment,
- market value of generation assets would be determined by annual independent appraisals beginning in 2002 and continuing through the transition period,
- when the difference between the book value and market value of generation assets is within 10%, the transition period would end and a non-bypassable surcharge would be applied to customers' bills to recover the remaining stranded investments over a two- to three-year period, and
- net regulatory assets and nuclear decommissioning costs would continue to be collected from customers through the regulated transmission and distribution business.

On December 22, 1998, other parties filed their positions in response to our proposal. The counter-proposals contain provisions which, if adopted by the Maryland PSC, could negatively impact our electric business. The Maryland PSC will hold hearings to examine our electric restructuring transition proposal and the counter-proposals of other parties. In the meantime, settlement negotiations are ongoing. Absent settlement, the Maryland PSC is scheduled to issue an order by October 1, 1999.

On September 3, 1998, the Office of People's Counsel (OPC) filed a petition requesting the Maryland PSC to lower our electric base rates. At our request, the Maryland PSC agreed to consolidate any such review of our electric base rates with its review of our electric restructuring transition proposal discussed above. We filed testimony and exhibits with the Maryland PSC supporting our position that our current electric base rates are justified. On February 5, 1999, other parties, including the OPC, filed testimonies to lower our base rates by as much as $131 million. As a condition of the Maryland PSC's consolidation of these matters, we agreed to make our rates subject to refund effective July 1, 1999 should the Maryland PSC issue a rate reduction order after that date.

We cannot predict the ultimate effect competition or regulatory change will have on our earnings.

We discuss competition in our electric business in more detail in our most recent Annual Report on Form 10-K under the heading "Electric Regulatory Matters and Competition."

Gas Business

Regulatory change in the natural gas industry is well under way. We discuss competition in our gas business in more detail in our most recent Annual Report on Form 10-K under the heading "Gas Regulatory Matters and Competition."

Effective November 1, 1998, the Maryland PSC allowed us to begin collecting a Delivery Service Realignment Charge to recover certain costs associated with the introduction of competition in our gas business. This is not expected to significantly impact our earnings.

Utility

Business Earnings per Share of Common Stock

	1998	1997	1996
Electric business	$1.75	$1.77	$1.75
Gas business	.18	.17	.21
Total utility earnings per share from operations	1.93	1.94	1.96
Write-off of merger costs (see Note 2 on page 51)	—	(.25)	—
Disallowed replacement energy costs (see Note 10 on page 63)	—	—	(.42)
Total utility earnings per share	$1.93	$1.69	$1.54

Utility Business Earnings per Share of Common Stock

Our 1998 total utility earnings increased $36.1 million, or $.24 per share, from 1997. Our 1997 total utility earnings increased $24.0 million, or $.15 per share, from 1996. We discuss the factors affecting utility earnings below.

Electric Operations

Electric Revenues

The changes in electric revenues in 1998 and 1997 compared to the respective prior year were caused by:

	1998	1997
	(In millions)	
Electric system sales volumes	$50.8	$(15.5)
Base rates	(6.6)	29.2
Fuel rates	(8.1)	(4.3)
Total change in electric revenues from electric system sales	36.1	9.4
Interchange and other sales	(13.2)	(23.2)
Other	4.6	(3.2)
Total change in electric revenues	$27.5	$(17.0)

Electric System Sales Volumes

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

The percentage changes in our electric system sales volumes, by type of customer, in 1998 and 1997 compared to the respective prior year were:

	1998	1997
Residential	1.5%	(3.9)%
Commercial	3.9	1.0
Industrial	0.2	(0.4)

In 1998, we sold more electricity to residential customers mostly because:

- the number of customers increased,
- we had hotter summer weather, and
- usage per customer increased.

We would have sold even more electricity to residential customers except we had milder winter weather in 1998. We sold more electricity to commercial customers mostly because usage per customer increased. We sold about the same amount of electricity to industrial customers as we did in 1997.

In 1997, we sold less electricity to residential customers mostly for two reasons: lower usage per customer and milder weather. We sold more electricity to commercial customers mostly because usage per customer increased. We would have sold even more electricity to commercial customers except for milder weather during the year. We sold about the same amount of electricity to industrial customers as we did in 1996.

Base Rates

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

In 1997, base rate revenues increased compared to 1996 because of higher conservation surcharge revenues. During 1996, we exceeded our profit limit under the conservation surcharge. As a result, we excluded $28.5 million of our 1996 surcharge billings from revenue. To correct the overage, we lowered the surcharge on our customers' bills over a twelve-month period beginning July 1997 through June 1998.

Fuel Rates

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

In 1997, fuel rate revenues decreased compared to 1996 mostly because we sold less electricity.

Interchange and Other Sales

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

In 1998 and 1997, interchange and other sales revenues decreased compared to the respective prior year mostly because of lower sales volumes.

Electric Fuel and Purchased Energy Expenses

	1998	1997	1996
		(In millions)	
Actual costs	\$514.7	\$504.5	\$539.2
Net recovery (deferral) of costs under electric fuel rate clause (see Note 1 on page 46)	(9.0)	15.2	8.2
Disallowed replacement energy costs (including carrying charges) (see Note 10 on page 63)	—	—	95.4
Total electric fuel and purchased energy expenses	\$505.7	\$519.7	\$642.8

Actual Costs

In 1998, our actual costs of fuel to generate electricity (nuclear fuel, coal, gas, or oil) and electricity we bought from others increased compared to 1997 mostly because we settled a capacity contract with PECO Energy Company.

In 1997, our actual costs decreased compared to 1996 mostly for two reasons: we bought less electricity from others as a result of being able to meet demand using the electricity we generated, and we were able to use a less-costly mix of generating plants mostly because we generated more electricity at Calvert Cliffs.

Electric Fuel Rate Clause

Under the electric fuel rate clause, we defer (include as an asset or liability in our Consolidated Balance Sheets and exclude from our Consolidated Statements of Income) the difference between our actual costs of fuel and energy and what we collect from customers under the fuel rate in a given period. We either bill or refund our customers that difference in the future. We discuss the calculation of the fuel rate in Note 1 on page 46.

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

In 1997, our actual costs of fuel and energy were lower than the fuel rate revenues we collected from our customers.

Disallowed Replacement Energy Costs

In December 1996, we settled fuel rate proceedings about extended outages that occurred at Calvert Cliffs from 1989 through 1991. We agreed not to bill our customers for \$118 million of electric replacement energy costs associated with the outages. We wrote off a portion of the costs in 1990 and wrote off the remainder in 1996. We discuss this further in Note 10 on page 63.

Gas Operations

Gas Revenues

The changes in gas revenues in 1998 and 1997 compared to the respective prior year were caused by:

	1998	1997
	(In millions)	
Gas system sales volumes	\$(10.8)	\$(7.3)
Base rates	14.2	0.6
Weather normalization	10.1	—
Gas cost adjustments	(87.6)	(0.2)
Total change in gas revenues from gas system sales	(74.1)	(6.9)
Off-system sales	1.8	10.9
Other	0.1	0.3
Total change in gas revenues	\$(72.2)	\$ 4.3

Gas System Sales Volumes

The percentage changes in our gas system sales volumes, by type of customer, in 1998 and 1997 compared to the respective prior year were:

	1998	1997
Residential	(11.6)%	(8.3)%
Commercial	(9.5)	(0.2)
Industrial	(11.3)	4.4

In 1998, we sold less gas to residential and commercial customers mostly for two reasons: milder weather and lower usage per customer. We would have sold even less gas to residential and commercial customers except the number of customers increased. We sold less gas to industrial customers mostly because usage by Bethlehem Steel (our largest customer) and other industrial customers decreased.

In 1997, we sold less gas to residential customers mostly for two reasons: lower usage per customer and milder weather. We sold about the same amount of gas to commercial customers as we did in 1996. We sold more gas to industrial customers mostly for two reasons: milder weather caused fewer service interruptions and Bethlehem Steel used more gas. Sometimes we need to interrupt service during periods with the highest demand. Some industrial customers pay reduced rates in exchange for our right to interrupt their service during these periods. We would have sold even more gas to industrial customers except gas usage by industrial customers other than Bethlehem Steel decreased.

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

In 1997, base rate revenues increased compared to 1996. Although we sold less gas in 1997, our base rate revenues increased because of higher conservation surcharge revenues during the last six months of the year.

Weather Normalization
Effective March 1, 1998, the Maryland PSC allowed us to implement a monthly adjustment to our gas base rate revenues to eliminate the effect of abnormal weather patterns on our gas system sales volumes. This means our monthly gas base rate revenues will be based on weather that is considered "normal" for the month and, therefore, will not be affected by actual weather conditions.

Gas Cost Adjustments
We charge our gas customers for the natural gas they purchase from us using gas cost adjustment clauses set by the Maryland PSC. These clauses operate similar to the electric fuel rate clause described in the "Electric Fuel Rate Clause" section on page 24.

However, effective October 1996, the Maryland PSC approved a modification of these gas clauses to provide a market based rates incentive mechanism. Under market based rates, our actual cost of gas is compared to a market index (a measure of the market price of gas in a given period). The difference between our actual cost and the market index is shared equally between shareholders and customers, and does not significantly impact earnings. We also discuss this in Note 1 on page 46.

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

In 1998 and 1997, gas cost adjustment revenues decreased compared to the respective prior year mostly because we sold less gas.

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

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

In 1997, off-system gas sales revenues increased compared to 1996 mostly because we first began off-system sales of gas in February 1996.

Gas Purchased for Resale Expenses

	1998	1997	1996
		(In millions)	
Actual costs	**$212.2**	$291.6	$295.4
Net recovery (deferral) of costs under gas adjustment clauses (see Note 1 on page 46)	**(3.6)**	0.5	(11.0)
Total gas purchased for resale expenses	**$208.6**	$292.1	$284.4

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

In 1998 and 1997, actual gas costs decreased compared to the respective prior year mostly because we sold less gas.

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

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

In 1997, actual gas costs were lower than the revenues we collected from our customers.

Other Operating Expenses

Operations and Maintenance Expenses
In 1998, operations and maintenance expenses increased $34.8 million compared to 1997 mostly because of:

- higher nuclear costs,
- higher employee benefit costs, and
- a $6.0 million write-off of contributions to a third party for a low-level radiation waste facility that was never completed.

In 1997, operations and maintenance expenses were slightly lower than they were in 1996.

Depreciation and Amortization Expenses
We describe depreciation and amortization expenses in Note 1 on page 48.

In 1998, depreciation and amortization expenses increased $34.2 million compared to 1997 mostly because:

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

In 1997, depreciation and amortization expenses increased $12.7 million compared to 1996 mostly because we had more plant in service.

Other Income and Expenses

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

Interest Charges
Interest charges represent the interest on our outstanding debt.

In 1998, interest charges increased $6.7 million compared to 1997 mostly because we had more debt outstanding. Interest charges would have been higher except interest rates were lower than they were in 1997.

In 1997, interest charges increased $23.6 million compared to 1996 mostly for two reasons: we had more debt outstanding and interest rates were higher.

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

In 1997, income taxes decreased $8.3 million compared to 1996 because we had lower taxable income from both our utility operations and our diversified businesses.

Diversified Businesses

Our diversified businesses engage primarily in energy services. Our energy services businesses include certain subsidiaries of Constellation® Enterprises, Inc. and the District Chilled Water General Partnership (ComfortLink®), a general partnership in which BGE is a partner. They are:

- Constellation Power Source,™ Inc.—our wholesale power marketing and trading business,
- Constellation Power,™ Inc. and Subsidiaries—our power projects business,
- Constellation Energy Source,™ Inc.—our energy products and services business,
- BGE Home Products & Services,™ Inc. and Subsidiaries—our home products, commercial building systems, and residential and small commercial gas retail marketing business, and
- ComfortLink—our cooling services business for commercial customers in Baltimore.

Constellation Enterprises, Inc. also has two other subsidiaries:

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

We describe our diversified businesses in more detail in our most recent Annual Report on Form 10-K under Item 1. Business—Diversified Businesses.

Diversified Business Earnings per Share of Common Stock

Our 1998 diversified business earnings increased $15.7 million, or $.10 per share, compared to 1997. Our 1997 diversified business earnings decreased $42.2 million, or $.28 per share, compared to 1996.

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

Energy Services

Power Marketing and Trading

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

Constellation Power Source uses the mark-to-market method of accounting for its trading activities. We discuss the mark-to-market method of accounting and Constellation Power Source's trading activities in Note 1 on page 47.

Diversified
Business Earnings per Share of Common Stock

	1998	1997	1996
Energy services			
Power marketing and trading	$.05	$.00	$—
Power projects	.30	.25	.18
Other	(.01)	(.05)	.02
Total energy services earnings per share from operations	.34	.20	.20
Other diversified businesses earnings per share from operations	(.07)	.14	.11
Total diversified business earnings per share from operations	.27	.34	.31
Write-downs of real estate investments (see Note 3 on page 52)	(.10)	(.31)	—
Write-off of energy services investment	(.04)	—	—
Total earnings per share	$.13	$.03	$.31

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

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

Constellation Power Source's management uses its best estimates to determine the fair value of commodity and derivative positions it holds and sells. These estimates consider various factors including closing exchange and over-the-counter price quotations, time value, volatility factors, and credit exposure. However, it is possible that future market prices could vary from those used in recording assets and liabilities from trading activities, and such variations could be material. In 1998, assets and liabilities from energy trading activities increased because of greater trading activity compared to 1997.

In March 1998, Constellation Power Source and Goldman, Sachs Capital Partners II L.P., an affiliate of Goldman, Sachs & Co., formed Orion Power Holdings, Inc. (Orion) to acquire electric generating plants in the United States and Canada. Constellation Power Source has a commitment to fund its investment in Orion as discussed further in Note 10 on page 61.

Power Projects

In 1998, earnings from our power projects business increased compared to 1997 mostly because Constellation Power recorded a $10.4 million after-tax gain for its share of earnings in a partnership. The partnership recognized a gain on the sale of its ownership interest in a power sales contract.

In 1997, earnings increased compared to 1996 mostly because of improved performance of various energy projects. Also, 1996 earnings included $14.6 million (after-tax) for Constellation Power's percentage share of earnings in a partnership. The partnership recognized a gain on the sale of a power purchase agreement. These increases were offset by $16.2 million of after-tax write-offs of investments in certain power projects.

We describe our earnings in the partnerships and the write-offs further in Note 3 on page 52.

California Power Purchase Agreements

Constellation Power and subsidiaries and Constellation Investments have $310.6 million invested in 15 projects that sell electricity in California under power purchase agreements called "Interim Standard Offer No. 4" agreements. In 1998, earnings from these projects were $41.3 million, or $.28 per share.

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

Our power projects business is pursuing alternatives for some of these projects including:

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

The California projects that make the highest revenues will transition in 1999 and 2000. The projects which transition in 1999 contributed $10.7 million, or $.07 per share to 1998 earnings, while those changing over in 2000 contributed $24.0 million, or $.16 per share to 1998 earnings. We expect earnings to ultimately decrease by similar amounts beginning in 1999 as these projects transition.

We describe these projects in more detail in Note 10 on page 63.

International Projects

At December 31, 1998, Constellation Power had invested about $183.4 million in 15 power projects in Latin America compared to $23.5 million invested in Latin America in 1997. These investments include:

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

In the future, Constellation Power expects to expand its power projects business further in both domestic and international projects.

Other Energy Services

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

In 1997, earnings from our remaining energy services businesses decreased compared to 1996 mostly because of lower earnings from our energy products and services business.

Other Diversified Businesses

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

- a $15.4 million after-tax write-down of its investment in Church Street Station—an entertainment, dining, and retail complex in Orlando, Florida,
- lower earnings from various real estate and senior-living facilities projects, and
- a $4 million after-tax gain on the sale of two senior-living facilities projects reflected in 1997 results.

