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

Form 10-Q

(Mark One)

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

For the quarterly period ended March 31, 2003

OR

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

For the transition period from to

Commission File Number 1-14365

El Paso Corporation

(Exact Name of Registrant as Specified in its Charter)

Delaware (State or Other Jurisdiction of Incorporation or Organization)	**76-0568816** (I.R.S. Employer Identification No.)
El Paso Building **1001 Louisiana Street** **Houston, Texas** (Address of Principal Executive Offices)	**77002** (Zip Code)

Telephone Number: **(713) 420-2600**
Internet Website: www.elpaso.com

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

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act). Yes ☑ No ☐

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

Common stock, par value $3 per share. Shares outstanding on May 12, 2003: 599,108,034

EL PASO CORPORATION

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Below is a list of terms that are common to our industry and used throughout this document:

/d	= per day	MBbls	= thousand barrels
Bbl	= barrels	MMBtu	= million British thermal units
BBtu	= billion British thermal units	Mcf	= thousand cubic feet
Bcf	= billion cubic feet	MMcf	= million cubic feet

When we refer to natural gas and oil in "equivalents," we are doing so to compare quantities of oil with quantities of natural gas or to express these different commodities in a common unit. In calculating equivalents, we use a generally recognized standard in which one Bbl of oil is equal to six Mcf of natural gas. Also, when we refer to cubic feet measurements, all measurements are at a pressure of 14.73 pounds per square inch.

When we refer to "us", "we", "our", "ours", or "El Paso", we are describing El Paso Corporation and/or our subsidiaries.

PART I — FINANCIAL INFORMATION

Item 1. Financial Statements

EL PASO CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(In millions, except per common share amounts)
(Unaudited)

	Quarter Ended March 31, 2003	Quarter Ended March 31, 2002
Operating revenues	$4,018	$3,765
Operating expenses		
Cost of products and services	2,508	1,623
Operation and maintenance	687	662
Depreciation, depletion and amortization	361	365
Ceiling test charges	—	33
(Gain) loss on long-lived assets	318	(15)
Taxes, other than income taxes	83	85
	3,957	2,753
Operating income	61	1,012
Losses from unconsolidated affiliates	(99)	(223)
Minority interest in consolidated subsidiaries	1	(52)
Other income	39	42
Other expenses	(126)	(66)
Interest and debt expense	(345)	(307)
Return on preferred interests of consolidated subsidiaries	(39)	(40)
Income (loss) before income taxes	(508)	366
Income taxes	(133)	118
Income (loss) from continuing operations	(375)	248
Discontinued operations, net of income taxes	3	(19)
Cumulative effect of accounting changes, net of income taxes	(22)	154
Net income (loss)	$ (394)	$ 383
Basic earnings per common share		
Income (loss) from continuing operations	$(0.63)	$ 0.47
Discontinued operations, net of income taxes	0.01	(0.03)
Cumulative effect of accounting changes, net of income taxes	(0.04)	0.29
Net income (loss)	$(0.66)	$ 0.73
Diluted earnings per common share		
Income (loss) from continuing operations	$(0.63)	$ 0.46
Discontinued operations, net of income taxes	0.01	(0.03)
Cumulative effect of accounting changes, net of income taxes	(0.04)	0.29
Net income (loss)	$(0.66)	$ 0.72
Basic average common shares outstanding	595	527
Diluted average common shares outstanding	595	538
Dividends declared per common share	$ 0.04	$ 0.22

See accompanying notes.

EL PASO CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS
(In millions, except share amounts)
(Unaudited)

	March 31, 2003	December 31, 2002
ASSETS		
Current assets		
Cash and cash equivalents	$ 1,782	$ 1,591
Accounts and notes receivable		
Customers, net of allowance of $198 in 2003 and $192 in 2002	4,244	5,315
Affiliates	804	798
Other	481	464
Inventory	854	888
Assets from price risk management activities	1,023	1,027
Margin and other deposits on energy trading activities	1,317	1,003
Other	803	838
Total current assets	11,308	11,924
Property, plant and equipment, at cost		
Pipelines	17,928	18,049
Natural gas and oil properties, at full cost	14,792	14,940
Refining, crude oil and chemical facilities	2,263	2,556
Gathering and processing systems	920	1,101
Power facilities	932	959
Other	749	750
	37,584	38,355
Less accumulated depreciation, depletion and amortization	15,105	14,745
Total property, plant and equipment, net	22,479	23,610
Other assets		
Investments in unconsolidated affiliates	5,429	4,907
Assets from price risk management activities	1,793	1,844
Goodwill and other intangible assets, net	1,364	1,370
Other	2,648	2,569
	11,234	10,690
Total assets	$45,021	$46,224

See accompanying notes.

EL PASO CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS — (Continued)
(In millions, except share amounts)
(Unaudited)

	March 31, 2003	December 31, 2002
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Accounts payable		
Trade	$ 3,277	$ 4,699
Affiliates	29	29
Other	578	777
Short-term financing obligations, including current maturities	2,575	2,075
Notes payable to affiliates	221	189
Liabilities from price risk management activities	1,207	1,073
Western Energy Settlement	100	100
Other	1,183	1,408
Total current liabilities	9,170	10,350
Debt		
Long-term financing obligations	17,738	16,106
Notes payable to affiliates	189	201
	17,927	16,307
Other		
Liabilities from price risk management activities	1,370	1,376
Deferred income taxes	3,378	3,576
Western Energy Settlement	816	799
Other	2,128	2,019
	7,692	7,770
Commitments and contingencies		
Securities of subsidiaries		
Preferred interests of consolidated subsidiaries	2,086	3,255
Minority interests of consolidated subsidiaries	165	165
	2,251	3,420
Stockholders' equity		
Common stock, par value $3 per share; authorized 1,500,000,000 shares; issued 605,376,567 shares in 2003 and 605,298,466 shares in 2002	1,816	1,816
Additional paid-in capital	4,441	4,444
Retained earnings	2,524	2,942
Accumulated other comprehensive loss	(523)	(529)
Treasury stock (at cost) 5,941,479 shares in 2003 and 5,730,042 shares in 2002	(207)	(201)
Unamortized compensation	(70)	(95)
Total stockholders' equity	7,981	8,377
Total liabilities and stockholders' equity	$45,021	$46,224

See accompanying notes.

EL PASO CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(In millions)
(Unaudited)

	Quarter Ended March 31, 2003	Quarter Ended March 31, 2002
Cash flows from operating activities		
Net income (loss)	$ (394)	$ 383
Less income (loss) from discontinued operations, net of income taxes	3	(19)
Net income (loss) from continuing operations	(397)	402
Adjustments to reconcile net income (loss) to net cash from operating activities		
Depreciation, depletion and amortization	361	365
Ceiling test charges	—	33
Non-cash (gains) losses from trading and power activities	69	(427)
(Gain) loss on long-lived assets	318	(15)
Undistributed earnings of unconsolidated affiliates	171	283
Deferred income tax expense (benefit)	(172)	96
Cumulative effect of accounting changes	22	(154)
Other non-cash income items	211	150
Working capital changes	(670)	(533)
Non-working capital changes and other	(4)	(120)
Cash provided by (used in) continuing operations	(91)	80
Cash provided by discontinued operations	2	6
Net cash provided by (used in) operating activities	(89)	86
Cash flows from investing activities		
Additions to property, plant and equipment	(717)	(684)
Purchases of interests in equity investments	(1,002)	(28)
Net proceeds from the sale of assets	1,178	493
Net proceeds from the sale of investments	298	19
Net change in restricted cash	(175)	92
Increase in notes receivable from unconsolidated affiliates	(61)	(190)
Other	4	(44)
Cash used in continuing operations	(475)	(342)
Cash used in discontinued operations	(2)	(4)
Net cash used in investing activities	(477)	(346)
Cash flows from financing activities		
Net borrowings under short-term debt and credit facilities	500	32
Payments to retire long-term debt and other financing obligations	(294)	(751)
Net proceeds from the issuance of long-term debt and other financing obligations	1,822	1,378
Dividends paid to common stockholders	(130)	(108)
Decrease in notes payable to unconsolidated affiliates	(48)	(175)
Payments to redeem preferred interests of consolidated subsidiaries	(1,170)	—
Other	77	4
Net cash provided by financing activities	757	380
Increase in cash and cash equivalents	191	120
Less increase in cash and cash equivalents related to discontinued operations	—	2
Increase in cash and cash equivalents from continuing operations	191	118
Cash and cash equivalents		
Beginning of period	1,591	1,149
End of period	$ 1,782	$1,267

See accompanying notes.

EL PASO CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(In millions)
(Unaudited)

	Quarter Ended March 31, 2003	Quarter Ended March 31, 2002
Net income (loss)	$(394)	$ 383
Foreign currency translation adjustments	59	(1)
Unrealized net gains (losses) from cash flow hedging activity		
Unrealized mark-to-market losses arising during period (net of income tax of $63 in 2003 and $135 in 2002)	(103)	(232)
Reclassification adjustments for changes in initial value to settlement date (net of income tax of $32 in 2003 and $54 in 2002)	50	(95)
Other comprehensive income (loss)	6	(328)
Comprehensive income (loss)	$(388)	$ 55

See accompanying notes.

EL PASO CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

1. Basis of Presentation

We prepared this Quarterly Report on Form 10-Q under the rules and regulations of the United States Securities and Exchange Commission. Because this is an interim period filing presented using a condensed format, it does not include all of the disclosures required by generally accepted accounting principles. You should read it along with our 2002 Form 10-K which includes a summary of our significant accounting policies and other disclosures. The financial statements as of March 31, 2003, and for the quarters ended March 31, 2003 and 2002, are unaudited. We derived the balance sheet as of December 31, 2002, from the audited balance sheet filed in our 2002 Form 10-K. In our opinion, we have made all adjustments, all of which are of a normal, recurring nature (except for the items in Notes 2 through 8), to fairly present our interim period results. Due to the seasonal nature of our businesses, information for interim periods may not indicate the results of operations for the entire year. In addition, prior period information presented in these financial statements includes reclassifications which were made to conform to the current period presentation. These reclassifications have no effect on our previously reported net income or stockholders' equity.

2. Summary of Significant Events and Accounting Policies

Liquidity Update

As was discussed more completely in our 2002 Form 10-K, in February 2003, we announced our 2003 Operational and Financial Plan to address liquidity needs in our business activities. The objectives of this plan were to:

- Preserve and enhance the value of our core businesses;
- Exit non-core businesses quickly, but prudently;
- Strengthen and simplify our balance sheet, while maximizing liquidity;
- Aggressively pursue additional cost reductions; and
- Continue to work diligently to resolve litigation and regulatory matters.

So far in 2003, we have accomplished a number of objectives under our plan. More specifically, we have:

- Completed or announced sales of assets for approximately $2.3 billion (see Note 3 for a further discussion of these divestitures);
- Completed financing transactions, consisting of loans and debt issuances totaling $1.9 billion;
- Repaid approximately $2.6 billion of maturing debt and other obligations, including long-term debt retirements of $294 million, the redemption of $980 million of obligations under our Trinity River financing arrangement, the redemption of $297 million of obligations under our Clydesdale financing arrangement, and the contribution of $1 billion to Limestone Electron Trust (Limestone), which used the proceeds to repay $1 billion of Limestone's notes (see Notes 12, 13 and 17 for a further discussion of these actions);
- Entered into a new $3 billion revolving facility that matures in June 2005;
- Purchased the third party equity interest in our Gemstone power investment for $53 million;
- Restructured the obligations under our Clydesdale financing arrangement as a term loan that will amortize over the next two years; and

- Reached an agreement in principle (the Western Energy Settlement) in March 2003, which was designed to resolve our principal exposure relating to the western energy crisis while minimizing the impact on our current liquidity.

In April 2003, we announced the next steps under our plan. These actions include:

- Targeting additional pre-tax cost savings and business efficiencies of $250 million, beyond the previously announced savings of $150 million by the end of 2004;
- Working to recover cash collateral currently committed to our trading, petroleum, refining and other businesses; and
- Reducing our obligations senior to common stock by at least $2.5 billion in 2003.

We believe the accomplishments achieved to date demonstrate our ability to address our liquidity issues and simplify and improve our capital structure. However, a number of factors could influence the timing and ultimate outcome of these efforts.

Significant Accounting Policies Update

Our accounting policies are consistent with those discussed in our 2002 Form 10-K, except as follows:

Accounting for Asset Retirement Obligations. On January 1, 2003, we adopted Statement of Financial Accounting Standards (SFAS) No. 143, *Accounting for Asset Retirement Obligations*. SFAS No. 143 requires that we record a liability for retirement and removal costs of long-lived assets used in our business. This liability is recorded at its estimated fair value, with a corresponding increase to property, plant and equipment. This asset is depreciated over the remaining useful life of the long-lived asset to which that liability relates. An ongoing expense is recognized for changes in the value of the liability as a result of the passage of time, which we record in depreciation, depletion and amortization expense in our income statement. In the first quarter of 2003, we recorded a charge as a cumulative effect of accounting change of approximately $22 million, net of income taxes related to our adoption of SFAS No. 143. We also recorded property, plant and equipment of $192 million and non-current retirement obligations of $222 million as of January 1, 2003. Our asset retirement obligations are associated with our natural gas and oil wells and related infrastructure in our Production segment and our natural gas storage wells in our Pipelines segment. We have obligations to plug wells when production on those wells is exhausted, and we abandon the wells. We currently forecast that these obligations will be met at various times over the next one hundred years, based on the expected natural gas and oil contained in the wells and the estimated timing of plugging and abandoning the wells. The net asset retirement liability as of January 1, 2003 and March 31, 2003, reported in other non-current liabilities in our balance sheet, and the changes in the net liability for the quarter ended March 31, 2003, were as follows (in millions):

Liability at January 1, 2003	$222
Liability settled in 2003	(25)
Accretion expense in 2003	5
Other	(1)
Net liability at March 31, 2003	$201

Had we adopted SFAS No. 143 as of January 1, 2002, our non-current retirement liabilities would have been approximately $200 million as of January 1, 2002, and our income from continuing operations and net income for the quarter ended March 31, 2002, would have been lower by $4 million. Basic and diluted earnings per share for the quarter ended March 31, 2002, would not have been affected.