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

Earnings from our financial investments business decreased compared to 1997 mostly because of:

- better market performance for our investments in 1997, and
- a $6 million after-tax gain on the sale of stock held by a financial limited partnership reflected in 1997 results.

In 1997, earnings from our other diversified businesses increased compared to 1996 mostly because of increased earnings in our financial investments business from better earnings in trading securities and increased gains from marketable securities. Earnings would have been higher except we had a decrease in earnings from our real estate and senior-living facilities business mostly due to:

- a $14.1 million after-tax write-down of the investment in Church Street Station, and
- a $31.9 million after-tax write-down of the investment in Piney Orchard—a mixed-use, planned-unit development.

We discuss our real estate projects, the write-downs of our real estate projects, the COPT transaction, and our financial investments further in Note 3 on page 52.

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

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

Financial Condition

Cash Flows

	1998	1997	1996
		(In millions)	
Cash provided by (used in):			
Operating Activities	$820.8	$726.0	$701.9
Investing Activities	(625.0)	(520.8)	(567.0)
Financing Activities	(184.7)	(109.3)	(91.6)

In 1998 and 1997, cash provided by operations increased compared to the respective prior year mostly because of changes in working capital requirements.

In 1998, net cash used in investing activities increased compared to 1997 mostly because of the additional investment in international power projects. Cash used in investing would have been higher except for a $33.8 million decrease in utility construction expenditures.

In 1997, net cash used in investing activities decreased mostly because of the $79.5 million cash inflow from the sale of real estate properties and the increase in loans collected from real estate projects compared to 1996. Cash used in investing activities would have been lower except for a $12.7 million increase in utility construction expenditures, and $46.5 million increase for our investments in power projects and financial limited partnerships.

Total utility construction expenditures, including the allowance for funds used during construction, were $339.4 million in 1998 as compared to $373.2 million in 1997 and $360.5 million in 1996.

In 1998, cash used in financing activities increased compared to 1997 mostly because of the repayment of short-term borrowings that matured, sinking fund requirements, and early redemption of higher cost securities. Net cash used would have been higher except we issued more long-term debt and common stock in 1998 compared to 1997.

In 1997, cash used in financing activities increased from 1996 mostly because of the repayment of long-term debt and short-term borrowings that matured, sinking fund requirements, and early redemptions of higher cost securities. Net cash used would have been higher except we issued more long-term debt in 1997 compared to 1996.

Security Ratings

Independent credit-rating agencies rate our fixed-income securities. The ratings indicate the agencies' assessment of our ability to pay interest, distributions, dividends, and principal on these securities. These ratings affect how much it will cost us to sell these securities. The better the rating, the lower the cost of the securities to us when we sell them. Our securities ratings at the date of this report are shown in the following table.

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

Capital Resources

Our business requires a great deal of capital. Our actual capital requirements for the years 1996 through 1998, along with estimated annual amounts for the years 1999 through 2001, are shown in the table on page 30. For the year ended December 31, 1998, our ratio of earnings to fixed charges was 2.94 and our ratio of earnings to combined fixed charges and preferred and preference dividend requirements was 2.60.

Investment requirements for 1999 through 2001 include estimates of funding for existing and anticipated projects. We continuously review and modify those estimates. Actual investment requirements may vary from the estimates included in the table on page 30 because of a number of factors including:

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

Our estimates are also subject to additional factors. Please see "Forward Looking Statements" on page 35.

	1996	1997	1998	1999	2000	2001
			(In millions)			
Utility Business Capital Requirements:						
Construction expenditures (excluding AFC)						
Electric	$219	$ 238	$ 239	$ 285	$ 269	$ 290
Gas	84	89	55	74	70	69
Common	46	38	35	25	20	18
Total construction expenditures	349	365	329	384	359	377
AFC	10	8	10	11	13	19
Nuclear fuel (uranium purchases and processing charges)	47	44	50	50	50	48
Deferred conservation expenditures	31	27	16	1	—	—
Retirement of long-term debt and redemption of preference stock	184	243	222	341	253	195
Total utility business capital requirements	621	687	627	787	675	639
Diversified Business Capital Requirements:						
Investment requirements	118	156	325	423	480	500
Retirement of long-term debt	52	188	232	200	273	363
Total diversified business capital requirements	170	344	557	623	753	863
Total capital requirements	$791	$1,031	$1,184	$1,410	$1,428	$1,502

Capital Requirements of Our Utility Business

Our estimates of future electric construction expenditures do not include costs to build more generating units. Electric construction expenditures include improvements to generating plants and to our transmission and distribution facilities. They also include estimated costs for replacing the steam generators and extending the operating licenses at Calvert Cliffs. The operating licenses expire in 2014 for Unit 1 and in 2016 for Unit 2. We estimate these Calvert Cliffs costs to be:

- $34 million in 1999,
- $44 million in 2000, and
- $58 million in 2001.

We estimate that during the two-year period 2002 through 2003, we will spend an additional $151 million to complete the replacement of the steam generators and extend the operating licenses at Calvert Cliffs. We discuss the license extension process further in the "Calvert Cliffs License Extension" section on page 33.

If we do not replace the steam generators, we estimate that Calvert Cliffs could not operate for the full term of its current operating licenses. We expect the steam generator replacements to occur during the 2002 refueling outage for Unit 1 and during the 2003 refueling outage for Unit 2.

Additionally, our estimates of future electric construction expenditures include the costs of complying with Environmental Protection Agency (EPA) and State of Maryland 65% nitrogen oxides emissions (NOx) reduction regulations as follows:

- $29 million in 1999,
- $28 million in 2000,
- $33 million in 2001, and
- $14 million in 2002.

We discuss the NOx regulations further in Note 10 on page 61.

Our utility operations provided about 108% in 1998, 105% in 1997, and 96% in 1996 of the cash needed to meet our capital requirements, excluding cash needed to retire debt and redeem preference stock.

We will continue to have cash requirements for:

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

During the three years from 1999 through 2001, we expect utility operations to provide about 115% of the cash needed to meet our capital requirements, excluding cash needed to retire debt and redeem preference stock.

When we cannot meet our utility capital requirements internally, we sell debt and equity securities. We also sell securities when market conditions permit us to refinance existing debt or preference stock at a lower cost. The amount of cash we need and market conditions determine when and how much we sell.

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

At December 31, 1998, we have the authority from the Federal Energy Regulatory Commission to issue up to $700 million of short-term borrowings. In addition, we maintain $113 million in committed bank lines of credit and we have $100 million in bank revolving credit agreements to support the commercial paper program as discussed in Note 6 on page 57.

Capital Requirements of Our Diversified Businesses

Certain of our diversified businesses expect to expand their businesses which will require additional investments. These investment requirements include funding for:

- growing our power marketing and trading business,
- the development and acquisition of power projects, as well as loans to project entities,
- investments in financial limited partnerships, and
- funding for construction of cooling system projects.

The investment requirements exclude BGE's commitment to contribute up to $115 million in equity to Constellation Power Source, Inc. to fund its investment in Orion Power Holdings, Inc.

Our diversified businesses have met their capital requirements in the past through borrowing, cash from their operations, and from time to time equity contributions from BGE. Our diversified businesses plan to raise the cash needed to meet capital requirements in the future through these same methods. BGE Home Products & Services may also meet capital requirements through sales of receivables.

If we can get a reasonable value for our real estate projects, additional cash may be obtained by selling real estate projects. The ability to sell or liquidate assets will depend on market conditions, and we cannot give assurances that these sales or liquidations could be made. We discuss the real estate business and market in the "Other Diversified Businesses" section on page 28 and in the Notes to Consolidated Financial Statements beginning on page 45.

Our diversified businesses also have revolving credit agreements totaling $270 million to provide additional liquidity for short-term financial needs, including the issuance of up to $135 million of letters of credit.

In 1998, a subsidiary of Constellation Enterprises, Inc. issued $157 million of two- and three-year notes to several institutional investors in a private placement offering.

In 1997, our diversified businesses issued $289 million of three- and four-year notes.

We discuss our short-term borrowings in Note 6 on page 57 and long-term debt in Note 7 on page 57.

Market Risk

We are exposed to market risk, including changes in interest rates, certain commodity prices, equity prices, and foreign currency. To manage our market risk, we may enter into various derivative instruments including swaps, forward contracts, futures contracts, and options. Please refer to the "Forward Looking Statements" section on page 35. We discuss our market risk and the related use of derivative instruments in this section.

Interest Rate Risk

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

Principal Payments and Interest Rate Detail by Contractual Maturity Date

	1999	2000	2001	2002	2003	Thereafter	Total	Fair value at Dec. 31, 1998
					(In millions)			
Long-term debt								
Variable-rate debt	$306.5	$ 40.9	$ 75.0	$ 0.9	$ 6.6	$ 278.3	$ 708.2	$ 708.2
Average interest rate	5.59%	5.97%	5.92%	7.79%	6.89%	4.20%	5.11%	
Fixed-rate debt	$228.2	$485.1	$482.8	$154.6	$286.6	$1,329.7	$2,967.0	$3,076.6
Average interest rate	7.85%	7.16%	7.08%	7.31%	6.51%	6.72%	6.95%	
Preference Stock								
Fixed-rate preference stock	$ 7.0	$ —	$ —	$ —	$ —	$ —	$ 7.0	$ 7.2
Average interest rate	7.85%	—%	—%	—%	—%	—%	7.85%	

Commodity Price Risk

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

Gas Business

Our gas business may enter into gas futures, options, and swaps to hedge its price risk under our market based rates incentive mechanism and our off-system gas sales program. We discuss this further in Note 1 on page 46. At December 31, 1998, our exposure to commodity price risk for our gas business was not material.

Energy Services Businesses

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

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

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

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

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

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

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

Due to the relative immaturity of the competitive market for electricity and related derivatives and the seasonality of changes in market prices, the value at risk calculation may not reflect the full extent of our commodity price risk exposure. Additionally, actual changes in the value of options may differ from the value at risk calculated using a linear approximation inherent in our calculation method.

We discuss Constellation Power Source's trading business in the "Power Marketing and Trading" section on page 27 and in Note 1 on page 47.

The commodity price risk for our remaining energy services businesses was not material.

Equity Price Risk

We are exposed to price fluctuations in equity markets primarily through our financial investments business and our nuclear decommissioning trust fund. We are required by the Nuclear Regulatory Commission (NRC) to maintain a trust to fund the costs of decommissioning Calvert Cliffs. At December 31, 1998, equity price risk was not material. We discuss our nuclear decommissioning trust fund in more detail in Note 1 on page 49. We also describe our financial investments in more detail in Note 3 on page 52.

Foreign Currency Risk

We are exposed to foreign currency risk primarily through our power projects business. Our power projects business has $183.4 million invested in 15 international power generation and distribution projects as of December 31, 1998. To manage our exposure to foreign currency risk, the majority of our contracts are denominated in or indexed to the U.S. dollar. At December 31, 1998, foreign currency risk was not material. We discuss our international projects in the "Power Projects" section on page 28.

Other Matters

Calvert Cliffs License Extension

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

We began the license extension process in 1998 because the NRC may not rule on our application until 2002 or 2003. If the NRC denies our application, we must have adequate time to begin replacement power source planning. We cannot predict the timing of, or impact, if any, of the NRC's decision on our financial results. If our application is denied, it could have a material effect on our financial results.

Environmental Matters

You will find details of our environmental matters in Note 10 on page 61 and in our most recent Annual Report on Form 10-K under Item 1. Business—Environmental Matters. These details include financial information. Some of the information is about environmental costs that may be material to our financial results.

Year 2000 Readiness Disclosure

We have not experienced any significant year 2000 problems to date and we do not expect any significant problems to impair our operations as we transition to the new century. However, due to the magnitude and complexity of the year 2000 issue, even the most conscientious efforts cannot guarantee that every problem will be found and corrected prior to January 1, 2000. We are focusing on critical operating and business systems and expect to have contingency plans in place to deal with any problems, if they should occur. Please refer to "Forward Looking Statements" on page 35.

Utility Business

We established a year 2000 Program Management Office (PMO). Based on a work plan developed by the PMO, we have targeted the following six key areas:

- digital systems (devices with embedded microprocessors such as power instrumentation, controls, and meters),
- telecommunications systems,
- major suppliers,
- information technology applications (our customer, business, and human resources information systems),
- computer hardware and software infrastructure, and
- contingency plans.

Of these areas, digital systems have the most impact on our ability to provide electric and gas service. Telecommunications, major suppliers, and certain information technology applications also impact our ability to provide electric and gas service.

Year 2000 Project Phases

Our year 2000 project is divided into two phases:

- Phase I—initial assessment and detailed analysis, and
- Phase II—testing, remediation, certification, and contingency planning.

Phase I involves conducting an inventory of all systems and identifying appropriate resources. We have identified the following appropriate resources for each system or piece of equipment:

- BGE employees familiar with each system or piece of equipment,
- specialized contractors, and
- specific vendors.

Phase I also includes developing action plans to ensure that the key areas identified above are year 2000 ready. The action plans for each system or piece of equipment include:

- our budget,
- schedules for Phase I and II, and
- our remediation approach—repair, upgrade, replace or retire.

In evaluating our risks and estimating our costs, we utilized employees with expertise in each line of business to perform the activities under Phase I. We believe our employees are the most familiar with their systems or equipment and therefore will provide a reliable estimate of our risks and costs.

Phase II includes converting and testing all of our systems. Each system will be tested by those employees used in Phase I following formal guidelines developed by the PMO. Each system or piece of equipment will then be certified by a tester and the PMO, following testing guidelines developed with the help of outside consultants. We are currently evaluating whether we will have our year 2000 testing independently certified. Phase II also includes identifying our major suppliers and developing contingency plans. We have identified our major suppliers and are currently assessing their year 2000 readiness through surveys. We plan to follow-up with our major suppliers via interviews in early 1999.

Contingency Planning

Year 2000 operational contingency planning is underway. Staffing and initial planning was completed in 1998. Contingency plans are expected to be completed, including company-wide training, by September 1999. We are developing contingency plans using the contingency guidelines issued by the Nuclear Energy Institute (which are endorsed by the NRC), the contingency guidelines issued by the North American Electric Reliability Council (NERC), and guidance from consultants.

We are also addressing the impact of electric power grid problems that may occur outside of our own electric system. We have started year 2000 electric power grid impact planning through our various electric interconnection affiliations. The PJM interconnection has drafted year 2000 operational preparedness plans and restoration scenarios and will continue to develop these plans during the first half of 1999 in cooperation with NERC. The NERC has started monthly assessments of the electric utility industry to communicate the readiness of the national electric grid for year 2000. The NERC has scheduled two industry-wide tests for 1999.

Through the Electric Power Research Institute (EPRI), an industry-wide effort has been established to deal with year 2000 problems affecting digital systems and equipment used by the nation's electric power companies. Under this effort, participating utilities are working together to assess specific vendors' system problems and test plans. The assessment will be shared by the industry as a whole to facilitate year 2000 problem solving.

BGE has joined the American Gas Association (AGA) in an initiative similar to the one with EPRI to facilitate year 2000 problem solving among gas utilities. The AGA has initiated quarterly assessments of the gas utility industry to communicate the readiness of its members for the year 2000.

Current Status

The most reasonably likely worst case scenario faced by our utility business is any interruption in providing electric and gas service to our customers. We cannot predict the impact of any interruption on our results of operations, but the impact could be material. The following table shows our estimate as of the date of this report of the percentage completed for Phases I and II and our expected year 2000 readiness target dates for the six key areas:

	Phase I	Phase II	Year 2000 readiness target date
	(approximate % complete)		
Digital systems	98%	50%	June 1999
Telecommunications systems	100%	90%	March 1999
Major suppliers	95%	85%	June 1999
Information technology applications	100%	55%	June 1999
Computer hardware and software infrastructure	100%	80%	March 1999
Contingency plans	—	20%	September 1999

The completion percentages listed above are reviewed by our PMO in monthly status meetings with the personnel responsible for each project and their supervision. Monthly progress is also monitored by senior BGE management.

Costs

In the following table, we show the breakdown of our total costs between normal system replacements that will be capitalized (included in the Consolidated Balance Sheets) and the costs that will be expensed (included in our Consolidated Statements of Income) through operations and maintenance (O&M) cost. We also show the breakdown of non-incremental (previously included in our information technology budget) and incremental O&M cost:

		Actual Cost		Estimated Costs		Total
	1996	1997	1998	1999	2000	Costs
			(In millions)			
Total Cost	$0.1	$1.7	$18.9	$19.5	$2.0	$42.2
Less: Capital cost	—	—	7.3	5.7	—	13.0
O&M cost	0.1	1.7	11.6	13.8	2.0	29.2
Less: non-incremental O&M cost	0.1	1.7	4.6	7.0	1.0	14.4
Incremental O&M cost	$—	$—	$ 7.0	$ 6.8	$1.0	$14.8

The costs incurred in 1996 and 1997 were for Phase I. The costs incurred in 1998 were for Phases I and II. Costs incurred in 1999 and 2000 will be for Phases I and II.

In 1998 and 1999, we had and expect to have the equivalent of approximately 110 full-time employees assigned to our year 2000 project.

Diversified Businesses

Overview

Our diversified businesses have established year 2000 task forces to address their year 2000 issues and are completing their initial assessments. As the initial assessments are completed, the businesses have developed, and will be developing, action plans to prepare their systems for the year 2000. Outside consultants have been retained by several of our diversified businesses to help complete the initial assessment and detailed analysis phase, and to assist in the testing, remediation, and certification phase of their year 2000 projects. The action plans developed are similar to those used by our utility business, including a test certification process. All systems are expected to be certified by December 1999. Our diversified businesses are evaluating whether they will have their year 2000 testing independently certified.

In evaluating their risks and estimating their costs, our diversified businesses utilized employees with expertise in each line of business to perform initial assessments. We believe our diversified businesses' employees are the most familiar with their systems or equipment and therefore will provide a reliable estimate of our risks and costs.

The progress of our diversified businesses' year 2000 projects are reviewed by their year 2000 task forces in monthly status meetings with the personnel responsible for each project and their supervision. Monthly progress is also monitored by senior management for each business and periodic updates are provided to BGE senior management.

Contingency Planning
Each of our diversified businesses will develop contingency plans, which are expected to be completed by December 1999.

Current Status
The most reasonably likely worst case scenarios faced by our energy services businesses and our other diversified businesses are discussed below. However, if any of these scenarios actually occurred, the impact is not expected to be material to our consolidated financial results.

<u>Energy Services</u>
The most reasonably likely worst case scenarios for any one of our power projects would be:

- a shutdown of the plant's systems (most of which can be manually overridden),
- inability of the purchasing utility to take the plant's power, or
- lack of fuel.

Personnel at each plant are currently assessing their particular year 2000 issues and certain plants have started the testing, remediation, and certification phase of their year 2000 project.

For our power marketing and trading business and our energy products and services business, the most reasonably likely worst case scenario would be encountering any Internet access problems with trading partners, transmission service providers, independent operators, power exchanges, and various electronic bulletin boards. Each of these businesses have two internet service providers and are contracting with a third provider for alternate routing to critical Internet sites necessary to perform day-to-day business functions. Both are currently assessing their year 2000 issues.

For our home products and commercial building systems business, the most reasonably likely worst case scenarios would be any interruption in billing customers or renewing maintenance contracts. This business has substantially completed the assessment and detailed analysis phase and has started the testing, remediation, and certification phase of its year 2000 project.

<u>Other Diversified Businesses</u>
The most reasonably likely worst case scenarios for our financial investments business would be a breakdown in the systems of the brokers or safekeeping banks which it uses to trade, or the failure of its investment managers' computer programs that set investment strategy. This business is currently surveying and monitoring the year 2000 readiness of its banks, brokers, and investment managers.

For our real estate and senior-living facilities business, the most reasonably likely worst case scenario is a failure of the systems that support the health, safety, and welfare of residents in the senior-living facilities. Personnel at each facility are involved in assessing their particular year 2000 issues.

Costs
We estimate our total year 2000 costs for our power projects business to be approximately \$4.2 million, of which \$1.2 million is related to our year 2000 efforts for our Panamanian electric distribution company. The total estimated year 2000 costs for our remaining diversified businesses are approximately \$2.8 million.

Accounting Standards Issued and Adopted
We discuss recently issued and adopted accounting standards in Note 1 on page 49.

Forward Looking Statements

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

- general economic, business, and regulatory conditions,
- energy supply and demand,
- competition,
- federal and state regulations,
- availability, terms, and use of capital,
- nuclear and environmental issues,
- weather,
- industry restructuring and cost recovery (including the potential effect of stranded investments),
- commodity price risk, and
- year 2000 readiness.

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

Report of Management

The management of the Company is responsible for the information and representations in the Company's financial statements. The Company prepares the financial statements in accordance with generally accepted accounting principles based upon available facts and circumstances and management's best estimates and judgments of known conditions.

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

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

C.H. Poindexter David A. Brune

Christian H. Poindexter
Chairman, President and Chief Executive Officer

David A. Brune
Chief Financial Officer

Report of Independent Accountants

To the Shareholders of
Baltimore Gas and Electric Company

We have audited the accompanying consolidated balance sheets and statements of capitalization of Baltimore Gas and Electric Company and Subsidiaries as of December 31, 1998 and 1997, and the related consolidated statements of income, comprehensive income, cash flows, common shareholders' equity, and income taxes for each of the three years in the period ended December 31, 1998. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Baltimore Gas and Electric Company and Subsidiaries as of December 31, 1998 and 1997, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 1998 in conformity with generally accepted accounting principles.

PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Baltimore, Maryland
January 15, 1999

Consolidated Statements of Income

Baltimore Gas and Electric Company and Subsidiaries

Year Ended December 31,	1998	1997	1996
	(In millions, except per share amounts)		
Revenues			
Electric	$2,219.2	$2,191.7	$2,208.7
Gas	449.4	521.6	517.3
Diversified businesses	689.5	594.3	427.2
Total revenues	3,358.1	3,307.6	3,153.2
Expenses Other Than Interest and Income Taxes			
Electric fuel and purchased energy	505.7	519.7	547.4
Disallowed replacement energy costs (see Note 10)	—	—	95.4
Gas purchased for resale	208.6	292.1	284.4
Operations	554.1	518.3	526.4
Maintenance	177.5	178.5	174.1
Diversified businesses—selling, general, and administrative	550.9	444.9	311.1
Write-downs of real estate investments (see Note 3)	23.7	70.8	—
Depreciation and amortization	377.1	342.9	330.2
Taxes other than income taxes	219.4	216.8	214.7
Total expenses other than interest and income taxes	2,617.0	2,584.0	2,483.7
Income from Operations	741.1	723.6	669.5
Other Income (Expense)			
Write-off of merger costs (see Note 2)	—	(57.9)	—
Allowance for equity funds used during construction	6.3	5.3	6.5
Equity in earnings of Safe Harbor Water Power Corporation	5.0	5.0	4.6
Net other expense	(5.6)	(5.2)	(5.0)
Total other income (expense)	5.7	(52.8)	6.1
Income Before Interest and Income Taxes	746.8	670.8	675.6
Interest Expense			
Interest charges	247.9	241.2	217.6
Capitalized interest	(3.6)	(8.4)	(15.6)
Allowance for borrowed funds used during construction	(3.4)	(2.8)	(3.5)
Net interest expense	240.9	230.0	198.5
Income Before Income Taxes	505.9	440.8	477.1
Income Taxes	178.2	158.0	166.3
Net Income	327.7	282.8	310.8
Preferred and Preference Stock Dividends	21.8	28.7	38.5
Earnings Applicable to Common Stock	$ 305.9	$ 254.1	$ 272.3
Average Shares of Common Stock Outstanding	148.5	147.7	147.6
Earnings Per Common Share and Earnings Per Common Share—Assuming Dilution	$2.06	$1.72	$1.85

Consolidated Statements of Comprehensive Income

Baltimore Gas and Electric Company and Subsidiaries

Year Ended December 31,	1998	1997	1996
		(In millions)	
Net Income	$ 327.7	$ 282.8	$ 310.8
Other comprehensive gain/(loss), net of taxes	1.2	(0.8)	1.7
Comprehensive Income	$ 328.9	$ 282.0	$ 312.5

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

Consolidated Balance Sheets

Baltimore Gas and Electric Company and Subsidiaries

At December 31,	1998	1997
	(In millions)	
Assets		
Current Assets		
Cash and cash equivalents	$ 173.7	$ 162.6
Accounts receivable (net of allowance for uncollectibles of $20.3 and $24.1 respectively)	401.8	419.8
Trading securities	119.7	119.7
Fuel stocks	85.4	87.6
Materials and supplies	145.1	164.2
Prepaid taxes other than income taxes	68.8	65.2
Assets from energy trading activities	160.2	9.4
Other	21.4	27.4
Total current assets	1,176.1	1,055.9
Investments and Other Assets		
Real estate projects and investments	353.9	446.8
Power projects	656.8	451.7
Financial investments	198.0	196.5
Nuclear decommissioning trust fund	181.4	145.3
Net pension asset	108.0	113.0
Safe Harbor Water Power Corporation	34.4	34.4
Senior-living facilities	93.5	62.2
Other	115.4	98.7
Total investments and other assets	1,741.4	1,548.6
Utility Plant		
Plant in service		
Electric	6,890.3	6,725.6
Gas	921.3	846.9
Common	552.8	554.1
Total plant in service	8,364.4	8,126.6
Accumulated depreciation	(3,087.5)	(2,843.4)
Net plant in service	5,276.9	5,283.2
Construction work in progress	223.0	215.2
Nuclear fuel (net of amortization)	132.5	127.9
Plant held for future use	24.3	25.2
Net utility plant	5,656.7	5,651.5
Deferred Charges		
Regulatory assets (net)	565.7	597.3
Other	55.1	46.7
Total deferred charges	620.8	644.0
Total Assets	$9,195.0	$8,900.0

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

Consolidated Balance Sheets Baltimore Gas and Electric Company and Subsidiaries

At December 31,	1998	1997
	(In millions)	
Liabilities and Capitalization		
Current Liabilities		
Short-term borrowings	$ —	$ 316.1
Current portions of long-term debt and preference stock	541.7	271.9
Accounts payable	249.6	203.0
Customer deposits	35.5	30.1
Accrued taxes	6.5	5.5
Accrued interest	58.6	58.4
Dividends declared	66.1	66.3
Accrued vacation costs	34.7	36.2
Liabilities from energy trading activities	126.2	8.6
Other	45.3	44.3
Total current liabilities	1,164.2	1,040.4
Deferred Credits and Other Liabilities		
Deferred income taxes	1,309.1	1,294.9
Postretirement and postemployment benefits	217.0	185.5
Deferred investment tax credits	118.0	126.6
Decommissioning of federal uranium enrichment facilities	30.8	34.9
Other	56.3	58.4
Total deferred credits and other liabilities	1,731.2	1,700.3
Capitalization		
Long-term debt	3,128.1	2,988.9
Redeemable preference stock	—	90.0
Preference stock not subject to mandatory redemption	190.0	210.0
Common shareholders' equity	2,981.5	2,870.4
Total capitalization	6,299.6	6,159.3
Commitments, Guarantees, and Contingencies—See Note 10		
Total Liabilities and Capitalization	$9,195.0	$8,900.0

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

Consolidated Statements of Cash Flows Baltimore Gas and Electric Company and Subsidiaries

Year Ended December 31,	1998	1997	1996
		(In millions)	
Cash Flows From Operating Activities			
Net income	$ 327.7	$ 282.8	$ 310.8
Adjustments to reconcile to net cash provided by operating activities			
Depreciation and amortization	429.4	396.8	383.1
Deferred income taxes	17.5	7.4	26.0
Investment tax credit adjustments	(8.8)	(7.5)	(7.6)
Deferred fuel costs	(8.3)	18.3	0.5
Deferred conservation revenues	—	—	28.5
Disallowed replacement energy costs	—	—	95.4
Accrued pension and postemployment benefits	41.6	(18.0)	(13.8)
Write-off of merger costs	—	57.9	—
Write-downs of real estate investments	23.7	70.8	—
Allowance for equity funds used during construction	(6.3)	(5.3)	(6.5)
Equity in earnings of affiliates and joint ventures (net)	(54.5)	(42.5)	(48.3)
Changes in assets from energy trading activities	(150.8)	(9.4)	—
Changes in liabilities from energy trading activities	117.6	8.6	—
Changes in other current assets	39.2	(54.7)	(88.0)
Changes in other current liabilities	56.1	42.6	(4.9)
Other	(3.3)	(21.8)	26.7
Net cash provided by operating activities	820.8	726.0	701.9
Cash Flows From Investing Activities			
Utility construction expenditures (including AFC)	(339.4)	(373.2)	(360.5)
Allowance for equity funds used during construction	6.3	5.3	6.5
Nuclear fuel expenditures	(50.5)	(43.6)	(46.8)
Deferred conservation expenditures	(16.2)	(27.1)	(31.4)
Contributions to nuclear decommissioning trust fund	(17.6)	(17.6)	(25.5)
Merger costs	—	(20.9)	(28.5)
Purchases of marketable equity securities	(33.3)	(23.0)	(32.7)
Sales of marketable equity securities	32.8	46.5	39.7
Other financial investments	14.6	(0.4)	7.1
Real estate projects and investments	21.5	24.2	(55.3)
Power projects	(166.2)	(44.3)	(5.3)
Other	(77.0)	(46.7)	(34.3)
Net cash used in investing activities	(625.0)	(520.8)	(567.0)
Cash Flows From Financing Activities			
Proceeds from issuance of			
Short-term borrowings	1,962.2	2,719.0	3,970.8
Long-term debt	831.3	622.0	383.2
Common stock	51.8	—	3.7
Repayment of short-term borrowings	(2,278.3)	(2,736.1)	(3,916.9)
Reacquisition of long-term debt	(355.2)	(343.3)	(158.5)
Redemption of preference stock	(127.9)	(104.5)	(112.6)
Common stock dividends paid	(246.0)	(239.2)	(233.1)
Preferred and preference stock dividends paid	(21.0)	(29.7)	(37.0)
Other	(1.6)	2.5	8.8
Net cash used in financing activities	(184.7)	(109.3)	(91.6)
Net Increase in Cash and Cash Equivalents	11.1	95.9	43.3
Cash and Cash Equivalents at Beginning of Year	162.6	66.7	23.4
Cash and Cash Equivalents at End of Year	$ 173.7	$ 162.6	$ 66.7
Other Cash Flow Information			
Cash paid during the year for:			
Interest (net of amounts capitalized)	$ 236.7	$ 224.2	$ 193.6
Income taxes	$ 164.3	$ 171.2	$ 160.1

Noncash Investing and Financing Activities

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

See Notes to Consolidated Financial Statements.