Accounting for Costs Associated with Exit or Disposal Activities. On January 1, 2003, we adopted SFAS No. 146, *Accounting for Costs Associated with Exit or Disposal Activities*. SFAS No. 146 requires that we recognize costs associated with exit or disposal activities when they are incurred rather than when we commit to an exit or disposal plan. We recognized $31 million of employee severance costs, less income taxes of $8 million, in the first quarter of 2003, of which $21 million had been paid as of March 31, 2003. We also recognized charges of approximately $44 million, less income taxes of $12 million, associated with our liquefied natural gas (LNG) business following our announced plan to minimize our involvement in that business in February 2003. The costs recorded related to amounts paid for canceling our option to charter a fifth ship to transport LNG from supply areas to domestic and international market centers and to restructure the remaining charter agreements. We recorded these costs as operation and maintenance expenses in our income statement and impacted the results in our Merchant Energy, Production and Corporate business segments. As we continue to evaluate our business activities and seek additional cost savings, we expect to incur additional charges that will be evaluated under this accounting standard.

Accounting for Guarantees. On January 1, 2003, we adopted Financial Accounting Standards Board Interpretation (FIN) No. 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others*. FIN No. 45 requires that we record a liability for all guarantees, including financial performance and fair value guarantees, issued after December 31, 2002, at their fair value when they are issued. There was no initial financial statement impact of adopting this standard.

Stock-Based Compensation. We account for our stock-based compensation plans using the provisions of Accounting Principles Board Opinion No. 25 (APB No. 25), *Accounting for Stock Issued to Employees,* and its related interpretations. Had we accounted for our stock option grants using SFAS No. 123, *Accounting for Stock-Based Compensation,* rather than the provisions of APB No. 25, the income and per share impacts of stock-based compensation on our financial statements would have been different. The following shows the impact on net income (loss) and earnings per share had we applied the provisions of SFAS No. 123:

	Quarter Ended March 31,	
	2003	2002
	(In millions, except per common share amounts)	
Net income (loss), as reported	$ (394)	$ 383
Deduct: Total stock-based employee compensation determined under fair value based method for all awards, net of related tax effects	22	41
Pro forma net income (loss)	$ (416)	$ 342
Earnings (losses) per share:		
Basic, as reported	$(0.66)	$0.73
Basic, pro forma	$(0.70)	$0.65
Diluted, as reported	$(0.66)	$0.72
Diluted, pro forma	$(0.70)	$0.64

3. Divestitures

During 2003, we completed or announced the sale of a number of assets as part of our 2003 Operational and Financial Plan. These sales transactions occurred in each of our business segments as follows:

Segment	Proceeds	Pre-tax Gain (Loss)[1]	Significant Asset and Investment Divestitures
	(In millions)		
Completed in the first quarter			
Pipelines	$ 43	$ (1)	• Panhandle gathering system located in Texas • 2.1 percent equity interest in Alliance pipeline and related assets
Production	678	—[2]	• Natural gas and oil properties located in western Canada, New Mexico, Oklahoma and the Gulf of Mexico
Field Services	35	—	• Gathering systems located in Wyoming
Merchant Energy	720	59	• 50 percent equity interest in CE Generation L.L.C. power investment (including the rights to a 50 percent interest in a geothermal development project) • Mt. Carmel power plant • Kladno power project • Corpus Christi refinery • Florida petroleum terminals and tug and barge operations
Corporate and Other	89	(8)	• Coal reserves and properties in West Virginia, Virginia and Kentucky • Aircraft
	$1,565	$ 50	
Announced to date[3]			
Pipelines	$ 10	$ 2	• Helium processing operations in Oklahoma
Field Services	120	21	• Midstream assets in the north Louisiana and Mid-Continent regions
Merchant Energy	830	16	• Petroleum asphalt operations and lease crude business • Eagle Point refinery and related pipeline assets[4] • Enerplus Global Energy Management Company and its financial operations • East Coast Power, LLC[5]
Production	4	—	• Natural gas and oil properties located in the Gulf of Mexico
Corporate and Other	3	(3)	• Aircraft
	$ 967	$ 36	

(1) Amounts do not include asset impairments recognized, if any, at the time we decide to sell the asset. See Notes 6 and 17 for a discussion of impairments taken on long-lived asset and investment divestitures.

(2) We did not recognize gains or losses on these completed sales of natural gas and oil properties because individually they did not significantly alter the relationship between capitalized costs and proved reserves at the time they were sold.

(3) Sales that have been announced, but not completed, are subject to customary regulatory approvals, final sale negotiations and other conditions and are estimates.

(4) We have entered into a non-binding letter of intent to sell these assets for estimated net proceeds of $250 million. In the first quarter of 2003, we recognized an impairment of $350 million on our Eagle Point refinery. See Note 6 for a discussion of this impairment.

(5) East Coast Power is part of our Chaparral investment. See Note 17 for a further discussion of Chaparral. Also, see Note 14 for a discussion of regulatory matters that could impact this transaction.

We evaluate potential asset sales each period to determine if any meet the criteria as held for sale or as discontinued operations under SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*. The more significant criteria we evaluate are whether:

- Management, with the authority to approve the sale, commits to a plan to sell the asset;
- The asset is available for immediate sale in its present condition;
- An active program to locate a buyer and other actions required to complete the sale have been started; and
- The sale of the asset is probable and is expected to be completed within one year.

To the extent that all of these criteria as well as the other requirements of SFAS No. 144 are met, we classify an asset as held for sale or, if appropriate, discontinued operations. For example, our Board of Directors or a designated subcommittee of the Board of Directors is required to approve asset dispositions greater than specified thresholds. Unless specific approval is received by our Board of Directors or their designated subcommittee by the end of the period to commit to a plan to sell an asset, we would not classify it as held for sale or discontinued operations even if it is management's stated intent to sell the asset. In our balance sheet we classified several long-lived assets as held for sale, including (1) Field Services' midstream assets in the north Louisiana region and several of its gathering systems and three processing plants located in Wyoming and (2) Merchant Energy's petroleum asphalt operations and lease crude business and its Florida petroleum terminals and tug and barge operations. The total assets held for sale had net book values in property, plant and equipment of approximately $109 million as of March 31, 2003 and $134 million as of December 31, 2002. These assets were classified as other current assets as of March 31, 2003 and December 31, 2002, since we plan to sell them in the next twelve months.

We continue to evaluate assets we may sell in the future. Recently, we announced that we intend to pursue a sale of our Aruba refinery, our telecommunications business and domestic power assets. These activities are in the early stages and no definitive agreements have been received or approved by our management or Board of Directors. Furthermore, we are not certain what form these possible divestitures may take (e.g. outright sale or joint venture arrangement). We believe it is likely that a decision to sell these assets in the current economic environment will result in future impairments or losses. The amounts of the losses will be based on an estimate of the expected fair value of the assets as determined by market data that becomes available to us as we proceed with the sales process. As of March 31, 2003, our net investment in the Aruba refinery was approximately $1.2 billion (excluding the Aruba coker facility which will have a carrying value, following its consolidation in the second quarter of 2003, of $0.4 billion), and our net investment in our telecommunications business was $0.4 billion (excluding the Lakeside Technology Center which will have a carrying value, following its consolidation and impairment in the second quarter of 2003, of approximately $0.2 billion). See Note 17 for a discussion of our domestic power business which is primarily conducted through our investment in Chaparral and Note 12 for a discussion of our consolidation of Lakeside and the Aruba coker facility.

In March 2002, we sold natural gas and oil properties located in east and south Texas. Net proceeds from these sales were approximately $500 million. We did not recognize a gain or loss on these sales because individually at the time these properties were sold these sales did not significantly alter the relationship between capitalized costs and proved reserves.

4. Western Energy Settlement

On March 20, 2003, we entered into an agreement in principle with a number of public and private claimants, including the states of California, Washington, Oregon and Nevada, to resolve the principal litigation, claims and regulatory proceedings against us and our subsidiaries relating to the sale or delivery of natural gas and electricity from September 1996 to the date of the settlement (referred to as the Western Energy Settlement). As discussed in our 2002 Form 10-K, the settlement will include payments of cash, the issuance of common stock and the delivery of natural gas over a period of 20 years.

The obligation for the settlement was reflected in our balance sheet at $899 million as of December 31, 2002, which represented the overall amount of the settlement of approximately $1,690 million, less a discount (based on a discount rate of 10 percent) of approximately $791 million. During the first quarter of 2003, we recorded $17 million of amortization expense on the discount associated with the settlement obligation, which increased our total obligation to $916 million as of March 31, 2003. This amortization was reflected in our operation and maintenance expense in our income statement.

The calculation of our total settlement obligation required us to use estimates and assumptions based on currently available information. These estimates included the discount rate, the timing of final settlement and the timing of payments made to satisfy obligations. As a result, our estimates and assumptions may change.

5. Ceiling Test Charges

Under the full cost method of accounting for natural gas and oil properties, we perform quarterly ceiling tests to determine whether the carrying value of natural gas and oil properties exceeds the present value of future net revenues, discounted at 10 percent, plus the lower of cost or fair market value of unproved properties, net of related income tax effects.

For the quarter ended March 31, 2002, we recorded ceiling test charges of $33 million, including $10 million for our Brazilian full cost pool and $23 million for other international production operations, primarily in Turkey, based upon the daily posted natural gas and oil prices as of March 31, 2002, adjusted for oilfield or natural gas gathering hub and wellhead price differences, as appropriate.

We use financial instruments to hedge against the volatility of natural gas and oil prices. The impact of these hedges was considered in determining our ceiling test charges and will be factored into future ceiling test calculations. The charges for our international cost pools would not have changed had the impact of these hedges not been included in calculating our first quarter ceiling test charges since we do not significantly hedge our international production activities.

6. Gain (Loss) on Long-Lived Assets

Our gain (loss) on long-lived assets consists of net realized gains and losses on sales of long-lived assets and impairments of long-lived assets. During each of the quarters ended March 31, our gain (loss) on long-lived assets was as follows:

	2003	2002
	(In millions)	
Net realized gain	$ 50	$15
Asset impairments	(368)	—
Gain (loss) on long-lived assets	$(318)	$15

Net Realized Gain

Our net realized gain on sales of long-lived assets for the quarters ended March 31, 2003 and 2002, was $50 million and $15 million. Our 2003 gains were primarily related to the sales of the Corpus Christi refinery and the Florida petroleum terminals and tug and barge operations in our Merchant Energy segment. Partially offsetting the 2003 gains was a loss on the sale of aircraft in our Corporate and Other segment. See Note 3 for a further discussion of these divestitures. Our 2002 gains were primarily related to the sale of pipeline expansion rights in our Pipelines segment and the sale of non-full cost pool assets in our Production segment.

Asset Impairments

We are required to test assets for recoverability whenever events or changes in circumstances indicate that the carrying amount of these assets may not be recoverable. One triggering event that may indicate an asset's carrying amount may not be recoverable is the expectation that it is more likely than not that we will sell or dispose of an asset before the end of its estimated useful life. Based on our intentions as of

March 31, 2003, that we will dispose of some of our assets, we tested those assets for recoverability during the first quarter of 2003 that we believed would more likely than not be sold. As a result of this assessment, we recognized an impairment of $350 million on our Eagle Point refinery and several of our chemical assets in our Merchant Energy segment. We also recorded impairment charges of approximately $18 million in the first quarter of 2003, $9 million of which related to the impairment of our LNG assets in the Merchant Energy segment due to our plan to reduce our involvement in this business and $9 million which related to non-full cost assets in Canada in our Production segment.

7. Other Expenses

Included in other expenses for the quarter ended March 31, 2003, was an $86 million loss on the impairment of notes receivable from our Milford equity investment and accruals on contracts related to that investment. See Note 14 for a further discussion of conditions that led to this impairment. Also included in other expenses in 2003 was a $33 million foreign currency loss resulting from the impact of foreign currency fluctuations on our Euro-denominated debt. During the quarter ended March 31, 2002, other expenses included a $56 million impairment of investment in our Costañera power plant, a cost-based investment in Argentina.

8. Discontinued Operations

Coal Mining Operations

In the latter part of 2002 and the first quarter of 2003, we sold our coal mining operations. These operations consisted of fifteen active underground and two surface mines located in Kentucky, Virginia and West Virginia.