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

Consolidated Statements of Common Shareholders' Equity

Baltimore Gas and Electric Company and Subsidiaries

Years Ended December 31, 1998, 1997, and 1996	Common Stock Shares	Common Stock Amount	Retained Earnings	Accumulated Other Comprehensive Income	Total Amount
	(Dollar amounts in millions, number of shares in thousands)				
Balance at December 31, 1995	147,527	$1,425.8	$1,381.4	$ 4.0	$2,811.2
Net income			310.8		310.8
Dividends declared					
Preferred and prefe.ence stock			(38.5)		(38.5)
Common stock ($1.59 per share)			(234.6)		(234.6)
Common stock issued	140	3.7			3.7
Other		0.4			0.4
Net unrealized gain on securities				2.6	2.6
Deferred taxes on net unrealized gain on securities				(0.9)	(0.9)
Balance at December 31, 1996	147,667	1,429.9	1,419.1	5.7	2,854.7
Net income			282.8		282.8
Dividends declared					
Preference stock			(28.7)		(28.7)
Common stock ($1.63 per share)			(240.7)		(240.7)
Other		3.1			3.1
Net unrealized loss on securities				(1.2)	(1.2)
Deferred taxes on net unrealized loss on securities				0.4	0.4
Balance at December 31, 1997	147,667	1,433.0	1,432.5	4.9	2,870.4
Net income			327.7		327.7
Dividends declared					
Preference stock			(21.8)		(21.8)
Common stock ($1.67 per share)			(248.1)		(248.1)
Common stock issued	1,579	51.8			51.8
Other		0.3			0.3
Net unrealized gain on securities				1.8	1.8
Deferred taxes on net unrealized gain on securities				(0.6)	(0.6)
Balance at December 31, 1998	149,246	$1,485.1	$1,490.3	$6.1	$2,981.5

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

Consolidated Statements of Capitalization

Baltimore Gas and Electric Company and Subsidiaries

At December 31,	1998	1997
	(In millions)	
Long-Term Debt		
First Refunding Mortgage Bonds of BGE		
Floating rate series, due April 15, 1999	$ 125.0	$ 125.0
8.40% Series, due October 15, 1999	91.1	91.1
5½% Series, due July 15, 2000	125.0	125.0
8⅜% Series, due August 15, 2001	122.3	122.3
7¼% Series, due July 1, 2002	124.5	124.5
5½% Installment Series, due July 15, 2002	9.1	9.8
6½% Series, due February 15, 2003	124.8	124.8
6⅛% Series, due July 1, 2003	124.9	124.9
5½% Series, due April 15, 2004	125.0	125.0
Remarketed floating rate series, due September 1, 2006	125.0	125.0
7½% Series, due January 15, 2007	123.5	123.5
6⅜% Series, due March 15, 2008	124.9	124.9
7½% Series, due March 1, 2023	125.0	125.0
7½% Series, due April 15, 2023	84.1	100.0
Total First Refunding Mortgage Bonds of BGE	1,554.2	1,570.8
Other long-term debt of BGE		
Medium-term notes, Series B	60.0	100.0
Medium-term notes, Series C	116.0	143.0
Medium-term notes, Series D	215.0	225.0
Medium-term notes, Series E	200.0	183.5
Medium-term notes, Series G	140.0	—
Pollution control loan, due July 1, 2011	36.0	36.0
Port facilities loan, due June 1, 2013	48.0	48.0
Adjustable rate pollution control loan, due July 1, 2014	20.0	20.0
5.55% Pollution control revenue refunding loan, due July 15, 2014	47.0	47.0
Economic development loan, due December 1, 2018	35.0	35.0
6.00% Pollution control revenue refunding loan, due April 1, 2024	75.0	75.0
Variable rate pollution control loan, due June 1, 2027	8.8	8.8
Total other long-term debt of BGE	1,000.8	921.3
Company obligated mandatorily redeemable trust preferred securities of subsidiary trust holding solely 7.16% deferrable interest subordinated debentures of the Company due June 30, 2038	250.0	—
Long-term debt of diversified businesses		
Loans under revolving credit agreements	74.0	22.0
Mortgage and construction loans		
8.69% mortgage note, due January 28, 1998	—	28.4
7.90% mortgage note, due September 12, 2000	8.3	8.6
8.00% mortgage note, due July 31, 2001	0.1	0.1
8.00% mortgage note, due October 30, 2003	1.8	1.6
7.50% mortgage note, due October 9, 2005	—	9.7
Variable rate mortgage notes and construction loans, due through 2004	149.5	93.5
7.357% mortgage note, due March 15, 2009	5.1	5.5
9.65% mortgage note, due February 1, 2028	9.6	9.7
8.00% mortgage note, due November 1, 2033	5.8	1.2
Unsecured notes	616.0	579.1
Total long-term debt of diversified businesses	870.2	759.4
Unamortized discount and premium	(12.4)	(13.7)
Current portion of long-term debt	(534.7)	(248.9)
Total long-term debt	$3,128.1	$2,988.9

See Notes to Consolidated Financial Statements.

continued on page 43

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

Consolidated Statements of Capitalization

Baltimore Gas and Electric Company and Subsidiaries

At December 31,	1998	1997
	(In millions)	
Preference Stock		
Cumulative, $100 par value, 6,500,000 shares authorized		
Redeemable preference stock		
7.50%, 1986 Series, 335,000 shares redeemed at $102.50 per share on July 17, 1998; 30,000 shares redeemed at par on October 1, 1998	$ —	$ 36.5
6.75%, 1987 Series, 30,000 shares redeemed at par on April 1, 1998; 395,000 shares redeemed at $102.25 on July 17, 1998	—	42.5
8.625%, 1990 Series, 130,000 shares redeemed at par on July 1, 1998	—	13.0
7.85%, 1991 Series, 70,000 shares outstanding and 140,000 shares redeemed at par on July 1, 1998	7.0	21.0
Current portion of redeemable preference stock	(7.0)	(23.0)
Total redeemable preference stock	—	90.0
Preference stock not subject to mandatory redemption		
7.78%, 1973 Series, 200,000 shares redeemed at $101 per share on July 17, 1998	—	20.0
7.125%, 1993 Series, 400,000 shares outstanding, not callable prior to July 1, 2003	40.0	40.0
6.97%, 1993 Series, 500,000 shares outstanding, not callable prior to October 1, 2003	50.0	50.0
6.70%, 1993 Series, 400,000 shares outstanding, not callable prior to January 1, 2004	40.0	40.0
6.99%, 1995 Series, 600,000 shares outstanding, not callable prior to October 1, 2005	60.0	60.0
Total preference stock not subject to mandatory redemption	190.0	210.0
Common Shareholders' Equity		
Common stock without par value, 175,000,000 shares authorized; 149,245,641 and 147,667,114 shares issued and outstanding at December 31, 1998 and 1997, respectively. (At December 31, 1998, 166,893 shares were reserved for the Employee Savings Plan and 2,372,531 shares were reserved for the Shareholder Investment Plan.)	1,485.1	1,433.0
Retained earnings	1,490.3	1,432.5
Accumulated other comprehensive income	6.1	4.9
Total common shareholders' equity	2,981.5	2,870.4
Total Capitalization	$6,299.6	$6,159.3

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

Consolidated Statements of Income Taxes

Baltimore Gas and Electric Company and Subsidiaries

Year Ended December 31,	1998	1997	1996
		(Dollar amounts in millions)	
Income Taxes			
Current	$169.5	$158.1	$147.9
Deferred			
Change in tax effect of temporary differences	14.2	(1.0)	22.0
Change in income taxes recoverable through future rates	3.9	8.0	4.9
Deferred taxes credited (charged) to shareholders' equity	(0.6)	0.4	(0.9)
Deferred taxes charged to expense	17.5	7.4	26.0
Investment tax credit adjustments	(8.8)	(7.5)	(7.6)
Income taxes per Consolidated Statements of Income	$178.2	$158.0	$166.3
Reconciliation of Income Taxes Computed at Statutory Federal Rate to Total Income Taxes			
Income before income taxes	$505.9	$440.8	$477.1
Statutory federal income tax rate	35%	35%	35%
Income taxes computed at statutory federal rate	177.1	154.3	167.0
Increases (decreases) in income taxes due to			
Depreciation differences not normalized on regulated activities	13.6	13.9	12.6
Allowance for equity funds used during construction	(2.2)	(1.9)	(2.3)
Amortization of deferred investment tax credits	(8.8)	(7.5)	(7.7)
Tax credits flowed through to income	(0.3)	(0.5)	(0.5)
Amortization of deferred tax rate differential on regulated activities	(2.3)	(2.3)	(1.9)
State income taxes	9.8	6.2	4.1
Other	(8.7)	(4.2)	(5.0)
Total income taxes	$178.2	$158.0	$166.3
Effective federal income tax rate	35.2%	35.8%	34.9%

At December 31,	1998	1997
	(In millions)	
Deferred Income Taxes		
Deferred tax liabilities		
Accelerated depreciation	$1,009.9	$ 953.5
Allowance for funds used during construction	204.5	206.7
Income taxes recoverable through future rates	88.4	89.8
Deferred termination and postemployment costs	32.3	41.1
Deferred fuel costs	4.5	1.5
Leveraged leases	22.6	25.2
Percentage repair allowance	36.8	38.7
Conservation expenditures	18.9	24.5
Energy trading activities	44.0	2.4
Other	182.6	187.7
Total deferred tax liabilities	1,644.5	1,571.1
Deferred tax assets		
Accrued pension and postemployment benefit costs	54.3	37.6
Deferred investment tax credits	41.3	44.3
Capitalized interest and overhead	46.6	44.5
Contributions in aid of construction	45.6	39.7
Nuclear decommissioning liability	22.8	20.8
Energy trading activities	30.9	1.4
Other	93.9	87.9
Total deferred tax assets	335.4	276.2
Deferred tax liability, net	$1,309.1	$1,294.9

See Notes to Consolidated Financial Statements.

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

Notes to Consolidated Financial Statements

Baltimore Gas and Electric Company and Subsidiaries

Note 1
Significant Accounting Policies

Nature of Our Business

Baltimore Gas and Electric Company (BGE) is the parent company and conducts our primary business—the electric and gas utility business. That business serves Baltimore City and all or part of 10 Central Maryland counties. We also conduct various diversified businesses in subsidiary companies. We describe our operating segments in Note 2 on page 50.

Consolidation Policy

We use three different accounting methods to report our investments in our subsidiaries or other companies: consolidation, the equity method, and the cost method.

Consolidation

We use consolidation when we own a majority of the voting stock of the subsidiary. This means the accounts of our subsidiaries are combined with our accounts. We eliminate intercompany balances and transactions when we consolidate these accounts. Our consolidated financial statements include the accounts of:

- BGE,
- Constellation Enterprises, Inc. and Subsidiaries,
- District Chilled Water General Partnership (ComfortLink), and
- BGE Capital Trust I (See Note 7 on page 58).

The Equity Method

We usually use the equity method to report investments, corporate joint ventures, partnerships, and affiliated companies (including power projects) where we hold a 20% to 50% voting interest. Under the equity method, we report:

- our interest in the entity as an investment in our Consolidated Balance Sheets beginning on page 38, and
- our percentage share of the earnings from the entity in our Consolidated Statements of Income on page 37.

The only time we do not use this method is if we can exercise control over the operations and policies of the company. If we have control, accounting rules require us to use consolidation.

We report our investment in Safe Harbor Water Power Corporation (Safe Harbor) under the equity method. Safe Harbor is a producer of hydroelectric power. BGE owns two-thirds of Safe Harbor's total capital stock, including one-half of the voting stock, and a two-thirds interest in its retained earnings.

The Cost Method

We usually use the cost method if we hold less than a 20% voting interest in an investment. Under the cost method, we report our investment at cost in our Consolidated Balance Sheets. The only time we do not use this method is when we can exercise significant influence over the operations and policies of the company. If we have significant influence, accounting rules require us to use the equity method.

Regulation of Utility Business

The Maryland Public Service Commission (Maryland PSC) regulates our utility business. Generally, we use the same accounting policies and practices used by nonregulated companies for financial reporting under generally accepted accounting principles. However, sometimes the Maryland PSC orders an accounting treatment different from that used by nonregulated companies to determine the rates we charge our customers. When this happens, we must defer certain utility expenses and income in our Consolidated Balance Sheets as regulatory assets and liabilities. We have recorded these regulatory assets and liabilities in our Consolidated Balance Sheets in accordance with Statement of Financial Accounting Standards (SFAS) No. 71 *Accounting for the Effects of Certain Types of Regulation.* We summarize and discuss our regulatory assets and liabilities further in Note 4 on page 53.

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

At December 31, 1998, we met the requirements of SFAS No. 71. We discuss our transition proposal for electric utility competition filed with the Maryland PSC in the "Competition and Response to Regulatory Change" section of Management's Discussion and Analysis on page 22.

Utility Revenues

We record utility revenues in our Consolidated Statements of Income when we provide service to customers.

Fuel and Purchased Energy Costs

We incur costs for:

- the fuel we use to generate electricity,
- purchases of electricity from others, and
- natural gas that we resell.

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

Fuel Used to Generate Electricity and Purchases of Electricity From Others

Under the electric fuel rate clause set by the Maryland PSC, we charge our electric customers for:

- the fuel we use to generate electricity (nuclear fuel, coal, gas, or oil), and
- the net cost of purchases and sales of electricity (primarily with other utilities).

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

Under the electric fuel rate clause, we defer (include as an asset or liability in our Consolidated Balance Sheets and exclude from our Consolidated Statements of Income) the difference between our actual costs of fuel and energy and what we collect from customers under the fuel rate in a given period. We either bill or refund our customers that difference in the future. We discuss this further in Note 4 on page 54.

We calculate the electric fuel rate using three factors:

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

We may change the fuel rate only if the calculated rate is more than 5% above or below the rate in effect. The fuel rate is affected most by the amount of electricity generated at our Calvert Cliffs Nuclear Power Plant (Calvert Cliffs) because the cost of nuclear fuel is cheaper than coal, gas, or oil.

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

- amortization of nuclear fuel (described under "Utility Plant" later in this note). We amortize nuclear fuel based on the energy produced over the life of the fuel. We pay quarterly fees to the Department of Energy for the future disposal of spent nuclear fuel, and accrue these fees based on the kilowatt-hours of electricity sold. We bill our customers for nuclear fuel as described earlier in this note, and
- amortization of deferred costs of decommissioning and decontaminating the Department of Energy's uranium enrichment facilities. We discuss these costs further in Note 4 on page 54.

Extended outages at Calvert Cliffs increase fuel costs and may result in fuel rate proceedings before the Maryland PSC. In these proceedings, the Maryland PSC would consider whether any portion of the extra fuel costs should be paid by BGE instead of passed on to customers. We discuss the financial impact of past extended outages in Note 10 on page 63.

Natural Gas

We charge our gas customers for the natural gas they purchase from us using "gas cost adjustment clauses" set by the Maryland PSC. These clauses operate similarly to the electric fuel rate clause described earlier in this note. However, effective October 1996, the Maryland PSC approved a modification of the gas cost adjustment clauses to provide a market based rates incentive mechanism. Under market based rates our actual cost of gas is compared to a market index (a measure of the market price of gas in a given period). The difference between our actual cost and the market index is shared equally between shareholders and customers.

Risk Management

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

Gas Business

We use basis swaps in the winter months (November through March) to hedge our price risk associated with natural gas purchases under our market based rates incentive mechanism. We also use fixed-to-floating and floating-to-fixed swaps to hedge our price risk associated with our off-system gas sales. The fixed portion represents a specific dollar amount that we will pay or receive and the floating portion represent a fluctuating amount based on a published index that we will receive or pay.

Our gas business internal guidelines do not permit the use of swap agreements for any other purpose than to hedge price risk.

We defer, as unrealized gains or losses, the net amount we are due (unrealized gains) or owe (unrealized losses) under the swap agreements in our Consolidated Balance Sheets.

When amounts are paid under the agreements, we report the payments as gas costs in our Consolidated Statements of Income.

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

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

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

Taxes
We summarize our income taxes in our Consolidated Statements of Income Taxes on page 44. As you read this section, it may be helpful to refer to those statements.

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

Our current income tax expense consists solely of regular tax less applicable tax credits. Our 1996 current income tax expense amount includes alternative minimum tax credits of $30 million. The alternative minimum tax can be carried forward indefinitely and used as tax credits in years when our regular tax liability exceeds the alternative minimum tax liability. We do not have any remaining alternative minimum tax credits.

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

Investment Tax Credits
We have deferred the investment tax credit associated with our regulated utility business in our Consolidated Balance Sheets. The investment tax credit is amortized evenly to income over the life of each property. We reduce income tax expense in our Consolidated Statements of Income for the investment tax credit and other tax credits associated with our diversified businesses, other than leveraged leases.

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

A portion of our total deferred income tax liability relates to our utility business, but has not been reflected in the rates we charge our customers. We refer to this portion of the liability as "Income taxes recoverable or payable through future rates." We have recorded that portion of the net liability as a regulatory asset in our Consolidated Balance Sheets. We discuss this further in Note 4 on page 54.

Franchise Taxes
We pay Maryland public service company franchise tax instead of state income tax on our utility revenue from sales in Maryland. We include the franchise tax in "Taxes other than income taxes" in our Consolidated Statements of Income.

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

Real Estate Projects and Investments
In Note 3 on page 52, we summarize the real estate projects and investments that are in our Consolidated Balance Sheets. The projects and investments consist of:

- land under development in the Baltimore-Washington corridor,
- an entertainment, dining, and retail complex in Orlando, Florida,
- a mixed-use planned-unit development,
- senior-living facilities, and
- beginning in 1998, a 41.9% equity interest in Corporate Office Properties Trust, a real estate investment trust.

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

Evaluation of Assets for Impairment

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

Financial Investments and Trading Securities

In Note 3 on page 52, we summarize the financial investments that are in our Consolidated Balance Sheets.

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

Trading Securities

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

Available-for-Sale Securities

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

In addition, our diversified businesses classify some of their investments in marketable equity securities as available-for-sale securities. We include any unrealized gains or losses on these securities in "Accumulated other comprehensive income" in our Consolidated Statements of Common Shareholders' Equity on page 41 and in the Consolidated Statements of Capitalization on page 43. We also include our diversified businesses' portion of unrealized gains or losses on securities of equity-method (described earlier in this note) investees in our Consolidated Statements of Common Shareholders' Equity.

Utility Plant, Depreciation, Amortization, and Decommissioning

Utility Plant

Utility plant is the term we use to describe our utility business property and equipment that is in use, being held for future use, or under construction. We summarize utility plant in our Consolidated Balance Sheets. We report our utility plant at its original cost, which includes:

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

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

We own an undivided interest in the Keystone and Conemaugh electric generating plants in Western Pennsylvania, as well as in the transmission line that transports the plants' output to the joint owners' service territories. Our ownership interests in these plants are 20.99% in Keystone and 10.56% in Conemaugh. These ownership interests represented a net investment of $152 million at December 31, 1998 and 1997. We report these properties in the same accounts we use for our other utility plant (described above).

Depreciation Expense

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

Amortization Expense

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

Decommissioning Costs

We must accumulate a reserve for the costs that we expect to incur in the future to decommission the radioactive portion of Calvert Cliffs. We do this based on a sinking fund methodology. The Maryland PSC authorized us to record decommissioning expense based on a facility-specific cost estimate so we can accumulate a decommissioning reserve of $521.0 million in 1993 dollars by the end of Calvert Cliffs' service life in 2016, adjusted to reflect expected inflation. We have reported the decommissioning reserve in "Accumulated depreciation" in our Consolidated Balance Sheets. The total reserve was $244.0 million at December 31, 1998 and $201.6 million at December 31, 1997.

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

Allowance for Funds Used During Construction and Capitalized Interest

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

The AFC rates are 9.04% for gas plant, 9.36% for common plant, and 9.40% for electric plant. We compound AFC annually.

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

Long-Term Debt

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

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

Cash Flows

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

Use of Accounting Estimates

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

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

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

Reclassifications

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

Accounting Standards Adopted

We adopted SFAS No. 130, *Reporting Comprehensive Income*, effective January 1, 1998. Comprehensive income includes net income plus all changes in shareholders' equity for the period, excluding shareholder transactions (some examples are stock issuances and dividend payments). Our comprehensive income includes net income plus the effect of unrealized gains or losses on available-for-sale securities. We have presented comprehensive income in the Consolidated Statements of Comprehensive Income, and accumulated other comprehensive income in the Consolidated Statements of Common Shareholders' Equity and in the Consolidated Statements of Capitalization.

We adopted SFAS No. 131, *Disclosures about Segments of an Enterprise and Related Information*, effective January 1, 1998. SFAS No. 131 establishes standards for the way that we report information about operating segments in annual financial statements and requires that we report selected information about operating segments in interim financial reports. SFAS No. 131 also establishes standards for related disclosures about products and services, geographic areas, and major customers. The adoption of this statement did not affect results of operations or financial position, but did affect the disclosure of segment information. See Note 2 on page 50.

We adopted SFAS No. 132, *Employers' Disclosures about Pensions and Other Postretirement Benefits,* effective January 1, 1998. SFAS No. 132 establishes standards for the way that we report our pension and postretirement benefits as well as requiring additional information on changes in the benefit obligations and fair values of plan assets. The adoption of this statement did not affect results of operations or financial position, but did affect the disclosure of pension and postretirement benefits information. See Note 5 on page 55.

Accounting Standards Issued

In March 1998, the American Institute of Certified Public Accountants (AICPA) issued Statement of Position (SOP) 98-1, *Accounting for the Costs of Computer Software Developed or Obtained for Internal Use.* SOP 98-1 establishes the accounting for the costs of computer software developed or obtained for internal use. We must adopt the requirements of this statement in our financial statements for the year ending December 31, 1999.

In April 1998, the AICPA issued SOP 98-5, *Reporting on the Costs of Start-up Activities.* SOP 98-5 establishes the accounting for the costs of start-up activities. We must adopt the requirements of this statement in our financial statements for the year ending December 31, 1999.

We do not expect the adoption of these statements to have a material impact on our financial results.

In June 1998, the FASB issued SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities.* SFAS No. 133 establishes the accounting and disclosure standards for derivative financial instruments and hedging activities. We must adopt the requirements of this standard beginning with our financial statements for the quarter ending March 31, 2000. We have not determined the effects of SFAS No. 133 on our financial results.

In November 1998, the EITF reached a consensus on EITF 98-10, *Accounting for Energy Trading and Risk Management Activities,* requiring that energy trading activities be accounted for on a mark-to-market basis. We must adopt the requirements of this consensus in our financial statements for the year ending December 31, 1999. We do not expect the adoption of this consensus to have a material impact on our financial results.

Note 2
Information by Operating Segment

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

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

Our remaining diversified businesses:

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

These reportable segments are strategic businesses based principally upon regulations, products, and services that require different technology and marketing strategies. The segments have the same accounting policies as those described in the summary of significant accounting policies in Note 1. We evaluate the performance of these segments based on net income. We account for intersegment revenues using market prices.

A summary of information by operating segment is shown on page 51.

	Electric Business	Gas Business	Energy Services Businesses	Other Diversified Businesses	Unallocated Corporate Items [(a)]	Eliminations	Consolidated
				(In millions)			
1998							
Unaffiliated revenues	$2,219.2	$449.4	$ 524.1	$165.4	$ —	$ —	$3,358.1
Intersegment revenues	1.6	1.7	12.0	0.5	—	(15.8)	—
Total revenues	2,220.8	451.1	536.1	165.9	—	(15.8)	3,358.1
Depreciation and amortization	313.0	45.4	9.2	9.3	0.2	—	377.1
Equity in earnings of equity-method investees [(b)]	5.0	—	—	—	—	—	5.0
Net interest expense	164.9	23.6	16.0	38.6	(1.9)	(0.3)	240.9
Income tax expense (benefit)	146.6	13.4	34.1	(15.8)	(0.1)	—	178.2
Net income (loss) [(c)]	278.7	28.8	43.4	(24.2)	(0.1)	1.1	327.7
Segment assets	6,342.8	934.6	1,235.0	811.6	(14.0)	(115.0)	9,195.0
Utility construction expenditures	279.0	60.4	—	—	—	—	339.4
1997							
Unaffiliated revenues	$2,191.7	$521.6	$ 399.4	$194.9	$ —	$ —	$3,307.6
Intersegment revenues	0.3	—	0.6	9.7	—	(10.6)	—
Total revenues	2,192.0	521.6	400.0	204.6	—	(10.6)	3,307.6
Depreciation and amortization	286.5	39.3	6.9	9.9	0.3	—	342.9
Equity in earnings of equity-method investees [(b)]	5.0	—	—	—	—	—	5.0
Net interest expense	160.7	20.3	10.1	32.5	6.4	—	230.0
Income tax expense (benefit)	135.7	13.9	23.8	(13.5)	(1.9)	—	158.0
Net income (loss) [(d)]	249.6	28.8	27.4	(21.1)	(3.6)	1.7	282.8
Segment assets	6,404.4	907.7	700.9	885.4	10.7	(9.1)	8,900.0
Utility construction expenditures	278.7	94.5	—	—	—	—	373.2
1996							
Unaffiliated revenues	$2,208.7	$517.3	$ 313.3	$113.9	$ —	$ —	$3,153.2
Intersegment revenues	0.3	—	1.0	5.8	—	(7.1)	—
Total revenues	2,209.0	517.3	314.3	119.7	—	(7.1)	3,153.2
Depreciation and amortization	279.3	37.8	3.2	9.6	0.3	—	330.2
Equity in earnings of equity-method investees [(b)]	4.6	—	—	—	—	—	4.6
Net interest expense	150.6	17.5	7.2	24.4	(1.2)	—	198.5
Income tax expense (benefit)	121.7	16.0	23.8	8.9	(4.1)	—	166.3
Net income (loss) [(e)]	230.9	33.9	30.6	16.8	(1.7)	0.3	310.8
Segment assets	6,466.5	826.8	485.5	901.4	11.0	(13.0)	8,678.2
Utility construction expenditures	262.5	98.0	—	—	—	—	360.5

(a) A holding company for our diversified businesses does not allocate the items presented in the table to our Energy Services and Other Diversified businesses.

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

(c) Our Energy Services businesses recorded $10.4 million for its share of earnings in a partnership as discussed in Note 3 and a $5.5 million write-off of an energy services investment as discussed in the "Other Energy Services" section of Management's Discussion and Analysis on page 28. In addition, our Other Diversified businesses recorded a $15.4 million write-down of a real estate project as discussed in Note 3.

(d) Our Electric business recorded a $37.5 million write-off related to the terminated merger with Potomac Electric Power Company as discussed in the "Write-Off of Merger Costs" section of Management's Discussion and Analysis on page 26. In addition, our Other Diversified businesses recorded a $46.0 million write-down of two real estate projects as discussed in Note 3.

(e) Our Electric business recorded a $62.1 million write-off of electric replacement energy costs as discussed in Note 10. In addition, our Energy Services businesses recorded $14.6 million for its share of earnings in a partnership and $16.2 million of write-offs of several power projects as discussed in Note 3.

Note 3
Investments

Real Estate Projects and Investments

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

At December 31,	1998	1997
	(In millions)	
Properties under development	$210.6	$220.8
Rental and operating properties (net of accumulated depreciation)	38.9	225.6
Equity interest in real estate investment trust	104.0	—
Other real estate ventures	0.4	0.4
Total real estate projects and investments	$353.9	$446.8

In 1998, CREG recorded a $15.4 million after-tax write-down of the investment in Church Street Station—an entertainment, dining, and retail complex in Orlando, Florida—which occurred because the fair value of the project has declined based upon recent competitive bids. CREG is attempting to sell this complex during 1999.

In 1998, CREG entered into an agreement with Corporate Office Properties Trust (COPT), a real estate investment trust based in Philadelphia.

Under the terms of the agreement, COPT assumed approximately $62 million of CREG's outstanding debt, paid CREG approximately $22.8 million in cash, and issued to CREG approximately 7.0 million common shares, representing a 41.9% equity interest in COPT, and 985,000 convertible preferred shares. Each convertible preferred share yields 5.5% per year, and is convertible after two years into 1.8748 common shares.

In exchange, COPT received 14 operating properties and two properties under development from CREG as well as certain other assets, options, and first refusal rights. These options and first refusal rights are related to approximately 91 acres of identified properties which are adjacent to operating properties being acquired by COPT. These options and first refusal rights have terms that range from 2-5 years.

By July 1999, COPT is expected to acquire one retail property from CREG for approximately $3.5 million in cash, unless that property is sold to another party prior to that time.

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

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

Power Projects

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

At December 31,	1998	1997
	(In millions)	
Domestic		
East	$ 39.8	$ 41.3
West	426.2	377.7
International		
South America	21.6	18.3
Central America	161.8	5.2
Other	7.4	9.2
Total power projects	$656.8	$451.7

Our Domestic-West power projects include investments of $310.6 million in 1998 and $261.4 million in 1997 that sell electricity in California under power purchase agreements called "Interim Standard Offer No. 4" agreements. We discuss these projects further in Note 10 on page 63.

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

In 1996, our power projects business recorded a $14.6 million after-tax gain for its share of earnings in a partnership. The partnership recognized a gain on the sale of a power purchase agreement. In addition, our power projects business had the following write-offs:

- a $7.0 million after-tax write-off of an investment in two geothermal wholesale power generating projects that sell electricity under California power purchase agreements. These projects were written off because the expected future cash flow from the projects were less than the investments in the projects,
- a $3.0 million after-tax write-off of development costs for a coal-fired power project when development efforts on the project were terminated, and
- a $6.2 million after-tax write-off of a portion of an investment in a solar power project to reflect a settlement with the project's lender.

Financial Investments

Financial investments consist of the following:

At December 31,	1998	1997
	(In millions)	
Insurance company	$102.5	$ 88.8
Marketable equity securities	25.3	33.3
Financial limited partnerships	41.9	43.6
Leveraged leases	28.3	30.8
Total financial investments	$198.0	$196.5

Investments Classified as Available-for-Sale

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

We show the fair values, gross unrealized gains and losses, and amortized cost bases for all of our available-for-sale securities, exclusive of $6.2 million in 1998 and $3.5 million in 1997 of unrealized net gains on securities of equity-method investees, in the following tables:

At December 31, 1998	Amortized Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value
		(In millions)		
Marketable Equity Securities	$ 82.9	$24.2	$(0.4)	$106.7
U.S. Government agency	12.7	0.4	—	13.1
State municipal bonds	64.8	2.7	—	67.5
Totals	$160.4	$27.3	$(0.4)	$187.3

At December 31, 1997	Amortized Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value
		(In millions)		
Marketable Equity Securities	$ 77.3	$12.0	$(0.5)	$ 88.8
U.S. Government agency	14.9	0.2	—	15.1
State municipal bonds	65.5	2.2	—	67.7
Totals	$157.7	$14.4	$(0.5)	$171.6

These tables include $23.9 million in 1998 and $10.0 million in 1997 of unrealized net gains associated with the nuclear decommissioning trust fund which are reflected as a change in the nuclear decommissioning trust fund on the Consolidated Balance Sheets.

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

	1998	1997	1996
		(In millions)	
Gross realized gains	$4.2	$ 9.3	$ 4.3
Gross realized losses	(0.7)	(0.6)	(0.2)
Net realized gains	$3.5	$ 8.7	$ 4.1

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

At December 31, 1998	Amount
	(In millions)
Less than 1 year	$ —
1-5 years	33.5
5-10 years	29.9
More than 10 years	17.2
Total maturities of debt securities	$80.6

Note 4
Regulatory Assets (net)

As discussed in Note 1 on page 45, the Maryland PSC regulates our utility business. Generally, we use the same accounting policies and practices used by nonregulated companies for financial reporting under generally accepted accounting principles. However, sometimes the Maryland PSC orders an accounting treatment different from that used by nonregulated companies to determine the rates we charge our customers. When this happens, we must defer certain utility expenses and income in our Consolidated Balance Sheets as regulatory assets and liabilities. We then record them in our Consolidated Statements of Income (using amortization) when we include them in the rates we charge our customers.