Our coal mining operations have been classified in other current assets and liabilities as discontinued operations in our financial statements for all periods. The summarized financial results of discontinued operations were as follows:

	Quarter Ended March 31,	
	2003	2002
	(In millions)	
Operating results:		
Revenues	$27	$ 67
Costs and expenses	(23)	(97)
Income (loss) before income taxes	4	(30)
Income tax benefit	(1)	11
Income (loss) from discontinued operations, net of income taxes	$ 3	$(19)

	December 31, 2002
	(In millions)
Financial position data:	
Assets of discontinued operations	
Accounts receivable	$ 29
Inventory	14
Property, plant and equipment, net	46
Other	17
Total assets	$106
Liabilities of discontinued operations	
Accounts payable and other	$ 25
Environmental remediation reserve	15
Total liabilities	$ 40

9. Earnings Per Share

We calculated basic and diluted earnings per common share amounts as follows for the quarters ended March 31:

	2003		2002	
	Basic	Diluted	Basic	Diluted
	(In millions, except per common share amounts)			
Income (loss) from continuing operations	$ (375)	$ (375)	$ 248	$ 248
Interest on trust preferred securities and preferred stock dividends, net of income taxes	—	—	—	3
Adjusted income (loss) from continuing operations	(375)	(375)	248	251
Discontinued operations, net of income taxes	3	3	(19)	(19)
Cumulative effect of accounting changes, net of income taxes	(22)	(22)	154	154
Adjusted net income (loss)	$ (394)	$ (394)	$ 383	$ 386
Average common shares outstanding	595	595	527	527
Effect of dilutive securities				
Stock options	—	—	—	2
Restricted stock	—	—	—	—
FELINE PRIDES^{SM}	—	—	—	1
Equity security units	—	—	—	—
Trust preferred securities	—	—	—	8
Convertible debentures	—	—	—	—
Average common shares outstanding[1]	595	595	527	538
Earnings per common share				
Income (loss) from continuing operations	$(0.63)	$(0.63)	$ 0.47	$ 0.46
Discontinued operations, net of income taxes	0.01	0.01	(0.03)	(0.03)
Cumulative effect of accounting changes, net of income taxes	(0.04)	(0.04)	0.29	0.29
Adjusted net income (loss)	$(0.66)	$(0.66)	$ 0.73	$ 0.72

[1] Due to their antidilutive effect on earnings per common share, for 2003, we excluded a total of 16 million shares for all potentially dilutive securities, and for 2002, we excluded a total of 8 million shares for the assumed conversion of convertible debentures.

10. Financial Instruments and Price Risk Management Activities

The following table summarizes the carrying value of our trading and non-trading price risk management assets and liabilities as of March 31, 2003 and December 31, 2002:

	March 31, 2003	December 31, 2002
	(In millions)	
Net assets (liabilities)		
Energy contracts		
Trading contracts[1]	$(146)	$ (59)
Non-trading contracts		
Derivatives designated as hedges	(607)	(500)
Other derivatives	955	959
Total energy contracts	202	400
Interest rate and foreign currency contracts	37	22
Net assets from price risk management activities[2]	$ 239	$ 422

(1) Trading contracts are derivative contracts that are entered into for purposes of generating a profit or benefiting from movements in market prices.

(2) Net assets from price risk management activities include current and non-current assets and current and non-current liabilities from price risk management activities on the balance sheet.

Other derivatives include derivative contracts related to the power restructuring activities of our consolidated subsidiaries of $967 million as of March 31, 2003 and $968 million as of December 31, 2002. Of this amount, $882 million and $878 million relate to a power restructuring transaction at our Eagle Point Cogeneration facility as of March 31, 2003 and December 31, 2002, and $85 million and $90 million relate to a power restructuring transaction at our Capitol District Energy Center Cogeneration Associates plant as of March 31, 2003 and December 31, 2002. The remaining balances in other derivatives, unrealized losses of $12 million and $9 million as of March 31, 2003 and December 31, 2002, relate to derivative positions that no longer qualify as cash flow hedges under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, because they were designated as hedges of anticipated future production on natural gas and oil properties that were sold during 2002.

11. Inventory

Our inventory consisted of the following:

	March 31, 2003	December 31, 2002
	(In millions)	
Current		
Refined products, crude oil and chemicals	$ 600	$ 602
Materials and supplies and other	208	208
Natural gas liquids and natural gas in storage	46	78
Total current inventory	854	888
Non-current		
Dark fiber	5	5
Turbines	219	222
Total non-current inventory[1]	224	227
Total inventory	$1,078	$1,115

(1) We recorded these amounts as other non-current assets in our balance sheet.

12. Debt and Other Credit Facilities

Short-Term Debt and Credit Facilities

At March 31, 2003, our weighted average interest rate on our short-term credit facilities was 2.61%, and at December 31, 2002, it was 2.69%. We had the following short-term borrowings and other financing obligations:

	March 31, 2003	December 31, 2002
	(In millions)	
Current maturities of long-term debt and other financing obligations	$ 575	$ 575
Short-term credit facilities	2,000	1,500
	$2,575	$2,075

Credit Facilities

In April 2003, we entered into a new $3 billion revolving credit facility, with a $1.5 billion letter of credit sublimit, which matures in June 2005. This facility replaces our previous $3 billion revolving credit facility. Our existing $1 billion revolving credit facility, which matures in August 2003, and approximately $1 billion of other financing arrangements (including leases, letters of credit and other facilities) were also amended to conform our obligations to the new $3 billion revolving credit facility. Our $3 billion revolving credit facility, $1 billion revolving credit facility, and the other financing arrangements are secured by our equity in El Paso Natural Gas Company (EPNG), Tennessee Gas Pipeline Company (TGP), ANR Pipeline Company (ANR), Wyoming Interstate Company, ANR Storage Company, and our common and Series C units in El Paso Energy Partners, L.P. These credit facilities and other financing arrangements are also collateralized by our equity in the companies that own the assets that collateralize our Clydesdale financing arrangement. For a discussion of Clydesdale, see Note 13.

EPNG and TGP remain jointly and severally liable for any amounts outstanding under the new $3 billion revolving credit facility through August 19, 2003. Also, EPNG and TGP remain jointly and severally liable under our $1 billion revolving credit facility and as such are liable for any amounts under the facility until its maturity in August 2003. In addition, El Paso CGP Company is no longer a borrower under the $1 billion credit facility.

The revolving credit facilities have a borrowing cost of LIBOR plus 350 basis points and letter of credit fees of 350 basis points. As of March 31, 2003, we had $1.5 billion outstanding under the $3 billion revolving credit facility and $500 million outstanding under the $1 billion revolving credit facility. We have also issued $456 million letters of credit under the $1 billion revolving credit facility.

The availability of borrowings under our credit and borrowing agreements is subject to specified conditions, which we currently meet. These conditions include compliance with the financial covenants and ratios required by those agreements, absence of default under the agreements, and continued accuracy of the representations and warranties contained in the agreements.

Long-Term Debt Obligations

During the first quarter of 2003, we completed several debt financing transactions related to our long-term debt obligations:

Date	Company	Type	Interest Rate	Principal	Net Proceeds[1]	Due Date
				(In millions)		
Issuances						
March	El Paso[2]	Two-year term loan	LIBOR+4.25%	$1,200	$1,149	2004-2005
March	SNG	Senior notes	8.875%	400	385	2010
March	ANR	Senior notes	8.875%	300	288	2010
				$1,900	$1,822	
Retirements						
January	Other	Long-term debt	Various	$ 54	$ 54	2003
February	El Paso CGP	Long-term debt	4.49%	240	240	2004
				$ 294	$ 294	

(1) Net proceeds were primarily used to repay maturing long-term debt, redeem preferred interests of consolidated subsidiaries, repay short-term borrowings and other financing obligations and for general corporate and investment purposes.

(2) We have collateralized this term loan with natural gas and oil reserves of approximately 2.3 trillion cubic feet of gas equivalents. The minimum LIBOR rate is 3.5%. This term loan has scheduled payments of $300 million in each of June 2004 and September 2004 and the $600 million balance in March 2005. Additionally, the loan facility requires us to pay a facility fee equal to 2% per annum on the average daily aggregate outstanding principal amount of the loan. Funds from the term loan were primarily used to retire the Trinity River financing arrangement.

Restrictive Covenants

As part of our new $3 billion revolving credit facility, several of our significant covenants changed. Our ratio of debt to capitalization (as defined in the new revolving credit facility) cannot exceed 75 percent, instead of the previous maximum of 70 percent (as was defined in the prior credit facility agreement). The covenant relating to subsidiary debt was removed. Also, EPNG, TGP, ANR, and upon the maturity of the Clydesdale financing transaction, CIG cannot incur incremental debt if the incurrence of this incremental debt would cause their debt to EBITDA ratio (as defined in the new revolving credit facility) for that particular company to exceed 5 to 1. As of the date of this filing, we were in compliance with these covenants.

As mentioned above, we amended a number of other financing arrangements to conform our obligations to our new $3 billion revolving credit facility. This included amending two operating leases where we provide a guarantee to the lessors for the residual value of the facilities that we lease. The amendments to these operating leases included extending a full guarantee to all of the parties who invested in the lessors, including the equity holder. As a result of the amendments, we will be required to consolidate the lessors in the second quarter of 2003. The two operating leases impacted were:

- The Lakeside Technology Center, a telecommunications facility that provides collocation and cross-connect services; and
- A facility at our Aruba refinery.

When we consolidate the lessors of these facilities, the assets owned by the lessors and the debt that supports the assets will be consolidated in our financial statements. In addition, these assets, once consolidated, will be tested for impairment. Since, at our Lakeside facility, the fair value of the leased asset is less than the debt owed by the lessor, we will be required to write down this asset when we consolidate the lessor. Based on our preliminary analysis, we believe the impact on our financial statements will be as follows (in millions):

Increase in total assets	$645
Less: Impairment charge	133
Net increase in assets	$512
Increase in long-term debt	$645

13. Preferred Interests of Consolidated Subsidiaries

Trinity River. In the first quarter of 2003, we redeemed the entire $980 million of Trinity River (also known as Red River) preferred interests.

Clydesdale. During the first quarter of 2003, we retired approximately $189 million of the third-party member interests in Clydesdale (also known as Mustang) and an additional $8 million in April 2003. Also, in April 2003, we restructured the Clydesdale financing arrangement, and guaranteed the third party equity, which will result in the consolidation of the holder of the preferred member interests in the second quarter of 2003. Consequently, we expect to reflect the debt and equity of the holder of the preferred member interests as debt in our balance sheet and the preferred member interests will be eliminated. The amount of the obligation at March 31, 2003, was $761 million. In addition, this obligation was refinanced in April 2003 as a term loan that will amortize in equal quarterly amounts over the next two years. The term loan remains collateralized by the assets currently supporting the Clydesdale transaction, consisting of a production payment from us, various natural gas and oil properties and our equity in CIG, and is guaranteed by us. We repaid $100 million of this term loan in May 2003.

14. Commitments and Contingencies

Legal Proceedings

Western Energy Settlement. On March 20, 2003, we entered into an agreement in principle (the Western Energy Settlement) with various public and private claimants, including the states of California, Washington, Oregon, and Nevada, to resolve the principal litigation, claims, and regulatory proceedings, which are more fully described below, against us and our subsidiaries relating to the sale or delivery of natural gas and electricity from September 1996 to the date of the Western Energy Settlement. The Western Energy Settlement resulted in an after-tax charge of approximately $650 million in the fourth quarter of 2002. Among other things, the components of the settlement include:

- a cash payment of $100 million;
- a $2 million cash payment from our officer bonus pool;
- the issuance of approximately 26.4 million shares of El Paso common stock;
- delivery to the California border of $45 million worth of natural gas annually for 20 years beginning in 2004;
- a reduction of the pricing of our long-term power supply contracts with the California Department of Water Resources of $125 million over the remaining term of those contracts, which run through the end of 2005;
- payments of $22 million per year for 20 years;
- for a period of five years, EPNG will make available at its California delivery points 3,290 MMcf per day of capacity on a primary delivery point basis;

- for a period of five years, our affiliates will be subject to restrictions in subscribing for new capacity on the EPNG system; and
- no admission of wrongdoing.

The agreement in principle is subject to the negotiation of a formal settlement agreement, portions of which will then be filed with the courts and the FERC for approval. Upon approval, the parties will release us from covered claims that they may have against us and our subsidiaries for the period covered by the Western Energy Settlement, and the litigation, claims, and regulatory proceedings against us and our subsidiaries will be dismissed with prejudice.

California Lawsuits. We and several of our subsidiaries have been named as defendants in fifteen purported class action, municipal or individual lawsuits, filed in California state courts. These suits contend that our entities acted improperly to limit the construction of new pipeline capacity to California and/or to manipulate the price of natural gas sold into the California marketplace. Specifically, the plaintiffs argue that our conduct violates California's antitrust statute (Cartwright Act), constitutes unfair and unlawful business practices prohibited by California statutes, and amounts to a violation of California's common law restrictions against monopolization. In general, the plaintiffs are seeking (i) declaratory and injunctive relief regarding allegedly anticompetitive actions, (ii) restitution, including treble damages, (iii) disgorgement of profits, (iv) prejudgment and post-judgment interest, (v) costs of prosecuting the actions and (vi) attorney's fees. All fifteen cases have been consolidated before a single judge, under two omnibus complaints, one of which has been set for trial in September 2003. All of the class action and municipal lawsuits and all but one of the individual lawsuits will be resolved upon finalization and approval of the Western Energy Settlement. As to the remaining individual lawsuit, on May 8, 2003, a settlement agreement between the plaintiffs and defendants in that case became effective and resolved all disputes between the parties in return for a single payment by us. Pursuant to the settlement, the plaintiff's action will be dismissed with prejudice.