We summarize our regulatory assets and liabilities in the following table, and we discuss each of them separately on page 54.

At December 31,	1998	1997
	(In millions)	
Income taxes recoverable through future rates (net)	$252.6	$256.5
Deferred postretirement and postemployment benefit costs	90.0	96.4
Deferred nuclear expenditures	73.3	77.7
Deferred conservation expenditures	53.4	55.8
Deferred costs of decommissioning federal uranium enrichment facilities	38.5	42.4
Deferred environmental costs	33.4	38.8
Deferred fuel costs (net)	12.7	4.4
Deferred termination benefit costs	2.2	21.0
Other (net)	9.6	4.3
Total regulatory assets (net)	$565.7	$597.3

Income Taxes Recoverable Through Future Rates (net)

As described in Note 1 on page 47, income taxes recoverable through future rates are the portion of our net deferred income tax liability that is applicable to our utility business, but has not been reflected in the rates we charge our customers. These income taxes represent the tax effect of temporary differences in depreciation and the allowance for equity funds used during construction, offset by differences in deferred tax rates and deferred taxes on deferred investment tax credits. We amortize these amounts as the temporary differences reverse.

Deferred Postretirement and Postemployment Benefit Costs

Deferred postretirement and postemployment benefit costs are the costs we recorded under SFAS No. 106 (for postretirement benefits) and SFAS No. 112 (for postemployment benefits) in excess of the costs we included in the rates we charge our customers. We began amortizing these costs over a 15-year period in 1998. We discuss these costs further in Note 5 on page 55.

Deferred Nuclear Expenditures

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

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

We are amortizing these costs over the remaining life of the plant in accordance with the Maryland PSC's orders.

Deferred Conservation Expenditures

Deferred conservation expenditures include two components:

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

The Maryland PSC allows us to collect from customers money spent on conservation programs under a "conservation surcharge." However, under this surcharge the Maryland PSC limits what our profit can be. If, at the end of the year, we have exceeded our allowed profit, we defer the excess in that year and we lower the amount of future surcharges to our customers to correct the amount of overage, plus interest.

During 1996, we exceeded our profit limit under the conservation surcharge. As a result, we deferred $28.5 million of our 1996 revenue from surcharge billings as a regulatory liability. To correct the overage, we lowered the surcharge on our customers' bills over a 12-month period beginning July 1997 through June 1998.

Deferred Costs of Decommissioning Federal Uranium Enrichment Facilities

Deferred costs of decommissioning federal uranium enrichment facilities are the unamortized portion of our required contributions to a fund for decommissioning and decontaminating the Department of Energy's uranium enrichment facilities. We are required, along with other domestic utilities, by the Energy Policy Act of 1992 to make contributions to the fund. The contributions are generally payable over 15 years with escalation for inflation and are based upon the proportionate amount of uranium enriched by the Department of Energy for each utility. We are amortizing these costs over the contribution period as a cost of fuel. We also discuss this in Note 1 on page 46.

Deferred Environmental Costs

Deferred environmental costs are the estimated costs of investigating and cleaning up contaminated sites we own. We discuss this further in Note 10 on page 62. We are amortizing $21.6 million of these costs (the amount we had incurred through October 1995) over a 10-year period in accordance with the Maryland PSC's November 1995 order.

Deferred Fuel Costs

As described in Note 1 on page 46, deferred fuel costs are the difference between our actual costs of electric fuel, net purchases and sales of electricity, and natural gas and our fuel rate revenues collected from customers. We reduce deferred fuel costs as we collect them from or refund them to our customers.

We show our deferred fuel costs in the following table:

At December 31,	1998	1997
	(In millions)	
Electric over-recovered fuel costs	$(11.5)	$(19.0)
Gas deferred fuel costs	24.2	23.4
Deferred fuel costs (net)	$ 12.7	$ 4.4

Deferred Termination Benefits

Deferred termination benefit costs are the net unamortized balance of the cost of certain termination benefits offered to employees of our regulated utility operations in 1992 and 1993. We are amortizing these costs over a five-year period in accordance with the Maryland PSC's orders.

Note 5

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

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

Pension Benefits

We sponsor several defined benefit pension plans for our employees. A defined benefit plan specifies the amount of benefits a plan participant is to receive using information about the participant. Our largest plan covers nearly all BGE employees and certain employees of our subsidiaries. Our other plans, which are not material in amount, provide supplemental benefits to certain key employees. Our employees do not contribute to these plans. Generally, we calculate the benefits under these plans based on age, years of service, and pay.

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

We fund the plans by contributing at least the minimum amount required under Internal Revenue Service regulations. We calculate the amount of funding using an actuarial method called the projected unit credit cost method. The assets in all of the plans at December 31, 1998 were mostly marketable equity and fixed income securities, and group annuity contracts.

Postretirement Benefits

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

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

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

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

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

- in an April 1993 rate order, the Maryland PSC allowed us to expense one-half and defer, as a regulatory asset (see Note 4 on page 54), the other half of the increase in annual postretirement benefit costs related to our electric and gas businesses, and
- in a November 1995 rate order, the Maryland PSC allowed us to expense all of the increase in annual postretirement benefit costs related to our gas business.

Beginning in 1998, the Maryland PSC authorized us to:

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

Obligations, Assets, and Funded Status

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

	Pension Benefits		Postretirement Benefits	
	1998	1997	**1998**	1997
	(In millions)			
Change in benefit obligation				
Benefit obligation at January 1,	**$ 902.0**	$846.3	**$320.3**	$311.0
Service cost	**21.6**	16.8	**6.6**	5.4
Interest cost	**63.0**	61.3	**23.4**	21.8
Plan participants' contributions	**—**	—	**2.0**	2.0
Actuarial loss (gain)	**102.9**	35.5	**48.9**	(2.1)
Benefits paid	**(58.2)**	(57.9)	**(18.1)**	(17.8)
Benefit obligation at December 31,	**$1,031.3**	$902.0	**$383.1**	$320.3
Change in plan assets				
Fair value of plan assets at January 1,	**$912.3**	$795.4	**$ —**	$ —
Actual return on plan assets	**116.9**	130.0	**—**	—
Employer contribution	**14.5**	44.8	**16.1**	15.8
Plan participants' contributions	**—**	—	**2.0**	2.0
Benefits paid	**(58.2)**	(57.9)	**(18.1)**	(17.8)
Fair value of plan assets at December 31,	**$985.5**	$912.3	**$ —**	$ —

	Pension Benefits		Postretirement Benefits	
	1998	1997	1998	1997
	(In millions)			
Funded status				
Funded status at December 31,	$ (45.8)	$ 10.3	$(383.1)	$(320.3)
Unrecognized net actuarial loss	137.6	84.2	59.7	10.9
Unrecognized prior service cost	16.9	19.4	—	—
Unrecognized transition obligation	—	—	159.3	170.6
Unamortized net asset from adoption of SFAS No. 87	(0.7)	(0.9)	—	—
Prepaid (accrued) benefit cost	$108.0	$113.0	$(164.1)	$(138.8)

Net Periodic Benefit Cost

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

Year Ended December 31,	1998	1997	1996
		(In millions)	
Components of net periodic pension benefit cost			
Service cost	$21.6	$16.8	$16.1
Interest cost	63.0	61.3	59.9
Expected return on plan assets	(72.1)	(66.9)	(62.8)
Amortization of transition asset	(0.2)	(0.2)	(0.2)
Amortization of prior service cost	2.5	2.5	2.5
Recognized net actuarial loss	5.6	4.6	4.9
Amount capitalized as construction cost	(3.8)	(2.5)	(2.4)
Net periodic pension benefit cost	$16.6	$15.6	$18.0

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

Year Ended December 31,	1998	1997	1996
		(In millions)	
Components of net periodic postretirement benefit cost			
Service cost	$ 6.6	$ 5.4	$ 5.5
Interest cost	23.4	21.8	21.9
Amortization of transition obligation	11.4	11.4	11.4
Recognized net actuarial loss	0.2	0.1	0.2
Amount capitalized as construction cost	(8.1)	(7.6)	(6.2)
Amount deferred	—	(7.2)	(7.4)
Net periodic postretirement benefit cost	$33.5	$23.9	$25.4

Assumptions

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

	Pension Benefits		Postretirement Benefits	
At December 31,	1998	1997	1998	1997
Discount rate	6.50%	7.25%	6.50%	7.25%
Expected return on plan assets	9.00	9.00	N/A	N/A
Rate of compensation increase	4.00	4.00	4.00	4.00

We assumed the health care inflation rates to be:

- in 1998, 6.0% for both Medicare-eligible retirees and retirees not covered by Medicare, and
- in 1999, 7.5% for Medicare-eligible retirees and 9.0% for retirees not covered by Medicare.

After 1999, we assumed both inflation rates will decrease by 0.5% annually to a rate of 5.5% in the years 2003 and 2006.

A 1% increase in the health care inflation rate from the assumed rates would increase the accumulated postretirement benefit obligation by approximately $52.8 million as of December 31, 1998 and would increase the combined service and interest costs of the postretirement benefit cost by approximately $4.5 million annually.

A 1% decrease in the health care inflation rate from the assumed rates would decrease the accumulated postretirement benefit obligation by approximately $41.7 million as of December 31, 1998 and would decrease the combined service and interest costs of the postretirement benefit cost by approximately $3.5 million annually.

Other Postemployment Benefits

We provide the following postemployment benefits:

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

The liability for these benefits totaled $52.9 million as of December 31, 1998 and $45.4 million as of December 31, 1997.

Effective December 31, 1993, we adopted SFAS No. 112, *Employers' Accounting for Postemployment Benefits.* We deferred, as a regulatory asset (see Note 4 on page 54), the postemployment benefit liability attributable to our utility business as of December 31, 1993, consistent with the

Maryland PSC's orders for postretirement benefits (described earlier in this note). We began to amortize the regulatory asset over 15 years beginning in 1998. The Maryland PSC authorized us to reflect this change in our current electric and gas base rates to recover the higher costs in 1998.

We assumed the discount rate for other postemployment benefits to be 4.5% in 1998 and 6.0% in 1997.

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

- $10.1 million in 1998,
- $8.5 million in 1997, and
- $9.4 million in 1996.

Note 6
Short-Term Borrowings

Summary of Short-Term Borrowings
Our short-term borrowings may include bank loans, commercial paper notes, and bank lines of credit. Short-term borrowings mature within one year from the date of the financial statements. We pay commitment fees to banks for providing us lines of credit. When we borrow under the lines of credit, we pay market interest rates.

As of December 31, 1998, we had no short-term borrowings outstanding. As of December 31, 1997, we had $316.1 million outstanding consisting entirely of BGE commercial paper notes.

We had unused bank lines of credit supporting our commercial paper notes of $113 million at December 31, 1998 and $231 million at December 31, 1997. These amounts do not include unused revolving credit agreements of $100 million at December 31, 1998 and 1997 that are discussed in Note 7 on page 58.

Constellation Enterprises, Inc. has a $135 million unsecured revolving credit agreement that matures December 20, 1999, to provide liquidity for general corporate purposes including financing requirements of subsidiaries and to provide for the issuance of letters of credit to meet subsidiary business requirements. At December 31, 1998, letters of credit totaling $2.3 million were issued under this credit facility.

Weighted-Average Interest Rates
Our weighted-average effective interest rate for BGE's commercial paper notes was 5.65% for the year ended December 31, 1998 and 5.66% for 1997.

Note 7
Long-Term Debt

Long-term debt matures more than one year from the date of the financial statements. We summarize our long-term debt in the Consolidated Statements of Capitalization. As you read this section, it may be helpful to refer to those statements. We discuss BGE's and our diversified businesses' long-term debt separately below.

BGE's Long-Term Debt
BGE's First Refunding Mortgage Bonds
BGE's first refunding mortgage bonds are secured by a mortgage lien on nearly all of its assets, including all utility properties and franchises and its subsidiary capital stock. BGE's subsidiary capital stock pledged under the mortgage is that of Safe Harbor Water Power Corporation and Constellation Enterprises, Inc.

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

- 5½% Installment Series, due 2002
- 8.40% Series, due 1999
- 5½% Series, due 2000
- 8⅜% Series, due 2001
- 7¼% Series, due 2002
- 6½% Series, due 2003
- 6⅛% Series, due 2003
- 5½% Series, due 2004
- 7½% Series, due 2007
- 6⅝% Series, due 2008

Holders of the Remarketed Floating Rate Series Due September 1, 2006 have the option to require BGE to repurchase their bonds at face value on September 1 of each year. BGE is required to repurchase and retire at par any bonds that are not remarketed or purchased by the remarketing agent. BGE also has the option to redeem all or some of these bonds at face value each September 1.

BGE's Other Long-Term Debt
We show the weighted-average interest rates and maturity dates for BGE's fixed-rate medium-term notes outstanding at December 31, 1998 in the following table:

Series	Weighted-Average Interest Rate	Maturity Dates
B	8.10%	2000-2006
C	7.34	1999-2003
D	6.66	2001-2006
E	6.66	2006-2012
G	6.08	2008

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

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

BGE has $100 million of revolving credit agreements with several banks that are available through 2000 to 2001. At December 31, 1998, BGE had no outstanding borrowings under these agreements. These banks charge us commitment fees based on the daily average of the unborrowed amount, and we pay market interest rates on any borrowings. These agreements also support BGE's commercial paper notes, as described in Note 6 on page 57.

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

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

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

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

The Debentures are the only assets of the Trust. The Trust is wholly owned by BGE because we own all the common securities of the Trust that have general voting power.

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

Diversified Businesses' Long-Term Debt
Revolving Credit Agreements
A subsidiary of Constellation Enterprises, Inc. has a $75 million unsecured revolving credit agreement that matures December 9, 1999, to provide liquidity for general corporate purposes. Our diversified businesses pay a commitment fee based on the daily average of the unborrowed portion of the commitment. At December 31, 1998, our diversified businesses had $45.0 million outstanding under this agreement.

Constellation Energy Source has a $10 million revolving credit agreement that matures February 1, 2000. At December 31, 1998, Constellation Energy Source had no outstanding borrowings under this agreement. Constellation Energy Source pays a facility fee based on the total amount of the commitment.

ComfortLink has a $50 million unsecured revolving credit agreement that matures September 26, 2001. Under the terms of the agreement, ComfortLink has the option to obtain loans at various rates for terms up to nine months. ComfortLink pays a facility fee on the total amount of the commitment. At December 31, 1998, ComfortLink had $29 million outstanding under this agreement.

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

- 7.90%, due in 2000
- 8.00%, due in 2001
- 7.357%, due in 2009
- 9.65%, due in 2028

The 8.00% mortgage note due in 2003 requires interest payments until maturity. The variable rate mortgage notes and construction loans require periodic payment of principal and interest. The 8.00% mortgage note due in 2033, requires interest payments initially then monthly principal and interest payments.

Unsecured Notes

The unsecured notes mature on the following schedule:

	Amount
	(In millions)
7.30%, due April 22, 1999	$ 90.0
8.73%, due October 15, 1999	15.0
7.125%, due March 13, 2000	15.0
7.55%, due April 22, 2000	35.0
7.50%, due May 5, 2000	139.0
7.43%, due September 9, 2000	30.0
5.43%, due October 15, 2000	5.0
7.66%, due May 5, 2001	135.0
5.67%, due May 5, 2001	152.0
Total unsecured notes at December 31, 1998	$616.0

Maturities of Long-Term Debt

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

Year	BGE	Diversified Businesses
	(In millions)	
1999	$ 334.5	$200.2
2000	252.6	273.4
2001	195.2	362.6
2002	154.0	1.5
2003	284.3	8.9
Thereafter	1,584.4	23.6
Total long-term debt at December 31, 1998	$2,805.0	$870.2

At December 31, 1998, BGE had long-term loans totaling $255.0 million that mature after 2002 (including $110 million of medium-term notes discussed in this note under "BGE's Other Long-Term Debt") that lenders could potentially require us to repay early. Of this amount, $145.0 million could potentially be repaid in 1999, $60.0 million in 2002, and $50.0 million thereafter. We have the ability and intent to refinance such debt by issuing medium-term notes or by borrowing under our revolving credit agreements, if necessary.

Weighted-Average Interest Rates for Variable Rate Debt

Our weighted-average interest rates for variable rate debt were:

Year Ended December 31,	1998	1997
BGE		
Floating rate series mortgage bonds	**5.90%**	6.11%
Remarketed floating rate series mortgage bonds	**5.70**	5.75
Medium-term notes, Series D	**5.74**	5.78
Pollution control loan	**3.48**	3.63
Port facilities loan	**3.61**	3.71
Adjustable rate pollution control loan	**3.75**	3.90
Economic development loan	**3.59**	3.69
Variable rate pollution control loan	**3.45**	3.73
Diversified Businesses		
Loans under credit agreement	**6.02**	6.04
Mortgage and construction loans	**8.17**	8.10

Note 8
Redeemable Preference Stock

Priority

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

Redemptions in 1998 and 1999

During 1998, BGE redeemed all remaining shares of the following:

- the 7.50%, 1986 series,
- the 6.75%, 1987 series, and
- the 8.625%, 1990 series.

The redemptions were a combination of mandatory and optional sinking fund redemptions and early redemptions.

The remaining 70,000 shares of the 7.85%, 1991 series will be redeemed on July 1, 1999 under mandatory sinking fund provisions.

Note 9
Leases

There are two types of leases—operating and capital. Capital leases qualify as sales or purchases of property and are reported in the Consolidated Balance Sheets. All other leases are operating leases and are reported in the Consolidated Statements of Income. We present information about our operating leases below.

Incoming Lease Rentals
Some of our diversified businesses, as landlords, lease retail space to others. These operating leases expire over periods ranging from one to 20 years, and have options to renew. At December 31, 1998, our diversified businesses had property under operating leases with a net book value of $32.4 million. At December 31, 1998, tenants owed our diversified businesses future minimum rentals under operating leases as follows:

Year	*(In millions)*
1999	$ 3.4
2000	3.3
2001	3.1
2002	2.7
2003	2.7
Thereafter	24.3
Total future minimum lease rentals	$39.5

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

Lease expense was:

- $10.5 million in 1998,
- $9.5 million in 1997, and
- $11.6 million in 1996.

At December 31, 1998, we owed future minimum payments for long-term, noncancelable, operating leases as follows:

Year	*(In millions)*
1999	$ 6.7
2000	5.4
2001	4.1
2002	3.4
2003	2.2
Thereafter	5.5
Total future minimum lease payments	$27.3

Note 10
Commitments, Guarantees, and Contingencies

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

- $70.7 million in 1998,
- $65.6 million in 1997, and
- $64.1 million in 1996.

At December 31, 1998, we estimate our future payments for capacity and energy that we are obligated to buy under these contracts to be:

Year	*(In millions)*
1999	$ 61.9
2000	63.1
2001	33.4
2002	12.3
2003	12.3
Thereafter	128.3
Total estimated future payments for capacity and energy under long-term contracts	$311.3

Some of our diversified businesses have committed to contribute additional capital and to make additional loans to some affiliates, joint ventures, and partnerships in which they have an interest. At December 31, 1998, the total amount of investment requirements committed to by our diversified businesses was $19.9 million.

In March 1998, our power marketing and trading business, Constellation Power Source, Inc. and Goldman, Sachs Capital Partners II L.P., an affiliate of Goldman, Sachs & Co., formed Orion Power Holdings, Inc. (Orion) to acquire electric generating plants in the United States and Canada. Constellation Power Source owns a minority interest in Orion, and BGE has committed to contribute up to $115 million in equity to Constellation Power Source to fund its investment in Orion.

BGE and BGE Home Products & Services have agreements to sell on an ongoing basis an undivided interest in a designated pool of customer receivables. Under the agreements, BGE can sell up to a total of $40 million, and BGE Home Products & Services can sell up to a total of $50 million. Under the terms of the agreements, the buyer of the receivables has limited recourse against BGE and has no recourse against BGE Home Products & Services. BGE and BGE Home Products & Services have recorded a reserve for credit losses. At December 31, 1998, BGE had sold $33.6 million and BGE Home Products & Services had sold $45.3 million of receivables under these agreements.

Guarantees

BGE guarantees two-thirds of certain debt of Safe Harbor Water Power Corporation. The maximum amount of our guarantee is $23 million. At December 31, 1998, Safe Harbor Water Power Corporation had outstanding debt of $23.6 million, of which $15.7 million is guaranteed by BGE.

BGE has issued guarantees in an amount up to $162 million related to credit facilities and contractual performance of certain of its diversified subsidiaries. At December 31, 1998, letters of credit totaling $2.3 million were issued under one of the credit facilities.

At December 31, 1998, our diversified businesses had guaranteed outstanding loans and letters of credit of certain power projects and real estate projects totaling $59.7 million. Our diversified businesses also guarantee certain other borrowings of various power projects and real estate projects.

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

Environmental Matters

Clean Air

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

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

- Phase I became effective January 1, 1995. We met the requirements of this phase by installing flue gas desulfurization systems (scrubbers), switching fuels, and retiring some units.
- Phase II must be implemented by January 1, 2000. We are currently examining what actions we should take to comply with this phase. We expect to meet the compliance requirements through some combination of installing flue gas desulfurization systems (scrubbers), switching fuels, retiring some units, or allowance trading.

Title I addresses emissions of NOx. The Maryland Department of the Environment (MDE) issued NOx regulations which took effect June 1, 1998. The MDE regulations require major NOx sources to reduce NOx emissions up to 65% by May, 1999. While we are already taking steps to control NOx emissions at our generating plants, we communicated to MDE that we could not install the required technology at our Brandon Shores plant in time to meet the MDE's May, 1999 deadline. On June 19, 1998, we filed a lawsuit against MDE in Baltimore challenging these regulations. On February 9, 1999, the Baltimore City Circuit Court ordered the MDE to reissue the regulations with a new compliance date, indicating it was impossible for utilities to meet the May, 1999 deadline. We do not anticipate that MDE will appeal the court's decision.

The EPA issued a final rule in September, 1998 that requires the reduction of NOx emissions up to 85% by 22 states (including Maryland and Pennsylvania). The 22 states must submit plans to the EPA by September 1999 showing how they will meet its new requirements.

Based on the MDE and EPA regulations, we currently estimate that the additional controls needed at our generating plants to meet the 65% NOx emission reduction requirements will cost approximately $126 million. Through December 31, 1998, we have spent approximately $21.5 million to meet the 65% reduction requirements. We can not estimate the cost for the 85% reduction requirements at this time; however, these costs could be material.

In July 1997, the EPA published National Ambient Air Quality Standards for very fine particulates and revised standards for ozone attainment. These standards may require increased controls at our fossil generating plants in the future. We cannot estimate the cost of these increased controls at this time because the states, including Maryland, still need to determine what reductions, if any, in pollutants will be necessary to meet the federal standards.

Waste Disposal

The EPA and several state agencies have notified us that we are considered a potentially responsible party with respect to the cleanup of certain environmentally contaminated sites owned and operated by others. We cannot estimate the cleanup costs for all of these sites. We can, however, estimate that our current 15.42% share of the reasonably possible cleanup costs at one of these sites, Metal Bank of America (a metal reclaimer in Philadelphia), could be as much as $4.9 million higher than amounts we have recorded as a liability on our Consolidated Balance Sheets. This estimate is based on a Record of Decision issued by the EPA. The cleanup costs for some of the remaining sites could be significant, but we do not expect them to have a material effect on our financial position or results of operations.

Also, we are coordinating investigation of several sites where gas was manufactured in the past. The investigation of these sites includes reviewing possible actions to remove coal tar. In late December 1996, we signed a consent order with the MDE that requires us to implement remedial action plans for contamination at and around the Spring Gardens site, located in Baltimore, Maryland. We submitted the required remedial action plans and they have been approved by the MDE. Based on the remedial action plans, the costs we consider to be probable to remedy the contamination are estimated to total $47 million in nominal dollars (including inflation). We have recorded these costs as a liability on our Consolidated Balance Sheets and have deferred these costs, net of accumulated amortization and amounts we recovered from insurance companies, as a regulatory asset. We discuss this further in Note 4 on page 54. Through December 31, 1998, we have spent approximately $32 million for remediation at this site.

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

Nuclear Insurance

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

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

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

Insurance for Calvert Cliffs and Third Party Claims

For physical damage to Calvert Cliffs, we have $2.75 billion of property insurance from an industry mutual insurance company. If an outage at either of the two units at Calvert Cliffs is caused by an insured physical damage loss and lasts more than 17 weeks, we have insurance coverage for replacement power costs up to $494.2 million per unit, provided by an industry mutual insurance company. This amount can be reduced by up to $98.8 million per unit if an outage at both units of the plant is caused by a single insured physical damage loss. If accidents at any insured plants cause a shortfall of funds at the industry mutual insurance company, all policyholders could be assessed, with our share being up to $23.2 million.

In addition we, as well as others, could be charged for a portion of any third party claims associated with a nuclear incident at any commercial nuclear power plant in the country. At the date of this report, the limit for third party claims from a nuclear incident is $9.71 billion under the provisions of the Price Anderson Act. If third party claims exceed $200 million (the amount of primary insurance), our share of the total liability for third party claims could be up to $176.2 million per incident. That amount would be payable at a rate of $20 million per year.

Insurance for Worker Radiation Claims

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

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

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

Recoverability of Electric Fuel Costs

By law, we are allowed to recover our cost of electric fuel as long as the Maryland PSC finds that, among other things, we have kept the productive capacity of our generating plants at a reasonable level. To do this, the Maryland PSC will perform an evaluation of each outage (other than regular maintenance outages) at our generating plants. The evaluation will determine if we used all reasonable and cost-effective maintenance and operating control procedures to try to prevent the outage.

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

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

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

During 1989 through 1991 we had extended outages at Calvert Cliffs. These outages drove up fuel costs, and resulted in fuel rate proceedings before the Maryland PSC for several years. In these proceedings, the Maryland PSC considered whether any portion of the extra fuel costs should be charged to BGE instead of passed on to customers.

In December 1996, we settled the proceedings by agreeing not to bill our customers for $118 million of electric replacement energy costs associated with these outages. All costs associated with the outages in excess of $118 million have already been collected from customers through the fuel rate. In 1990, we wrote off $35 million of these costs. In 1996, we wrote off the remaining $83 million plus $5.6 million of related financing charges. The 1996 write-offs, together, reduced after-tax earnings by $57.6 million.

Also in 1996, we wrote off $6.8 million of fuel costs related to earlier outages that were disallowed by the Maryland PSC. This write-off reduced 1996 after-tax earnings by $4.5 million.

We have reported all of the 1996 write-offs as "Disallowed replacement energy costs" in our Consolidated Statements of Income.

California Power Purchase Agreements

Constellation Power, Inc. and subsidiaries and Constellation Investments, Inc. (whose power projects are managed by Constellation Power) have $310.6 million invested in 15 projects that sell electricity in California under power purchase agreements called "Interim Standard Offer No. 4" agreements. In 1998, earnings from these projects were $41.3 million, or $.28 per share.

Under these agreements, the projects supply electricity to utility companies at:

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

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

We use the term transition period to describe the time frame when the 10-year periods for fixed energy rates expire for these 15 power generation projects and they begin supplying electricity at variable rates. The transition period for some of the projects began in 1996 and will continue for the remaining projects through 2000. At the date of this report, eight projects had already transitioned to variable rates and seven other projects will transition in 1999 and 2000.

The projects that have already transitioned to variable rates have had lower revenues under variable rates than they did under fixed rates. However, we have not yet experienced total lower earnings from the California projects because the combined revenues from the remaining projects, which continue to supply electricity at fixed rates, are high enough to offset the lower revenues from the variable-rate projects. When the remaining projects transition to variable rates, we expect the revenues from those projects also to be lower than they are under fixed rates.

Our power projects business is pursuing alternatives for some of these power generation projects including:

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

The California projects that make the highest revenues will transition to variable rates in 1999 and 2000. The projects which transition in 1999 contributed $10.7 million, or $.07 per share to 1998 earnings, while those changing over in 2000 contributed $24.0 million, or $.16 per share to 1998 earnings. We expect earnings to ultimately decrease by similar amounts beginning in 1999 as these projects transition.

Constellation Real Estate

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

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

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

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

Management's current real estate strategy is to hold each real estate project until we can realize a reasonable value for it, except for Church Street Station which we intend to sell as discussed in Note 3. Management evaluates strategies for all its businesses, including real estate, on an ongoing basis. We anticipate that competing demands for our financial resources and changes in the utility industry will cause us to evaluate thoroughly all diversified business strategies on a regular basis so we use capital and other resources in a manner that is most beneficial.

It may be helpful for you to understand when we are required, by accounting rules, to write down the value of a real estate project to market value. A write-down is required in either of two cases. The first is if we change our intent about a project from an intent to hold to an intent to sell and the market value of that project is below book value. The second is if the expected future cash flow from the project is less than the investment in the project. We discuss our real estate projects and investments further in Note 3 on page 52.

Year 2000 Project

We have not experienced any significant year 2000 problems to date and we do not expect any significant problems to impair our operations as we transition to the new century. However, due to the magnitude and complexity of the year 2000 issue, even the most conscientious efforts cannot guarantee that every problem will be found and corrected prior to January 1, 2000. We discuss our year 2000 project further in the "Year 2000 Readiness Disclosure" section of Management's Discussion and Analysis on page 33.

Note 11
Fair Value of Financial Instruments

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

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

We show the carrying amounts and fair values of financial instruments included in our Consolidated Balance Sheets in the following table.

At December 31,	1998		1997	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In millions)			
Investments and other assets for which it is:				
Practicable to estimate fair value	$ 213.0	$ 213.0	$ 197.4	$ 198.8
Not practicable to estimate fair value	56.5	N/A	57.5	N/A
Fixed-rate long-term debt	2,954.7	3,076.6	2,637.5	2,718.4
Redeemable preference stock	7.0	7.2	113.0	116.5

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

- several financial partnerships that invest in nonpublic debt and equity securities,
- several partnerships that own solar powered energy production facilities, and
- a company involved in developing international power projects with a carrying amount of $3.7 million at December 31, 1998 and $3.0 million at December 31, 1997.

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

The investments in financial partnerships totaled $41.9 million at December 31, 1998 and $43.6 million at December 31, 1997, representing ownership interests up to 10%. The total assets of all of these partnerships totaled $5.8 billion at December 31, 1997 (which is the latest information available).

The investments in solar powered energy production facility partnerships totaled $10.9 million at December 31, 1998 and 1997, representing ownership interests up to 13%. The total assets of all of these partnerships totaled $41.5 million at December 31, 1997 (which is the latest information available).

Guarantees

It was not practicable to determine the fair value of certain loan guarantees of BGE and its diversified businesses. BGE guaranteed outstanding debt and other obligations totaling $18.0 million at December 31, 1998 and $20 million at December 31, 1997. Our diversified businesses guaranteed outstanding debt totaling $59.7 million at December 31, 1998 and $43 million at December 31, 1997. We do not anticipate that we will need to fund these guarantees.