In November 2002, a lawsuit titled *Gus M. Bustamante v. The McGraw-Hill Companies* was filed in the Superior Court of California, County of Los Angeles by several individuals, including Lt. Governor Bustamante acting as a private citizen, against numerous defendants, including our subsidiary EPNG, alleging the creation of artificially high natural gas index prices via the reporting of false price and volume information. This purported class action on behalf of California consumers alleges various unfair business practices and seeks restitution, disgorgement of profits, compensatory and punitive damages, and civil fines. This lawsuit will be resolved upon finalization and approval of the Western Energy Settlement.

In September 2001, we received a civil document subpoena from the California Attorney General, seeking information said to be relevant to the department's ongoing investigation into the high electricity prices in California. We have cooperated in responding to the Attorney General's discovery requests. This proceeding will be resolved upon finalization and approval of the Western Energy Settlement.

In May 2002, two lawsuits challenging the validity of long-term power contracts entered into by the California Department of Water Resources in early 2001 were filed in California state court against 26 separate companies, including our subsidiary El Paso Merchant Energy, L.P. (EPME or Merchant Energy). In general, the plaintiffs allege unfair business practices and seek restitution damages and an injunction against the enforcement of the contract provisions. These cases have been removed to federal court. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

In January 2003, a lawsuit titled *IMC Chemicals v. EPME, et al.* was filed in California state court against us, EPNG and EPME. The suit arises out of a gas supply contract between IMC Chemicals (IMCC) and EPME and seeks to void the Gas Purchase Agreement between IMCC and EPME for gas purchases until December 2003. IMCC contends that EPME and its affiliates manipulated market prices for natural gas and, as part of that manipulation, induced IMCC to enter into the contract. In furtherance of its attempt to void the contract, IMCC repeats the allegations and claims of the California lawsuits described above. EPME intends to enforce the terms of the contract and counterclaim for contract damages. This case was removed to Federal Court. A hearing was held on April 21, 2003 on the respective motions of the El Paso defendants to dismiss, as well as IMCC's motions to remand. A decision is pending. Our costs and legal exposure related to this lawsuit are not currently determinable.

Other Energy Market Lawsuits. The state of Nevada and two individuals filed a class action lawsuit in Nevada state court naming us and a number of our subsidiaries and affiliates as defendants. The allegations are similar to those in the California cases. The suit seeks monetary damages and other relief under Nevada antitrust and consumer protection laws. This lawsuit will be resolved upon finalization and approval of the Western Energy Settlement.

In December 2002, two class action complaints were filed, one in the state court of Oregon and the other in the federal court in the State of Washington, naming El Paso and more than forty other unrelated industry entities. In each case, the complaint makes general allegations that purchasers of natural gas and/or electricity, within the respective state, were overcharged during the period 2000 through 2002 by the defendants, who allegedly withheld supplies of energy, exercised improper control of the energy market and manipulated prices. These lawsuits have since been voluntarily dismissed.

A purported class action suit was filed in federal court in New York City in December 2002 alleging that El Paso, EPME, EPNG, and other defendants manipulated California's natural gas market by manipulating the spot market of gas traded on the NYMEX. Our costs and legal exposure related to this lawsuit are not currently determinable.

In March 2003, the State of Arizona sued us, EPNG, EPME and other unrelated entities on behalf of Arizona consumers. The suit alleges that the defendants conspired to artificially inflate prices of natural gas and electricity during 2000 and 2001. Making factual allegations similar to those alleged in the California cases, the suit seeks relief similar to the California cases as well, but under Arizona antitrust and consumer fraud statutes. Our costs and legal exposure related to this lawsuit are not currently determinable.

In April 2003, Sierra Pacific Resources and its subsidiary, Nevada Power Company filed a lawsuit titled *Sierra Pacific Resources et al. v. El Paso Corporation et. al.,* against us, EPNG, EPTP, EPME and four other non-El Paso defendants. The lawsuit alleges that the defendants conspired to manipulate supplies and prices of natural gas in the California-Arizona border market from 1996 through 2001. The allegations are similar to those raised in the several cases that are the subject of the Western Energy Settlement described above. The plaintiffs allege that they entered into contracts at inappropriately high prices and hedging transactions because of the alleged manipulated prices. They allege that the defendants' activities constituted (1) a violation of the Nevada Unfair Trade Practices Act; (2) fraud; (3) both a conspiracy to violate and a violation of Nevada's RICO Act; and (4) a civil conspiracy. The complaint seeks $150 million in actual damages from all the defendants, plus an additional $450 million in trebled damages. The El Paso defendants were served with the complaint on May 5, 2003.

On April 28, 2003, a class action suit titled *Jerry Egger, et al. v. Dynegy, Inc.,* was filed in California state court. It specifically names us and 19 other non El Paso companies as defendants and alleges a conspiracy to manipulate electricity prices to consumers in nine states in the West Coast Energy Market. The complaint seeks damages on behalf of the electricity end-users in eight of the states, Oregon, Washington, Utah, Nevada, Idaho, New Mexico, Arizona and Montana. The allegations assert the defendants violated the California antitrust statute (the Cartwright Act) and committed unfair business practices in violation of the California Business Code. The complaint seeks actual and treble damages in an unspecified amount, restitution and pre- and post-judgement interest. Our costs and legal exposure related to this lawsuit are not currently determinable.

Shareholder Class Action Suits. Beginning in July 2002, twelve purported shareholder class action suits alleging violations of federal securities laws have been filed against us and several of our officers. Eleven of these suits are now consolidated in federal court in Houston before a single judge. The suits generally challenge the accuracy or completeness of press releases and other public statements made during 2001 and 2002. The twelfth shareholder class action lawsuit was filed in federal court in New York City in October 2002 challenging the accuracy or completeness of our February 27, 2002 prospectus for an equity offering that was completed on June 21, 2002. It has since been dismissed, in light of similar claims being asserted in the consolidated suits in Houston. Four shareholder derivative actions have also been filed. One shareholder derivative lawsuit was filed in federal court in Houston in August 2002. This derivative action generally alleges the same claims as those made in the shareholder class action, has been consolidated with the shareholder class actions pending in Houston and has been stayed. A second shareholder derivative lawsuit was filed in Delaware State Court in October 2002 and generally alleges the same claims as those made in the consolidated shareholder class action lawsuit. A third shareholder derivative suit was filed in state court in Houston in March 2002, and a fourth shareholder derivative suit was filed in state court in Houston in November 2002. The third and fourth shareholder derivative suits both generally allege that manipulation of California gas supply and gas prices exposed El Paso to claims of antitrust conspiracy, FERC penalties and erosion of share value. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

ERISA Class Action Suit. In December 2002, a purported class action lawsuit was filed in federal court in Houston alleging generally that our direct and indirect communications with participants in the El Paso Corporation Retirement Savings Plan included misrepresentations and omissions that caused members of the class to hold and maintain investments in El Paso stock in violation of the Employee Retirement Income Security Act (ERISA). Our costs and legal exposure related to this lawsuit are not currently determinable.

Carlsbad. In August 2000, a main transmission line owned and operated by EPNG ruptured at the crossing of the Pecos River near Carlsbad, New Mexico. Twelve individuals at the site were fatally injured. On June 20, 2001, the U.S. Department of Transportation's Office of Pipeline Safety issued a Notice of Probable Violation and Proposed Civil Penalty to EPNG. The Notice alleged five violations of DOT regulations, proposed fines totaling $2.5 million and proposed corrective actions. EPNG has fully accrued for these fines. The alleged five probable violations of the regulations of the Department of Transportation's Office of Pipeline Safety are: (1) failure to develop an adequate internal corrosion control program, with an associated proposed fine of $500,000; (2) failure to investigate and minimize internal corrosion, with an associated proposed fine of $1,000,000; (3) failure to conduct continuing surveillance on its pipelines and consider, and respond appropriately to, unusual operating and maintenance conditions, with an associated proposed fine of $500,000; (4) failure to follow company procedures relating to investigating pipeline failures and thereby to minimize the chance of recurrence, with an associated proposed fine of $500,000; and (5) failure to maintain elevation profile drawings, with an associated proposed fine of $25,000. In October 2001, EPNG filed a response with the Office of Pipeline Safety disputing each of the alleged violations.

On February 11, 2003, the National Transportation Safety Board (NTSB) conducted a public hearing on its investigation into the Carlsbad rupture at which the NTSB adopted Findings, Conclusions and Recommendations based upon its investigation. In April 2003, the NTSB published its final report. The NTSB stated that it had determined that the probable cause of the August 19, 2000 rupture was a significant reduction in pipe wall thickness due to severe internal corrosion, which occurred because EPNG's corrosion control program "failed to prevent, detect, or control internal corrosion" in the pipeline. The NTSB also determined that ineffective federal preaccident inspections contributed to the accident by not identifying deficiencies in EPNG's internal corrosion control program.

On November 1, 2002, EPNG received a federal grand jury subpoena for documents related to the Carlsbad rupture. EPNG is cooperating with the grand jury.

A number of personal injury and wrongful death lawsuits were filed against EPNG in connection with the rupture. All but one of these suits have been settled, with settlement payments fully covered by insurance. The remaining case is *Geneva Smith, et al. vs. EPEC and EPNG* filed October 23, 2000 in Harris County, Texas. Trial is set to begin on August 11, 2003. In connection with the settlement of the cases, EPNG contributed $10 million to a charitable foundation as a memorial to the families involved. The contribution was not covered by insurance.

Parties to four settled lawsuits have since filed an additional lawsuit titled *Diane Heady et al. v. EPEC and EPNG* in Harris County, Texas on November 20, 2002, seeking an additional $85 million based upon their interpretation of earlier settlement agreements. Parties to another of the settled lawsuits have filed a lawsuit titled *In the Matter of the Appointment of Jennifer Smith* in Eddy County New Mexico on May 7, 2003, seeking an additional $86 million based upon their interpretation of earlier agreements. In addition, plaintiffs' counsel for the settled New Mexico state court cases have notified EPNG that they intend to file suit on behalf of about twenty-three firemen and EMS personnel who responded to the fire and who allegedly have suffered psychological trauma. We have not been served with such a lawsuit. Our costs and legal exposure related to these lawsuits and claims are not currently determinable. However, we believe these matters will be fully covered by insurance.

Grynberg. In 1997, a number of our subsidiaries were named defendants in actions brought by Jack Grynberg on behalf of the U.S. Government under the False Claims Act. Generally, these complaints allege an industry-wide conspiracy to underreport the heating value as well as the volumes of the natural gas produced from federal and Native American lands, which deprived the U.S. Government of royalties. The plaintiff in this case seeks royalties that he contends the government should have received had the volume and heating value of natural gas produced from royalty properties been differently measured, analyzed, calculated and reported, together with interest, treble damages, civil penalties, expenses and future injunctive relief to require the defendants to adopt allegedly appropriate gas measurement practices. No monetary relief has been specified in this case. These matters have been consolidated for pretrial purposes (In re: Natural Gas Royalties *Qui Tam* Litigation, U.S. District Court for the District of Wyoming, filed June 1997). In May 2001, the court denied the defendants' motions to dismiss. Discovery is proceeding. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

Will Price (formerly Quinque). A number of our subsidiaries were named as defendants in *Quinque Operating Company, et al. v. Gas Pipelines and Their Predecessors, et al.*, filed in 1999 in the District Court of Stevens County, Kansas. Quinque has been dropped as a plaintiff and Will Price has been added. This class action complaint alleges that the defendants mismeasured natural gas volumes and heating content of natural gas on non-federal and non-Native American lands. The plaintiff in this case seeks certification of a nationwide class of natural gas working interest owners and natural gas royalty owners to recover royalties that the plaintiff contends these owners should have received had the volume and heating value of natural gas produced from their properties been differently measured, analyzed, calculated and reported, together with prejudgment and postjudgment interest, punitive damages, treble damages, attorney's fees, costs and expenses, and future injunctive relief to require the defendants to adopt allegedly appropriate gas measurement practices. No monetary relief has been specified in this case. Plaintiffs' motion for class certification was denied on April 10, 2003. Our costs and legal exposure related to this lawsuit are not currently determinable.

MTBE. In compliance with the 1990 amendments to the Clean Air Act, we use the gasoline additive, methyl tertiary-butyl ether (MTBE), in some of our gasoline. We also produce, buy, sell and distribute MTBE. A number of lawsuits have been filed throughout the U.S. regarding MTBE's potential impact on water supplies. We are currently one of several defendants in one such lawsuit in New York. The plaintiffs seek remediation of their groundwater and prevention of future contamination, compensatory damages for the costs of replacement water and for diminished property values, as well as punitive damages, attorney's fees, court costs, and, in some cases, future medical monitoring. Our costs and legal exposure related to this lawsuit and claims are not currently determinable.

In addition to the above matters, we and our subsidiaries and affiliates are named defendants in numerous lawsuits and governmental proceedings that arise in the ordinary course of our business.

For each of our outstanding legal matters, we evaluate the merits of the case, our exposure to the matter, possible legal or settlement strategies and the likelihood of an unfavorable outcome. If we determine that an unfavorable outcome is probable and can be estimated, we establish the necessary accruals. As of March 31, 2003, we had approximately $1,033 million accrued for all outstanding legal matters.

Environmental Matters

We are subject to federal, state and local laws and regulations governing environmental quality and pollution control. These laws and regulations require us to remove or remedy the effect on the environment of the disposal or release of specified substances at current and former operating sites. As of March 31, 2003, we had accrued approximately $471 million, including approximately $452 million for expected remediation costs at current and former operated sites and associated onsite, offsite and groundwater technical studies, and approximately $19 million for related environmental legal costs, which we anticipate incurring through 2027.

The high end of our reserve estimates was approximately $674 million and the low end was approximately $470 million, and our accrual at March 31, 2003, was based on the estimated likely reasonable amount of liability. By type of site, our reserves are based on the following estimates of reasonably possible outcomes.

	March 31, 2003	
Sites	**Low**	**High**
	(In millions)	
Operating	$206	$285
Non-Operating	210	323
Superfund	54	66

Below is a reconciliation of our accrued liability as of March 31, 2003 (in millions):

	2003
Balance as of January 1	$498
Additions/adjustments for remediation activities	(16)
Payments for remediation activities	(15)
Other changes, net	4
Balance as of March 31	$471

In addition, we expect to make capital expenditures for environmental matters of approximately $294 million in the aggregate for the years 2003 through 2008. These expenditures primarily relate to compliance with clean air regulations. For 2003, we estimate that our total remediation expenditures will be approximately $41 million, of which $1 million we estimate will be for capital related expenditures. In addition, approximately $33 million of this amount will be expended under government directed clean-up plans. The remaining $7 million will be self-directed or in connection with facility closures.

Internal PCB Remediation Project. Since 1988, TGP, our subsidiary, has been engaged in an internal project to identify and address the presence of polychlorinated biphenyls (PCBs) and other substances, including those on the Environmental Protection Agency's (EPA) List of Hazardous Substances, at compressor stations and other facilities it operates. While conducting this project, TGP has been in frequent contact with federal and state regulatory agencies, both through informal negotiation and formal entry of consent orders. TGP executed a consent order in 1994 with the EPA, governing the remediation of the relevant compressor stations and is working with the EPA and the relevant states regarding those remediation activities. TGP is also working with the Pennsylvania and New York environmental agencies regarding remediation and post-remediation activities at the Pennsylvania and New York stations.

Kentucky PCB Project. In November 1988, the Kentucky environmental agency filed a complaint in a Kentucky state court alleging that TGP discharged pollutants into the waters of the state and disposed of PCBs without a permit. The agency sought an injunction against future discharges, an order to remediate or remove PCBs and a civil penalty. TGP entered into interim agreed orders with the agency to resolve many of the issues raised in the complaint. The relevant Kentucky compressor stations are being remediated under a 1994 consent order with the EPA. Despite TGP's remediation efforts, the agency may raise additional technical issues or seek additional remediation work in the future.

PCB Cost Recoveries. In May 1995, following negotiations with its customers, TGP filed an agreement with the FERC that established a mechanism for recovering a substantial portion of the environmental costs identified in its internal remediation project. The agreement, which was approved by the FERC in November 1995, provided for a PCB surcharge on firm and interruptible customers' rates to pay for eligible costs under the PCB remediation project, with these surcharges to be collected over a defined collection period. TGP has twice received approval from the FERC to extend the collection period, which is now currently set to expire in June 2004. The agreement also provided for bi-annual audits of eligible costs. As of March 31, 2003, TGP has pre-collected PCB costs by approximately $116 million. The pre-collection will be reduced by future eligible costs incurred for the remainder of the remediation project. TGP is required, to the extent actual expenditures are less than the amounts pre-collected, to refund to its customers the unused pre-collection amount, plus carrying charges incurred up to the date of the refunds. As of March 31, 2003, TGP has recorded a regulatory liability (included in other non-current liabilities on our balance sheet) for future refund obligations of approximately $57 million.

Coastal Eagle Point. From May 1999 to March 2001, our Coastal Eagle Point Oil Company received several Administrative Orders and Notices of Civil Administrative Penalty Assessment from the New Jersey Department of Environmental Protection (DEP). All of the assessments are related to alleged noncompliance with the New Jersey Air Pollution Control Act pertaining to excess emissions from the first quarter 1998 through the fourth quarter 2000 reported by our Eagle Point refinery in Westville, New Jersey. The DEP has assessed penalties totaling approximately $1.3 million for these alleged violations. The DEP has indicated a willingness to accept a reduced penalty and a supplemental environmental project. Our Eagle Point refinery has been granted an administrative hearing on issues raised by the assessments. On February 24, 2003, EPA Region 2 issued a Compliance Order based on a 1999 EPA inspection of the refinery's leak detection and repair (LDAR) program. Alleged violations include failure to monitor all components, and failure to timely repair leaking components. During an August 2000 follow-up inspection, the EPA confirmed our Eagle Point refinery had improved its implementation of the program. The Compliance Order requires documentation of compliance with the program. The Company met with the EPA and DEP in March 2003 to discuss the Order and the possibility for a global settlement pursuant to the EPA's refinery enforcement initiative. Global settlements involving other refiners have included civil penalties and addressed LDAR as well as new source review, the benzene standard, and the standard for combustion of refinery fuel gas. On April 25, 2003, our Eagle Point refinery sent a letter to the EPA committing to global settlement discussions. Our Eagle Point refinery expects to resolve both the DEP assessments and the EPA refinery initiative issues.

CERCLA Matters. We have received notice that we could be designated, or have been asked for information to determine whether we could be designated, as a Potentially Responsible Party (PRP) with respect to 60 active sites under the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) or state equivalents. We have sought to resolve our liability as a PRP at these sites through indemnification by third parties and settlements which provide for payment of our allocable share of remediation costs. As of March 31, 2003, we have estimated our share of the remediation costs at these sites to be between $29 million and $41 million. Since the clean-up costs are estimates and are subject to revision as more information becomes available about the extent of remediation required, and because in some cases we have asserted a defense to any liability, our estimates could change. Moreover, liability under the federal CERCLA statute is joint and several, meaning that we could be required to pay in excess of our pro rata share of remediation costs. Our understanding of the financial strength of other PRPs has been considered, where appropriate, in determining our estimated liabilities.

It is possible that new information or future developments could require us to reassess our potential exposure related to environmental matters. We may incur significant costs and liabilities in order to comply with existing environmental laws and regulations. It is also possible that other developments, such as increasingly strict environmental laws and regulations and claims for damages to property, employees, other persons and the environment resulting from our current or past operations, could result in substantial costs and liabilities in the future. As this information becomes available, or other relevant developments occur, we will adjust our accrual amounts accordingly. While there are still uncertainties relating to the ultimate costs we may incur, based upon our evaluation and experience to date, we believe our current reserves are adequate.

Rates and Regulatory Matters

Wholesale Power Customers' Complaints. In late 2001 and 2002, several wholesale power customers filed complaints with the FERC against EPME and other wholesale power marketers (a list of the complaints is included below for which the primary customers are: Nevada Power Co. and Sierra Pacific Power Co. (NPSP), PacifiCorp, City of Burbank, the California Public Utilities Commission and the California Electricity Oversight Board (CPUC/CEOB). These customers entered into contracts with EPME and other wholesale power suppliers for the purchase of power to be delivered in the future. In these complaints, the customers have asked the FERC to reform the contracts they entered into with EPME and other wholesale power marketers on the grounds that they involve rates and terms that are "unjust and unreasonable" or "contrary to" the public interest within the meaning of the Federal Power Act (FPA). EPME and other respondents believe the allegations in the complaint are without merit and have asked the FERC to dismiss these complaints although no assurances of the outcome can be given. In the NPSP matter, the ALJ issued an initial decision concluding that the contracts at issue should not be modified, and the complaints should be dismissed. On April 23, 2003, the FERC held oral argument on the exceptions to the ALJ's initial decision noted by NPSP and the other complainants. In the CPUC/CEOB matter, the ALJ issued an initial decision finding the public interest standard applies to the contract at issue, which finding is consistent with the initial decision of the ALJ in the NPSP case. Oral argument was held on May 15, 2003 on the merits of this complaint and the CPUC/CEOB's exceptions to the ALJ's initial decision concluding the public interest standard of review applied to the complaint. The CPUC/CEOB matter will be fully resolved upon finalization and approval of the Western Energy Settlement. In the PacifiCorp matter, the ALJ issued an initial decision concluding that the complaint filed by PacifiCorp against EPME (and other respondents) should be dismissed with prejudice. The decisions of the ALJs for these matters will be submitted to the FERC for its review. On March 11, 2003, the City of Burbank matter was set for hearing, but then that hearing was held in abeyance pending FERC-directed settlement talks before a specially appointed ALJ.

CPUC Complaint Proceeding. In April 2000, the Public Utilities Commission of the State of California (CPUC) filed a complaint under Section 5 of the Natural Gas Act (NGA) with the FERC alleging that the sale of approximately 1.2 billion cubic feet per day of capacity by EPNG to EPME, both of whom are our wholly owned subsidiaries, raised issues of market power and violation of FERC's marketing affiliate regulations and asked that the contracts be voided. Although the FERC held that EPNG did not violate its marketing affiliate requirements, it established a hearing before an ALJ to address the market power issue. In the spring and summer of 2001, two hearings were held before the ALJ to address the market power issue and, at the request of the ALJ, the affiliate issue. In October 2001, the ALJ issued an initial decision on the two issues, finding that the record did not support a finding that either EPNG or EPME had exercised market power and that accordingly the market power claims should be dismissed. The ALJ found, however, that EPNG had violated FERC's marketing affiliate rule. EPNG and other parties filed briefs on exceptions and briefs opposing exceptions to the October initial decision.

Also in October 2001, the FERC's Office of Market Oversight and Enforcement filed comments stating that the record at the hearings was inadequate to conclude that EPNG had complied with FERC regulations in the transportation of gas to California. In December 2001, the FERC remanded the proceeding to the ALJ for a supplemental hearing on the availability of capacity at EPNG's California delivery points. On September 23, 2002, the ALJ issued his initial decision, again finding that there was no evidence that EPME had exercised market power during the period at issue to drive up California gas prices and therefore recommending that the complaint against EPME be dismissed. However, the ALJ found that EPNG had withheld at least 345 MMcf/d of capacity (and perhaps as much as 696 MMcf/d) from the California market during the period from November 1, 2000 through March 31, 2001. The ALJ found that this alleged withholding violated EPNG's certificate obligations and was an exercise of market power that increased the gas price to California markets. He recommended that the FERC initiate penalty procedures against EPNG. EPNG and others filed briefs on exceptions to the initial decision on October 23, 2002; briefs opposing exceptions were filed on November 12, 2002. This proceeding will be resolved upon finalization and approval of the Western Energy Settlement.

Systemwide Capacity Allocation Proceeding. In July 2001, several of EPNG's contract demand or CD customers filed a complaint against EPNG at the FERC claiming, among other things, that EPNG's full requirements contracts or FR contracts (contracts with no volumetric limitations) should be converted to CD contracts, and that EPNG should be required to expand its system and give demand charge credits to CD customers when it is unable to meet its full contract demands. In July 2001, several of EPNG's FR customers filed a complaint alleging that EPNG had violated the Natural Gas Act and its contractual obligations to them by not expanding its system, at its cost, to meet their increased requirements.

On May 31, 2002, the FERC issued an order on the complaints in which it required that (i) FR service, for all FR customers except small volume customers, be converted to CD service; (ii) firm customers be assigned specific receipt point rights in lieu of their existing systemwide receipt point rights; (iii) reservation charge credits be given to all firm customers for failure to schedule confirmed volumes except in cases of force majeure; (iv) no new firm contracts be executed until EPNG has demonstrated there is adequate capacity on the system; and (v) a process be implemented to allow existing CD customers to turn back capacity for acquisition by FR customers in which process EPNG would remain revenue neutral. These changes were to be made effective November 1, 2002. The order also stated that the FERC expected EPNG to file for certificate authority to add compression to Line 2000 to increase its system capacity by 320 MMcf/d without cost coverage until its next rate case (i.e. January 1, 2006). EPNG had previously informed the FERC that it was willing to add compression to Line 2000 provided it was assured of rate coverage in the next rate case. On July 1, 2002, EPNG and other parties filed for clarification and/or rehearing of the May 31 order.

On September 20, 2002, at the urging of the FR shippers, the FERC issued an order postponing until May 1, 2003 the effective date of the FR conversions. That order also required EPNG to allocate among FR customers (i) the 320 MMcf/d of capacity that will be available from the addition of compression to Line 2000, and (ii) any firm capacity that expires under existing contracts between May 31, 2002, and May 1, 2003, thereby precluding it from reselling that capacity. In total, the September 20 order required that EPNG's FR customers pay only their current aggregate reservation charges for existing unsubscribed capacity, for the 230 MMcf/d of capacity made available in November 2002 by EPNG's Line 2000 project, for the 320 MMcf/d of capacity from the addition of compression to Line 2000, and for all capacity subject to contracts expiring before May 1, 2003.

On April 14, 2003, the FERC issued an order granting a motion by the FR shippers for deferral of the May 1 implementation date pending FERC review of the Western Energy Settlement. The order reset the implementation date to September 1, 2003. Beginning on that date and subject to the substantive requirements of the September 20, 2002 order, EPNG will be required to pay reservation charge credits when it is unable to schedule confirmed volumes except in cases of force majeure. Until September 1, 2003, it is required to pay partial reservation charge credits to CD customers when it is unable to schedule 95 percent of their monthly confirmed volumes except for reasons of force majeure and provided that there is no capacity available from other supply basins on its system.

Several pleadings have been filed in response to the September 20 order, including rehearing requests and requests by several customers to modify the order based on the ALJ's decision in the CPUC Complaint Proceeding discussed above. All such pleadings remain pending before the FERC.