Note 12
Quarterly Financial Data (Unaudited)

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

1998 Quarterly Data

	Revenues	Income From Operations	Net Income	Earnings Applicable to Common Stock	Earnings Per Share of Common Stock
	(In millions, except per share amounts)				
Quarter Ended:					
March 31	$ 866.1	$183.4	$ 80.2	$ 74.4	$0.50
June 30	767.6	156.2	63.2	57.4	0.39
September 30	934.0	320.4	167.7	160.9	1.08
December 31	790.4	81.1	16.6	13.2	0.09
Year Ended:					
December 31	$3,358.1	$741.1	$327.7	$305.9	$2.06

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

Our fourth quarter results include:

- a $15.4 million after-tax write-off of a real estate investment (see Note 3), and
- a $5.5 million after-tax write-off of an energy services investment. (See the "Other Energy Services" section of Management's Discussion and Analysis on page 28).

1997 Quarterly Data

	Revenues	Income From Operations	Net Income	Earnings Applicable to Common Stock	Earnings Per Share of Common Stock
	(In millions, except per share amounts)				
Quarter Ended:					
March 31	$ 887.7	$163.9	$ 72.1	$ 64.2	$0.43
June 30	746.4	78.8	15.0	7.1	0.05
September 30	860.8	321.0	171.4	164.4	1.11
December 31	812.7	159.9	24.3	18.4	0.12
Year Ended:					
December 31	$3,307.6	$723.6	$282.8	$254.1	$1.72

Our first quarter results include a $12.0 million after-tax write-down of a real estate project (see Note 3).

Our second quarter results include a $31.9 million after-tax write-down of a real estate project (see Note 3).

Our fourth quarter results include:

- a $37.5 million after-tax write-off of merger costs (see Note 2), and
- a $2.1 million after-tax write-down of a real estate project (see Note 3).

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

BGE Board of Directors
Baltimore Gas and Electric Company and Subsidiaries

CHRISTIAN H. POINDEXTER
Chairman, President and Chief Executive Officer, BGE
Age 60; elected 1988

H. FURLONG BALDWIN
Chairman and Chief Executive Officer, Mercantile Bankshares Corporation
Age 67; elected 1988

DOUGLAS L. BECKER
President and Co-Chief Executive Officer, Sylvan Learning Systems, Inc.
Age 33; elected 1998

BEVERLY B. BYRON
Former Congresswoman, U.S. House of Representatives
Age 66; elected 1993

J. OWEN COLE
Director, First Maryland Bancorp; Chairman, First National Bank of Maryland Trust Committee
Age 69; elected 1977

DAN A. COLUSSY
Former Chairman, President and Chief Executive Officer, UNC Incorporated
Age 67; elected 1992

EDWARD A. CROOKE
Vice Chairman, BGE; Chairman, President and Chief Executive Officer, Constellation Enterprises, Inc.
Age 60; elected 1988

JAMES R. CURTISS, ESQ.
Partner, Winston & Strawn
Age 45; elected 1994

JEROME W. GECKLE
Retired Chairman, PHH Corporation
Age 69; elected 1980

DR. FREEMAN A. HRABOWSKI, III
President, University of Maryland Baltimore County
Age 48; elected 1994

NANCY LAMPTON
Chairman and Chief Executive Officer, American Life and Accident Insurance Company of Kentucky
Age 56; elected 1994

CHARLES R. LARSON
Admiral, United States Navy (Retired)
Age 62; elected 1998

GEORGE V. MCGOWAN
Former Chairman and Chief Executive Officer, BGE
Age 71; elected 1988

GEORGE L. RUSSELL, JR., ESQ.
Partner, Piper & Marbury
Age 69; elected 1988

MICHAEL D. SULLIVAN
Chairman, Golf America
Age 59; elected 1992

COMMITTEES OF THE BOARD

AUDIT COMMITTEE
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Douglas L. Becker
Beverly B. Byron
Dr. Freeman A. Hrabowski, III
George L. Russell, Jr.

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J. Owen Cole
Dan A. Colussy
Michael D. Sullivan

COMMITTEE ON NUCLEAR POWER
James R. Curtiss, *Chairman*
Beverly B. Byron
Charles R. Larson
George V. McGowan

EXECUTIVE COMMITTEE
George V. McGowan, *Chairman*
H. Furlong Baldwin
Edward A. Crooke
Dr. Freeman A. Hrabowski, III
Christian H. Poindexter
George L. Russell, Jr.

LONG-RANGE STRATEGY COMMITTEE
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Douglas L. Becker
Dan A. Colussy
James R. Curtiss
Jerome W. Geckle
Nancy Lampton
Charles R. Larson
Michael D. Sullivan

COMMITTEE ON WORKPLACE DIVERSITY
Beverly B. Byron, *Chairwoman*
James R. Curtiss
Dr. Freeman A. Hrabowski, III
Nancy Lampton

Constellation Enterprises Board of Directors

EDWARD A. CROOKE
Chairman, President and Chief Executive Officer, Constellation Enterprises, Inc.; Vice Chairman, BGE
Age 60

H. FURLONG BALDWIN
Chairman and Chief Executive Officer, Mercantile Bankshares Corporation
Age 67

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Former Secretary, Maryland Department of Business and Economic Development
Age 58

ROGER W. GALE
President, Washington International Energy Group
Age 52

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Retired Chairman, PHH Corporation
Age 69

EDWARD W. KAY*
Retired Co-Chairman and Chief Operating Officer, Ernst & Young
Age 71

GEORGE V. MCGOWAN
Former Chairman and Chief Executive Officer, BGE
Age 71

CHRISTIAN H. POINDEXTER
Chairman, President and Chief Executive Officer, BGE
Age 60

MAYO A. SHATTUCK, III
Co-Chairman and Co-Chief Executive Officer, BT Alex. Brown, Incorporated
Age 44

CHARLES W. SHIVERY
Chairman, President and Chief Executive Officer Constellation Power Source, Inc.
Age 53

* *Mr. Kay retired from the Board on December 31, 1998.*

Executive Officers

BALTIMORE GAS AND ELECTRIC COMPANY

CHRISTIAN H. POINDEXTER
Chairman, President and Chief Executive Officer
Age 60

EDWARD A. CROOKE
Vice Chairman
Age 60

ROBERT E. DENTON
Executive Vice President, Generation
Age 55

FRANK O. HEINTZ
Executive Vice President, Utility Operations
Age 54

THOMAS F. BRADY
Vice President, Corporate Strategy & Development
Age 49

DAVID A. BRUNE
Vice President, Finance & Accounting, Chief Financial Officer and Secretary
Age 58

CHARLES H. CRUSE
Vice President, Nuclear Energy
Age 54

CARSERLO DOYLE
Vice President, Gas Distribution
Age 56

E. FRANK BENDER, JR.
Vice President, Retail Services
Age 51

ROBERT S. FLEISHMAN
Vice President, Corporate Affairs and General Counsel
Age 45

RONALD W. LOWMAN
Vice President, Fossil Energy
Age 54

GREGORY C. MARTIN
Vice President, General Services and Chief Information Officer
Age 50

LINDA D. MILLER
Vice President, Human Resources
Age 48

STEPHEN F. WOOD
Vice President, Electric Transmission & Distribution
Age 46

RICHARD M. BANGE, JR.
Controller, Accounting
Age 54

THOMAS E. RUSZIN, JR.
Treasurer, Finance
Age 44

CONSTELLATION ENTERPRISES

EDWARD A. CROOKE
Chairman, President and Chief Executive Officer
Age 60

DIANE L. FEATHERSTONE
President, Constellation Energy Source, Inc.
Age 45

STEVEN D. KESLER
President, Constellation Investments, Inc.
Age 47

WILLIAM H. MUNN
President and Chief Executive Officer, BGE Home Products & Services, Inc.
Age 51

CHARLES W. SHIVERY
Chairman, President and Chief Executive Officer Constellation Power Source, Inc.
Age 53

JOHN F. WALTER
President, Constellation Power, Inc.
Age 64

RONALD F. WATSON
President, Constellation Senior Services, Inc.
Age 50

Five-Year Statistical Summary

Baltimore Gas and Electric Company and Subsidiaries

	1998	1997	1996	1995	1994
Common Stock Data					
Quarterly Earnings Per Share					
First Quarter	$0.50	$0.43	$0.62	$0.41	$0.49
Second Quarter	0.39	0.05	0.36	0.28	0.39
Third Quarter	1.08	1.11	0.93	1.04	0.79
Fourth Quarter	0.09	0.12	(0.06)	0.29	0.26
Total	$2.06	$1.72	$1.85	$2.02	$1.93
Dividends					
Dividends Declared Per Share	$1.67	$1.63	$1.59	$1.55	$1.51
Dividends Paid Per Share	1.66	1.62	1.58	1.54	1.50
Dividend Payout Ratio					
Reported	81.1%	94.8%	85.9%	76.7%	78.2%
Excluding nonrecurring charges to earnings	75.9%	71.5%	70.0%	76.7%	78.2%
Market Prices					
High	$ $35\frac{1}{4}$	$ $34\frac{5}{16}$	$ $29\frac{1}{2}$	$ 29	$ $25\frac{1}{2}$
Low	$29\frac{1}{4}$	$24\frac{3}{4}$	25	22	$20\frac{1}{2}$
Close	$30\frac{7}{8}$	$34\frac{1}{8}$	$26\frac{3}{4}$	$28\frac{1}{2}$	$22\frac{1}{8}$
Capital Structure					
Consolidated					
Long-Term Debt	53.5%	48.0%	45.0%	42.8%	46.1%
Short-Term Debt	—	4.7	5.1	4.4	1.0
Preferred and Preference Stock	2.9	4.8	6.5	8.5	8.9
Common Shareholders' Equity	43.6	42.5	43.4	44.3	44.0
Utility Only					
Long-Term Debt	51.5%	45.4%	42.5%	40.4%	43.5%
Short-Term Debt	—	5.8	6.1	5.2	1.2
Preferred and Preference Stock	3.6	5.9	7.8	10.0	10.6
Common Shareholders' Equity	44.9	42.9	43.6	44.4	44.7

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

The quarterly earnings per share amounts include certain one-time adjustments as shown in Note 12 to the Consolidated Financial Statements.

Shareholder Information

Baltimore Gas and Electric Company and Subsidiaries

Common Stock Dividends and Price Ranges

	1998				1997		
	Dividend Declared	Price High	Price Low		Dividend Declared	Price High	Price Low
First Quarter	$ .41	$34 1/8	$29 3/4	First Quarter	$ .40	$28	$26 1/4
Second Quarter	.42	32 15/16	29 1/4	Second Quarter	.41	27	24 3/4
Third Quarter	.42	33 5/8	29 5/16	Third Quarter	.41	28 1/16	26
Fourth Quarter	.42	35 1/4	30 1/8	Fourth Quarter	.41	34 5/16	25 13/16
Total	$1.67			Total	$1.63		

Dividend Policy

The common stock is entitled to dividends when and as declared by the Board of Directors. There are no limitations in any indenture or other agreements on payment of dividends unless we elect to defer interest payments on the 7.16% Deferrable Interest Subordinated Debentures due June 30, 2038, and any deferred interest remains unpaid; or all dividends (and any redemption payments) due on our preference stock have not been paid.

Dividends have been paid on the common stock continuously since 1910. Future dividends depend upon future earnings, the financial condition of the company, and other factors.

Common Stock Dividend Dates

Record dates are normally on the 10th of March, June, September, and December. Quarterly dividends are customarily mailed to each shareholder on or about the 1st of April, July, October, and January.

Stock Trading

BGE's common stock, which is traded under the ticker symbol BGE, is listed on the New York, Chicago, and Pacific stock exchanges, and has unlisted trading privileges on the Boston, Cincinnati, and Philadelphia exchanges. As of December 31, 1998 there were 69,888 common shareholders of record.

Annual Meeting

The annual meeting of shareholders will be held at 10 a.m. on Friday, April 16, 1999 at the Morris Mechanic Theatre, 25 Hopkins Plaza, Baltimore, Maryland 21201.

Form 10-K

Upon written request, the company will furnish, without charge, a copy of its Annual Report on Form 10-K, including financial statements, after it is filed with the Securities and Exchange Commission in March 1999. Requests should be addressed to David A. Brune, Chief Financial Officer and Secretary, Vice President, Finance & Accounting, P.O. Box 1475, Baltimore, Maryland 21203-1475.

Auditors

PricewaterhouseCoopers LLP

Executive Offices

Gas and Electric Building
Charles Center
Baltimore, Maryland 21201
Mail: P.O. Box 1475
Baltimore, Maryland 21203-1475

Shareholder Investment Plan

BGE's Shareholder Investment Plan provides common shareholders an easy and economical way to acquire additional shares of common stock. The plan allows shareholders to: reinvest all or part of their common stock dividends, purchase additional shares of common stock, deposit the common stock they hold into the plan, and request a transfer or sale of shares held in their accounts.

Stock Transfer Agents and Registrars

Transfer Agent and Registrar:
Baltimore Gas and Electric Company,
Baltimore, Maryland

Co-Transfer Agent and Registrar:
Harris Trust and Savings Bank,
Chicago, Illinois

Shareholder Assistance and Inquiries

If you need assistance with lost or stolen stock certificates or dividend checks, name changes, address changes, stock transfers, the Shareholder Investment Plan, or other matters, you may contact our shareholder service representatives as follows:

By telephone (Monday-Friday, 8 a.m.-4:45 p.m.):

Baltimore Metropolitan Area	410-783-5920
Within Maryland	1-800-492-2861
Outside Maryland	1-800-258-0499

By U.S. mail:
Baltimore Gas and Electric Company
Shareholder Services,
P.O. Box 1642
Baltimore, MD 21203-1642

In person or by overnight delivery:
Baltimore Gas and Electric Company
Shareholder Services-Room 820
39 W. Lexington Street
Baltimore, MD 21201

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Baltimore, Maryland 21203

www.bge.com

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Baltimore Gas and Electric Company and Subsidiaries

Common Stock Dividends and Price Ranges

	1998			1997		
	Dividend Declared	Price High	Price Low	Dividend Declared	Price High	Price Low
First Quarter	$ .41	$ $34\frac{1}{8}$	$ $29\frac{3}{4}$	$ .40	$ 28	$ $26\frac{1}{4}$
Second Quarter	.42	$32\frac{15}{16}$	$29\frac{1}{4}$	.41	27	$24\frac{3}{4}$
Third Quarter	.42	$33\frac{5}{8}$	$29\frac{5}{16}$	.41	$28\frac{1}{16}$	26
Fourth Quarter	.42	$35\frac{1}{4}$	$30\frac{1}{8}$	.41	$34\frac{5}{16}$	$25\frac{13}{16}$
Total	$1.67			$1.63		

Dividend Policy

The common stock is entitled to dividends when and as declared by the Board of Directors. There are no limitations in any indenture or other agreements on payment of dividends unless we elect to defer interest payments on the 7.16% Deferrable Interest Subordinated Debentures due June 30, 2038, and any deferred interest remains unpaid; or all dividends (and any redemption payments) due on our preference stock have not been paid.

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Executive Offices

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Mail: P.O. Box 1475
Baltimore, Maryland 21203-1475

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Baltimore, Maryland

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Harris Trust and Savings Bank,
Chicago, Illinois

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Outside Maryland	1-800-258-0499

By U.S. mail:
Baltimore Gas and Electric Company
Shareholder Services,
P.O. Box 1642
Baltimore, MD 21203-1642

In person or by overnight delivery:
Baltimore Gas and Electric Company
Shareholder Services-Room 820
39 W. Lexington Street
Baltimore, MD 21201

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BGE

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