On October 7, 2002, EPNG filed tariff sheets in compliance with the September 20 order to implement a partial demand charge credit for the period November 1, 2002 to May 6, 2003, and to allow California delivery points to be used as secondary receipt points to the extent of its backhaul displacement capabilities. EPNG proposed both a reservation and a usage charge for this service. On December 26, 2002, the FERC issued an order (i) denying EPNG's request to charge existing CD customers a reservation rate for California receipt service for the remaining term of the settlement, *i.e.,* through December 31, 2005; (ii) allowing EPNG to charge its maximum IT rate for the service; (iii) approving EPNG's proposed usage rate for the service until its next rate case; and (iv) requiring it to make a showing that capacity is available for any new shippers utilizing this service. EPNG made a revised tariff filing on January 10, 2003, in compliance with the December 26 order. On January 27, 2003, EPNG filed a request for rehearing on certain aspects of the December 26 order. That request is pending.

Rate Settlement. EPNG's current rate settlement establishes its base rates through December 31, 2005. Under the settlement, EPNG's base rates began escalating annually in 1998 for inflation. EPNG has the right to increase or decrease its base rates if changes in laws or regulations result in increased or decreased costs in excess of $10 million a year. In addition, all of EPNG's settling customers participate in risk sharing provisions. Under these provisions, EPNG received cash payments in total of $295 million for a portion of the risk EPNG assumed from capacity relinquishments by its customers (primarily capacity turned back to it by Southern California Gas Company and Pacific Gas and Electric Company which represented approximately one-third of the capacity of EPNG's system) during 1996 and 1997. The cash EPNG received was deferred, and EPNG recognizes this amount in revenues ratably over the risk sharing period. As of March 31, 2003, EPNG had unearned risk sharing revenues of approximately $24 million and had $10 million remaining to be collected from customers under this provision. Amounts received for relinquished capacity sold to customers, above certain dollar levels specified in EPNG's rate settlement, obligate it to refund a portion of the excess to customers. Under this provision, EPNG refunded a total of $46 million of 2002 revenues to customers during 2002 and the first quarter of 2003. During 2003, EPNG established an additional refund obligation of $10 million. Both the risk and revenue sharing provisions of the rate settlement extend through 2003.

Line 2000 Project. On July 31, 2000, EPNG applied with the FERC for a certificate of public convenience and necessity for its Line 2000 project, which was designed to replace old compression on the system with a converted oil pipeline, resulting in no increase in system capacity. In response to demand conditions on its system, however, EPNG filed in March 2001 to amend its application to convert the project to an expansion project of 230 MMcf/d. On May 7, 2001, the FERC authorized the amended Line 2000 project. EPNG placed the line in service in November 2002 at an approximate capital cost of $185 million. The cost of the Line 2000 conversion will not be included in EPNG's rates until its next rate case, which will be effective on January 1, 2006.

On October 3, 2002, pursuant to the FERC's May 31 and September 20 orders in the systemwide capacity allocation proceeding, EPNG filed with the FERC for a certificate of public convenience and necessity to add compression to its Line 2000 project to increase the capacity of that line by an additional 320 MMcf/d at an estimated capital cost of approximately $173 million for all phases. That application has been protested, and remains pending. In EPNG's request for clarification of the September 20 order, EPNG asked for assurances from the FERC that it will be able to begin cost recovery for this project at the time its next rate case becomes effective. That request remains pending.

Marketing Affiliate NOPR. In September 2001, the FERC issued a Notice of Proposed Rulemaking (NOPR). The NOPR proposes to apply the standards of conduct governing the relationship between interstate pipelines and marketing affiliates to all energy affiliates. The proposed regulations, if adopted by the FERC, would dictate how all our energy affiliates conduct business and interact with our interstate pipelines. In December 2001, we filed comments with the FERC addressing our concerns with the proposed rules. A public hearing was held on May 21, 2002, providing an opportunity to comment further on the NOPR. Following the conference, additional comments were filed by our pipeline subsidiaries and others. At this time, we cannot predict the outcome of the NOPR, but adoption of the regulations in their proposed form would, at a minimum, place additional administrative and operational burdens on us.

Negotiated Rate NOI. In July 2002, the FERC issued a Notice of Inquiry (NOI) that seeks comments regarding its 1996 policy of permitting pipelines to enter into negotiated rate transactions. Several of our pipelines have entered into these transactions over the years, and the FERC is now reviewing whether negotiated rates should be capped, whether or not the "recourse rate" (a cost-of-service based rate) continues to safeguard against a pipeline exercising market power, and other issues related to negotiated rate programs. On September 25, 2002, our pipelines and others filed comments. Reply comments were filed on October 25, 2002. At this time, we cannot predict the outcome of this NOI.

Cash Management NOPR. On August 1, 2002, the FERC issued a NOPR requiring that all cash management or money pool arrangements between a FERC regulated subsidiary and a non-FERC regulated parent must be in writing, and set forth the duties and responsibilities of cash management participants and administrators; the methods of calculating interest and for allocating interest income and expenses; and the restrictions on deposits or borrowings by money pool members. The NOPR also requires specified documentation for all deposits into, borrowings from, interest income from, and interest expenses related to, these arrangements. Finally, the NOPR proposed that as a condition of participating in a cash management or money pool arrangement, the FERC regulated entity maintain a minimum proprietary capital balance of 30 percent, and the FERC regulated entity and its parent maintain investment grade credit ratings. On August 28, 2002, comments were filed. The FERC held a public conference on September 25, 2002, to discuss the issues raised in the comments. Representatives of companies from the gas and electric industries participated on a panel and uniformly agreed that the proposed regulations should be revised substantially and that the proposed capital balance and investment grade credit rating requirements would be excessive. At this time, we cannot predict the outcome of this NOPR.

Also on August 1, 2002, the FERC's Chief Accountant issued an Accounting Release which was effective immediately. The Accounting Release provides guidance on how companies should account for money pool arrangements and the types of documentation that should be maintained for these arrangements. However, it did not address the proposed requirements that the FERC regulated entity maintain a minimum proprietary capital balance of 30 percent and that the entity and its parent have investment grade credit ratings. Requests for rehearing were filed on August 30, 2002. The FERC has not yet acted on the rehearing requests.

Emergency Reconstruction of Interstate Natural Gas Facilities NOPR. On January 17, 2003, the FERC issued a NOPR proposing, in emergency situations, to (1) expand the scope of construction activities authorized under a pipeline's blanket certificate to allow replacement of mainline facilities; (2) authorize a pipeline to commence reconstruction of the affected system without a waiting period; and (3) authorize automatic approval of construction that would be above the normal cost ceiling. Comments on the NOPR were filed on February 27, 2003. At this time, we cannot predict the outcome of this rulemaking.

Pipeline Safety Notice of Proposed Rulemaking. On January 28, 2003, the U.S. Department of Transportation issued a NOPR proposing to establish a rule requiring pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in what the notice refers to as "high consequence areas." The proposed rule resulted from the enactment of the Pipeline Safety Improvement Act of 2002, a new bill signed into law in December 2002. Comments on the NOPR were filed on April 30, 2003. At this time, we cannot predict the outcome of this rulemaking.

FERC Inquiry. On February 26, 2003, we received a letter from the Office of the Chief Accountant at the FERC requesting details of our announcement of 2003 asset sales and plans for our subsidiaries, SNG and ANR, to issue a combined $700 million of long-term notes. The letter requested that we explain how we intended to use the proceeds from SNG's and ANR's issuance of the notes and if the notes will be included in the two regulated companies' capital structure for rate-setting purposes. Our response to the FERC was filed on March 12, 2003, and we fully responded to the request. On April 2, 2003, we received an additional request for information, which we fully responded to on April 15, 2003.

Western Trading Strategies. EPME, our subsidiary, responded on May 22, 2002, to the FERC's May 8, 2002 request in Docket No. PA-02-2, seeking statements of admission or denial with respect to trading strategies designed to manipulate western power markets. EPME provided an affidavit stating that it had not engaged in these trading strategies.

Wash Trade Inquiries. On May 21 and 22, 2002, the FERC issued data requests in Docket PA-02-2, including requests for statements of admission or denial with respect to so-called "wash" or "round trip" trades in western power and gas markets. In May and June 2002, EPME responded, denying that it had conducted any wash or round trip trades (i.e., simultaneous, prearranged trades entered into for the purpose of artificially inflating trading volumes or revenues, or manipulating prices).

On June 7, 2002, we received an informal inquiry from the SEC regarding the issue of round trip trades. Although we do not believe any round trip trades occurred, we submitted data to the SEC on July 15, 2002. On July 12, 2002, we received a federal grand jury subpoena for documents concerning so-called round trip or wash trades. We have complied with these requests.

Price Reporting to Indices. On October 22, 2002, the FERC issued a data request in Docket PA-02-2 to all of the largest North American gas marketers, including EPME, regarding price reporting of transactional data to the energy trade press. We engaged an outside firm to investigate the matters raised in the data request. EPME has provided information regarding its price reporting to indices to the FERC, the Commodities Futures Trading Commission (CFTC), and to the U.S. Attorney in response to their requests. The information provided indicates inaccurate prices were reported to the trade publications. EPME has no evidence that the reporting to the publications resulted in any unrepresentative price index. On March 26, 2003, we announced a settlement between EPME and CFTC of the price reporting matter providing for the payment by EPME of a civil monetary penalty of $20 million, $10 million of which is payable within three years, without admitting or denying the findings made in the CFTC order implementing the agreement. On April 30, 2003, in a new docket PA03-7, the FERC issued an Order Directing Submission of Information with Respect to Internal Processes for Reporting Trading Data, directing certain marketing companies, including EPME, to show that they have corrected their internal processes for reporting trading data to the trade press, or that they no longer sell natural gas at wholesale. The order required the named companies to file within 45 days of the order, to respond to the following questions 1) that employees who participated in manipulations have been disciplined; 2) that the company has a code of conduct in place for reporting price information; 3) all trade data reporting is done by an entity within the company that does not have a financial interest in the published index; and 4) the company is cooperating with any government agency investigation in past price reporting practices. EPME is preparing its response.

Refunds Pricing. On August 13, 2002, the FERC issued a Notice Requesting Comment on Method for Determining Natural Gas Prices for Purposes of Calculating Refunds in ongoing California refund proceedings dealing with sales of electric power in which some of our companies are involved. Referencing a Staff Report also issued on August 13, 2002, the FERC requested comments on whether it should change the method for determining the delivered cost of natural gas in calculating the mitigated market-clearing price in the refund proceeding and, if so, what method should be used. Comments were filed on October 15, 2002. On December 12, 2002, the ALJ issued an Initial Decision, setting forth preliminary calculations of amounts owed. In the aggregate, the ALJ found that $3 billion is owed to natural gas suppliers, offset by an aggregate refund of $1.2 billion associated with prices charged in excess of the mitigated market clearing prices. The FERC issued its order on the Initial Decision on March 26, 2003. The FERC largely adopted the proposed findings of the ALJ in the Initial Decision, which for the most part approved the methodology used in calculating refund liabilities. However, the FERC Commissioners adopted the FERC Staff's findings and recommendations put forth in this refund proceeding, and changed the method for calculating the mitigated market clearing price to use published prices from the production basins, plus fully allocated transport costs, instead of published California border gas prices. The methodology could increase the refund liability. EPME filed a request for rehearing of the March 26, 2003 Order. Upon the finalization and approval of the Western Energy Settlement, claims by many of the claimants in this proceeding for credits against amounts due EPME will be resolved; however, the specific amount of the adjustment is indeterminable at this time. We cannot predict the final outcome of this matter.

Australia. In June 2001, the Western Australia regulators issued a draft rate decision at lower than expected levels for the Dampier-to-Bunbury pipeline owned by EPIC Energy Australia Trust, in which we have a 33 percent ownership interest. EPIC Energy Australia appealed a variety of issues related to the draft decision to the Western Australia Supreme Court. The court directed the regulator to review its position and comply with applicable regulatory law. During the fourth quarter of 2002, events in the business of Epic Energy Australia, including unanticipated cash requirements, made it apparent that a cash equity infusion would be required to refinance the debt of Epic Energy(WA) Nominee Pty. that matures and is payable in full in 2003. With our fourth quarter credit downgrades by the rating agencies and the demands on our liquidity, we concluded that we would not contribute any further equity into our Epic Energy Western Australian investment. As a result, we recognized an impairment of $153 million related to our investment in Epic Energy's Dampier-to-Bunbury pipeline in the fourth quarter of 2002, resulting in an investment of approximately $50 million.

Southwestern Bell Proceeding. We are engaged in proceedings with Southwestern Bell involving disputes regarding our telecommunications interconnection agreement in our metropolitan transport business. In July 2002, we received a favorable ruling from the administrative law judge in Phase 1 of the proceedings. We currently anticipate a determination from the PUC of Texas on the administrative law judge's recommendation no later than July 2003. Despite the favorable ruling from the administrative law judge, the PUC retains the right to affirm or reject the award and any significant rejection of the award could negatively impact our metro transport business. An adverse resolution to the proceeding by the PUC could have a negative impact on our ongoing operations and prospects in this business.

FCC Triennial Review. In this proceeding, the FCC, pursuant to its Congressional mandate, is reexamining the entire list of Unbundled Network Elements (UNEs), including high capacity loops and transport and dark fiber, to determine if any should be removed or qualified. It is possible that the FCC may either eliminate or set more stringent offering guidelines for some of the existing UNE's. Although EPGN has no reason to assume that dark fiber or high capacity loops or transport may be eliminated, any ruling that seriously impaired its ability to access these UNEs would significantly affect its current business model. Further, the FCC has indicated that certain packet/switching technologies/services will not be unbundled. Such a holding, if so ordered, would increase rates on such routes. EPGN has filed comments and an order is expected by the end of the second quarter. It is expected that most of the order will be appealed.

FCC Broadband Docket. The FCC has issued a Notice of Proposed Rule Making (NPRM) for Broadband Service and asked for general comments on a vast array of issues. The NPRM indicates that the FCC is inclined to declare high-speed, DSL internet access service as an information service. This would allow Incumbent Local Exchange Carriers (ILECs) to stop leasing their DSL internet service to third party competitors for resale to customers. ILECs have also submitted proposals that would effectively deregulate all optical level and high-speed copper based services. If the FCC adopted the NPRM proposal, the results would critically affect EPGN's business. EPGN filed initial comments, in conjunction with other ILEC's. EPGN also filed joint reply comments on July 3, 2002, stressing both the illegality of the proposed finding and the national security implications. Certain ILECs are advocating the position that all high capacity copper and fiber lines should be found to be "information services", thereby exempting them from having to lease their lines to EPGN. We have opposed such a holding, which we believe would be unlawful. A decision is expected by the third quarter of 2003.

While the outcome of our outstanding legal matters, environmental matters, and rates and regulatory matters cannot be predicted with certainty, based on current information and our existing accruals, we do not expect the ultimate resolution of these matters to have a material adverse effect on our financial position, operating results or cash flows. However, it is possible that new information or future developments could require us to reassess our potential exposure related to these matters. It is also possible that these matters could impact our debt rating and credit rating. Further, for environmental matters, it is also possible that other developments, such as increasingly strict environmental laws and regulations and claims for damages to property, employees, other persons and the environment resulting from our current or past operations, could result in substantial costs and liabilities in the future. As new information regarding our outstanding legal matters, environmental matters and rates and regulatory matters becomes available, or relevant developments occur, we will review our accruals and make any appropriate adjustments. The impact of these changes may have a material effect on our results of operations, our financial position, and on our cash flows in the period the event occurs.

Other

Enron Bankruptcy. In December 2001, Enron Corp. and a number of its subsidiaries, including Enron North America Corp. and Enron Power Marketing, Inc., (EPMI) filed for Chapter 11 bankruptcy protection in the United States Bankruptcy Court for the Southern District of New York. We had contracts with Enron North America, Enron Power Marketing and other Enron subsidiaries for, among other things, the transportation of natural gas and NGL and the trading of physical natural gas, power, petroleum and financial derivatives.

Our Merchant Energy positions are governed under a master International Swap Dealers Association, Inc. agreement, various master natural gas agreements, a master power purchase and sale agreement, and other commodity agreements. We terminated most of these trading-related contracts, which we believe was proper and in accordance with the terms of these contracts. In October 2002, we filed proofs of claim for our domestic trading positions against Enron trading entities in an amount totaling approximately $318 million. Also in October 2002, our European trading business asserted $20 million in claims against Enron Capital and

Trade Resources Limited which is subject to proceedings in the United Kingdom. In addition, Enron now asserts that Coastal States Trading, Inc. (CSTI) owes them approximate to $3.3 million related to certain terminated petroleum contracts. CSTI disputes this assertion. After considering the cash margins Enron has deposited with us as well as the reserves we have established, our overall Merchant Energy exposure to Enron is $29 million, which is classified as current accounts and notes receivable. We believe this amount is reasonable based on offers received to purchase the claims.

In February 2003, Merchant Energy received a letter from EPMI demanding payment under a March 2001 Power Purchase and Sale Agreement (Agreement) of approximately $46 million. Merchant Energy responded to the February 2003 demand letter denying that any sums were due EPMI under the Agreement. In addition, EPMI has now made demand on us for this sum based on an August 2, 2001 guaranty agreement. EPMI has now filed a lawsuit against Merchant Energy and El Paso in the United States Bankruptcy Court for the Southern District of New York seeking to collect these sums. We have denied liability. This lawsuit has been referred to mediation.

In early May 2003, Enron Broadband Services, Inc. filed a notice of rejection with respect to an IRU agreement granting El Paso Networks, L.L.C. the right to use certain dark fiber in the Denver area. El Paso Network is currently evaluating what actions it may want to take in response to the notice of rejection.

In addition, various Enron subsidiaries had transportation contracts on several of our pipeline systems. Most of these transportation contracts have now been rejected, and our pipeline subsidiaries have filed proofs of claim totaling approximately $137 million. EPNG filed the largest proof of claim in the amount of approximately $128 million, which included $18 million for amounts due for services provided through the date the contracts were rejected and $110 million for damage claims arising from the rejection of its transportation contracts. The September 20 order in the EPNG capacity allocation proceeding discussed in *Rates and Regulatory Matters* above currently prohibits EPNG from remarketing Enron capacity that was not remarketed prior to May 31, 2002. EPNG has sought rehearing of the September 20 order. We have fully reserved for the amounts due through the date the contracts were rejected, and we have not recognized any amounts under these contracts since the rejection date.

As a result of current circumstances surrounding the energy sector, the creditworthiness of several industry participants has been called into question. We have taken actions to mitigate our exposure to these participants; however, should several industry participants file for Chapter 11 bankruptcy protection and contracts with our various subsidiaries are not assumed by other counterparties, it could have a material adverse effect on our financial position, operating results or cash flows.

Cogeneration Facilities. On May 2, 2003, the FERC issued an Order Initiating Investigation into Enron Corporation's ownership of East Coast Power, LLC, which owned three cogeneration facilities. The three facilities are: Cogen Technologies Linden Venture, L.P. ("Linden"), Camden Cogen L.P. ("Camden") and Cogen Technologies NJ Venture ("Bayonne"). The FERC is investigating whether Enron's ownership of the facilities violated restrictions contained in the Public Utility Regulatory Policies Act of 1978 (PURPA) that prohibit an electric utility from owning more than 50 percent of a Qualifying Facility (QF). The FERC asserts that Enron was an electric utility at the time of its ownership as a consequence of its merger with Portland General. We currently believe that from February 1999 to August 1999, Enron owned less than 50 percent of the interests in the facilities due to its partnership with the California Public Employees Retirement System and other third party ownership interests. Our affiliate, Chaparral, currently owns all of the equity interests in Camden and Bayonne and 79.2 percent of the indirect equity interests in Linden and Enron indirectly owns a 1 percent non-voting preferred interest in Linden. Chaparral acquired 49 percent of the interests in the facilities in August of 1999 and the remaining interests in February of 2001. If the FERC finds that Enron's ownership of the facilities violated the ownership restrictions contained in PURPA, it may seek to redetermine applicable rates that the QFs were entitled to charge their customers and order refunds for the period of non-compliance or to impose other penalties within its authority. We intervened in the proceeding before the FERC to protect our interests. It is likely that this proceeding will delay the closing of our announced sale of our interests in East Coast Power.

Broadwing Arbitration. In June 2000, El Paso Global Networks (EPGN), formerly known as El Paso Communications Company, entered into an agreement with Broadwing Communications Services (Broadwing) to construct and maintain a fiber optic telecommunications system from Houston, Texas to Los Angeles, California. In May 2002, EPGN terminated its agreements with Broadwing due to Broadwing's failure to meet its contractual obligations. Broadwing disputed EPGN's right to terminate the agreements. Subsequently, EPGN filed a demand for arbitration and named its arbitrator. We have also sought and obtained injunctive relief to require Broadwing to perform maintenance activity and prohibit it from removing materials or equipment purchased for the project. If it is determined that we properly terminated the contract, Broadwing is required to return all money paid by us which is $62 million and transfer all of the work completed to date free and clear of any liens. The arbitration is scheduled for the fourth quarter of 2003. In the fourth quarter of 2002, we wrote down the value of this long-haul route by $104 million, leaving a total investment of $4 million.

Economic Conditions of Brazil. We have investments in power, pipeline and production projects in Brazil, including an investment in Gemstone, with an aggregate exposure, including financial guarantees, of approximately $1.8 billion. During 2002, Brazil experienced a significant decline in its financial markets due largely to concerns over the refinancing of Brazil's foreign debt and the presidential elections which were completed in late November 2002. These concerns have contributed to significantly higher interest rates on local debt for the government and private sectors, have significantly decreased the availability of funds from lenders outside of Brazil and have decreased the amount of foreign investment in the country. These factors have contributed to a downgrade of Brazil's foreign currency debt rating and a 45 percent devaluation of the local currency against the U.S. dollar since the beginning of 2002. The International Monetary Fund (IMF) announced in the fourth quarter of 2002 a $30 billion loan package for Brazil; however, the release of the majority of the money will depend on Brazil meeting specified fiscal targets set by the IMF in 2003. In addition, Brazil's President or other government representatives may, impose or attempt to impose changes affecting our business, including imposing price controls on electricity and fuels, attempting to force renegotiation of power purchase agreements (PPA's) which are indexed to the U.S. dollar, or attempting to impose other concessions. These developments have delayed and are likely to continue to delay the implementation of projects planned and underway in Brazil. We currently believe that the economic difficulties in Brazil will not have a material adverse effect on our investment in the country, but we continue to monitor the economic situation and potential changes in governmental policy, and are working with the state-controlled utilities in Brazil that are counterparties under our projects' PPA's to maintain the economic returns we anticipated when we made our investments. Future developments in Brazil including forced renegotiations of our existing PPA's or changes in our assumptions related to PPA's where we are seeking extension, may cause us to reassess our exposure and potentially record impairments in the future.

Gemstone, our affiliate, owns a 60 percent interest in a 484 megawatts gas-fired power project, known as the Araucaria project, located near Curitiba, Brazil. Our investment in the Araucaria project was $180 million at March 31, 2003. The project company in which we have an ownership interest has a 20-year PPA with Copel, a regional utility. Copel is approximately 60 percent owned by the State of Parana. After the recent elections in Brazil, the new Governor of the State of Parana publicly characterized the Araucaria project as unfavorable to Copel and the State of Parana and promised a full review of the transaction. Subsequent to this announcement, Copel informed us that they will not pay capacity payments due under the PPA pending that review. Previous payments made under the PPA were made with a reservation of rights with respect to the enforceability of the contract. After meetings with the government as well as new management at Copel to discuss Copel's obligations under the PPA, proved unsuccessful, we were unable to come to a satisfactory resolution of the current issues under the PPA, and we have initiated enforcement of our remedies under the contract, including filing an arbitration proceeding under the International Chamber of Commerce rules in Paris. If we do not prevail in that proceeding, or are not otherwise able to enforce our remedies under the contract, we could be required to impair our investment in the project. Our losses would be limited to our investment. In addition, in the second quarter, we will analyze the fair market value of this investment in conjunction with our acquisition of the third party equity and the consolidation of Gemstone.

We own and consolidate two projects located in Manaus, Brazil in which Gemstone has an indirect minority interest. The first project is a 238 megawatts fuel-oil fired plant known as the Manaus Project with a net book value of plant equipment of $107 million at March 31, 2003 and the second project is a 158 megawatts fuel-oil fired plant known as the Rio Negro Project with a net book value of plant equipment of $111 million at March 31, 2003. The Manaus Project's PPA currently expires in January 2005 and the Rio Negro Project's PPA currently expires in January 2006. In the first quarter of 2003, we began experiencing delays in payment from the purchaser of our power, Manaus Energia S.A. (Manaus Energia). Manaus Energia is an indirect wholly owned subsidiary of Centrais Electricas Brasileiras S. (Eletrobras), a Brazilian federal utility holding company. As of March 31, 2003 our total accounts receivable on these projects is $18 million. In addition, we have filed a lawsuit in the Brazilian courts against Manaus Energia on the Rio Negro Project related to a tariff dispute related to power sales from 1999 to 2001 and have a long-term receivable of $32 million related to this lawsuit. In meetings with Manaus Energia early in the second quarter of 2003. Manaus Energia expressed their desire to renegotiate the current PPAs and have informed us that they view the Manaus Project's PPA as being expired in January 2003, even though a letter agreement executed in May 2002 extended this contract until January 2005. We are continuing negotiations with Manaus Energia in efforts to correct the current payment default issues, to reaffirm the legal standing of the current PPA, and to renegotiate the PPAs to extend their terms by up to seventeen years. If we are unsuccessful in reaching agreement with Manaus Energia regarding compliance with the existing contract terms or are unable to reach an agreement on long-term contract extensions on acceptable terms, we may be required to impair these projects. Our impairment charge would be limited to the amount of the net book value of the plant equipment and the amounts of accounts receivable discussed above as of March 31, 2003.

Gemstone, our affiliate, owns a 50 percent interest in a 409 megawatts dual-fuel-fired power project, known as the Porto Velho Project, located in Porto Velho, Brazil. Our investment in the Porto Velho project was $280 million at March 31, 2003, including guarantees we have issued related to the construction of the project. The Porto Velho Project sells power to Centrais Electicas do Norte do Brasil S.A. (Eletronorte), a wholly owned subsidiary of Eletrobras. The Porto Velho Project has two PPA's. The first PPA is for a term of ten years and relates to the first 64 megawatts phase of the Porto Velho Project. The second PPA is for a term of twenty years and relates to the second 345 megawatts phase of the Porto Velho Project (the Phase 2 PPA). We have recently reached an agreement with the operating management of Eletronorte contained in the Phase 2 PPA, but the senior management of Electronorte has yet to approve the agreement and delays in getting the amendment approved could occur. We will continue to monitoring this situation, and any possibility of having to renegotiate the Porto Velho Project's PPA's. If we do not obtain approval of the PPA's and are forced to renegotiate the prices, we could be required to impair our investment in the project. Our losses would be limited to our investment. In addition, in the second quarter, we will analyze the fair market value of this investment in conjunction with our acquisition of the third party equity and consolidation of Gemstone.

Meizhou Wan Power Project. We own a 25 percent equity interest in a 734 megawatts, coal-fired power generating project, Meizhou Wan Generating, located in Fuzhou, People's Republic of China. Our investment in the project was $56.5 million at March 31, 2003, and we have also issued $34 million in guarantees and letters of credit for equity support and debt service reserves for the project. The project debt is collateralized only by the project's assets and is non-recourse to us. The project declared that it was ready for commercial operations in August 2001; however, the provincial government, who also buys all power generated from the project, has not accepted the project for commercial operations. In October 2002, we reached an interim agreement to allow the plant to operate and sell power at reduced rates until March 2003 while a long-term resolution to existing and past contract terms is negotiated. In March 2003, a letter was forwarded to the Province requesting that the interim agreement be extended until such time that a long term agreement can be reached. The Province has indicated that it will continue to pay the tariff provided for under the Interim Agreement until the new long term tariff is signed. The price the project receives from the sale of power in the interim agreement is expected to be sufficient to provide for the operating costs and debt service of the project, but does not provide for a return on investment to the project's owners. If the project is unable to reach a long-term agreement with the provincial government, with higher rates than in the interim agreement, we could be required to impair our investment in the project, since cash flows from the project would not be sufficient to provide us with a return of our investment, and we may incur additional losses if our guarantees and letters of credit are called upon.

Milford Power Project. We own a 25 percent direct equity interest in a 540 megawatts power plant construction project located in Milford, Connecticut. Chaparral, our affiliate, owns an additional 70 percent interest in this project. The project has been financed through equity contributions, construction financing from lenders that is recourse only to the project and through a construction management services agreement that we funded. This project has experienced significant construction delays, primarily associated with technological difficulties with its turbines including the inability to operate on both gas and fuel oil or to operate at its designed capacity as specified in the construction contract. In October 2001, we entered into a construction management services agreement providing additional funding through October 1, 2002. The construction contractor failed to complete construction of the plant prior to October 1, 2002, in accordance with the terms and specifications of the construction contract. As a result, the project was in default under its construction lending agreement. On October 25, 2002, we entered into a standstill agreement with the construction lending banks that expired on December 2, 2002. We continue to negotiate with the contractor and with the lending banks to attempt to reach agreements on contract disputes, including resolution of liquidated damages that are due to the project under the terms of the construction contract and for successful completion of plant construction, and with the lenders in connection with our obligations under the loan documents. On March 4, 2003, we provided a notice to Milford declaring an event of default under the fuel supply agreement between us and Milford due to non-payment by Milford. On March 6, 2003, Milford received a notice from its lenders stating that the lenders intended to commence foreclosure on the project in accordance with the lending agreement within 30 days. The lenders have not yet exercised this remedy. As a result of the default under the construction lending agreement, we evaluated our investment and recorded an impairment charge of $17 million while Chaparral recorded an impairment charge of $44 million in the fourth quarter of 2002. In April 2003, El Paso's Board of Directors authorized it to enter into settlement negotiations with the lenders to the facility. Based upon the ongoing negotiations with the lenders and the Board's authorization to settle these issues, we recorded an additional charge during the first quarter of 2003 of approximately $86 million. These charges consisted of advances to Milford and other estimated liabilities related to the project.

Berkshire Power Project. We own a 25 percent direct equity interest in a 261 megawatts power plant located in Massachusetts. Chaparral, our affiliate, owns an additional 31.4 percent interest in this project. The construction contractor failed to deliver a plant capable of operating on both gas and fuel oil, or capable of operating at its designed capacity. Berkshire is negotiating with the contractor with respect to its failure to deliver the project in accordance with guaranteed specifications, including fuel oil firing capability. During the third quarter of 2002, the project lenders asserted that Berkshire was in default on its loan agreement. Berkshire is in the process of negotiating with its lenders to resolve disputed contract terms. Failure to reach a satisfactory resolution in these matters could have a material adverse effect on the value of our investment in the project. At March 31, 2003, we had an investment in Berkshire of $7 million, receivables from Berkshire of $28 million and derivatives with Berkshire of $17 million associated with a subordinated fuel agreement and management services agreement. At March 31, 2003, Chaparral's investment was $4 million. We continue to discuss settlement opportunities with our construction contractor. The ultimate resolution of these issues will be considered in the determination of whether any of these investments in and receivables from Berkshire will be impaired in the future.

Cases

The California cases discussed above are five filed in the Superior Court of Los Angeles County *(Continental Forge Company, et al v. Southern California Gas Company, et al,* filed September 25, 2000*; *Berg v. Southern California Gas Company, et al,* filed December 18, 2000*; *County of Los Angeles v. Southern California Gas Company, et al,* filed January 8, 2002*; *The City of Los Angeles, et al v. Southern California Gas Company, et al* and *The City of Long Beach, et al v. Southern California Gas Company, et al,*

*Cases to be dismissed upon finalization and approval of the Western Energy Settlement.

both filed March 20, 2001*); two filed in the Superior Court of San Diego County *(John W.H.K. Phillip v. El Paso Merchant Energy;* and *John Phillip v. El Paso Merchant Energy,* both filed December 13, 2000*); and two filed in the Superior Court of San Francisco County *(Sweetie's et al v. El Paso Corporation, et al,* filed March 22, 2001*; and *California Dairies, Inc., et al v. El Paso Corporation, et al,* filed May 21, 2001); and one filed in the Superior Court of the State of California, County of Alameda *(Dry Creek Corporation v. El Paso Natural Gas Company, et al,* filed December 10, 2001*); and five filed in the Superior Court of Los Angeles County *(The City of San Bernardino v. Southern California Gas Company, et al; The City of Vernon v. Southern California Gas Company; The City of Upland v. Southern California Gas Company, et al; Edgington Oil Company v. Southern California Gas Company, et al; World Oil Corporation, et al. v. Southern California Gas Company, et al,* filed December 27, 2002*). The two long-term power contract lawsuits are *James M. Millar v. Allegheny Energy Supply Company, et al.* filed May 13, 2002 in the Superior Court, San Francisco County, California and *Tom McClintock et al. v. Vikram Budhrajaetal* filed May 1, 2002 in the Superior Court, Los Angeles County, California. The cases referenced in Other Energy Market Lawsuits are: *The State of Nevada, et al. v. El Paso Corporation, El Paso Natural Gas Company, El Paso Merchant Energy Company, et al.* filed November 2002 in the District Court for Clark County, Nevada*; *Sharon Lynn Lodewick v. Dynegy, Inc. et al.* filed December 16, 2002 in the Circuit Court for the County of Multnomah, State of Oregon; *Nick A. Symonds v. Dynegy, Inc. et al.* filed December 20, 2002 in the United States District Court for the Western District of Washington, Seattle; *Henry W. Perlman, et al. v. San Diego Gas & Electric et al.* filed December 2002, in the United States District Court, Southern District of New York. *State of Arizona v El Paso Corporation, El Paso Natural Gas Company, El Paso Merchant Energy Company, et al.* filed March 10, 2003 in the Superior Court, Maricopa County, Arizona. Sierra Pacific Resources et. al. v. El Paso Corporation et. al., filed April 21, 2003 in the United States District Court for the District of Nevada.

The purported shareholder class actions filed in the U.S. District Court for the Southern District of Texas, Houston Division, are: *Marvin Goldfarb, et al v. El Paso Corporation, William Wise, H. Brent Austin, and Rodney D. Erskine,* filed July 18, 2002; *Residuary Estate Mollie Nussbacher, Adele Brody Life Tenant, et al v. El Paso Corporation, William Wise, and H. Brent Austin,* filed July 25, 2002; *George S. Johnson, et al v. El Paso Corporation, William Wise, and H. Brent Austin,* filed July 29, 2002; *Renneck Wilson, et al v. El Paso Corporation, William Wise, H. Brent Austin, and Rodney D. Erskine,* filed August 1, 2002; and *Sandra Joan Malin Revocable Trust, et al v. El Paso Corporation, William Wise, H. Brent Austin, and Rodney D. Erskine,* filed August 1, 2002; *Lee S. Shalov, et al v. El Paso Corporation, William Wise, H. Brent Austin, and Rodney D. Erskine,* filed August 15, 2002; *Paul C. Scott, et al v. El Paso Corporation, William Wise, H. Brent Austin, and Rodney D. Erskine,* filed August 22, 2002; *Brenda Greenblatt, et al v. El Paso Corporation, William Wise, H. Brent Austin, and Rodney D. Erskine,* filed August 23, 2002; *Stefanie Beck, et al v. El Paso Corporation, William Wise, and H. Brent Austin,* filed August 23, 2002; *J. Wayne Knowles, et al v. El Paso Corporation, William Wise, H. Brent Austin, and Rodney D. Erskine,* filed September 13, 2002; *The Ezra Charitable Trust, et al v. El Paso Corporation, William Wise, Rodney D. Erskine and H. Brent Austin,* filed October 4, 2002. The purported shareholder action filed in the Southern District of New York is *IRA F.B.O. Michael Conner et al v. El Paso Corporation, William Wise, H. Brent Austin, Jeffrey Beason, Ralph Eads, D. Dwight Scott, Credit Suisse First Boston, J.P. Morgan Securities,* filed October 25, 2002.

The shareholder derivative actions filed in Houston are *Grunet Realty Corp. v. William A. Wise, Byron Allumbaugh, John Bissell, Juan Carlos Braniff, James Gibbons, Anthony Hall Jr., Ronald Kuehn Jr., J. Carleton MacNeil Jr., Thomas McDade, Malcolm Wallop, Joe Wyatt and Dwight Scott,* filed August 22, 2002. *John Gebhart v. Byron Allumbaugh, John Bissell, Juan Carlos Braniff, James Gibbons, Anthony Hall Jr., Ronald Kuehn Jr., J. Carleton MacNeil Jr., Thomas McDade, Malcolm Wallop, Joe Wyatt and William Wise,* filed March 2002; *Marilyn Clark v. El Paso Natural Gas, El Paso Merchant Energy, Byron Allumbaugh, John Bissell, Juan Carlos Braniff, James Gibbons, Anthony Hall Jr., Ronald Kuehn, Jr., J. Carleton MacNeil, Jr., Thomas McDade, Malcolm Wallop, Joe Wyatt and William Wise* filed in November 2002. The shareholder derivative lawsuit filed in Delaware is *Stephen Brudno et al v. William A. Wise et al* filed in October 2002.

The customer complaints filed at the FERC against EPME and other wholesale power marketers are: *Nevada Power Company and Sierra Pacific Power Company vs. El Paso Merchant Energy, L.P.; California*

Public Utilities Commission vs. Sellers of Long-Term Contracts to the California Department of Water and California Electricity Oversight Board vs. PacifiCorp vs. El Paso Merchant Energy, L.P., and City of Burbank, California vs. Calpine Energy Services, L.P., Duke Energy Trading and Marketing, LLC, El Paso Merchant Energy.

The ERISA Class Action Suit is *William H. Lewis III v. El Paso Corporation, H. Brent Austin and unknown fiduciary defendants 1-100.*

15. Capital Stock

On April 29, 2003, we declared a quarterly dividend of $0.04 per share on our common stock, payable on July 7, 2003, to stockholders of record on June 6, 2003. Also, during the quarter ended March 31, 2003, we paid dividends of $130 million to common stockholders, and El Paso Tennessee Pipeline Co., our subsidiary, paid dividends of approximately $6 million on its Series A cumulative preferred stock, which is 8¼% per annum (2.0625% per quarter).

16. Segment Information

We segregate our business activities into four operating segments: Pipelines, Production, Field Services and Merchant Energy. These segments are strategic business units that provide a variety of energy products and services. They are managed separately as each business unit requires different technology, operational and marketing strategies. In the second quarter of 2002, we reclassified our historical coal mining operations from our Merchant Energy segment to discontinued operations in our financial statements. Merchant Energy's results for the period ended March 31, 2002, were restated to reflect this change.

We use earnings before interest expense and income taxes (EBIT) to assess the operating results and effectiveness of our business segments. We define EBIT as operating income, adjusted for several items, including: equity earnings from unconsolidated affiliates, minority interests of consolidated, but less than wholly owned operating subsidiaries and other miscellaneous non-operating items. Items that are not included in this measure are financing costs, including interest and debt expense, return on preferred interests of consolidated subsidiaries, income taxes, discontinued operations and the impact of accounting changes. We believe this measurement is useful to our investors because it allows them to evaluate the effectiveness of our businesses and operations and our investments from an operational perspective. This measurement may not be comparable to measurements used by other companies and should not be used as a substitute for net income or other performance measures such as operating income or operating cash flow. The reconciliations of EBIT to income (loss) from continuing operations are presented below:

	Quarter Ended March 31,	
	2003	2002
	(In millions)	
Total EBIT	$(124)	$ 713
Interest and debt expense	(345)	(307)
Return on preferred interests of consolidated subsidiaries	(39)	(40)
Income taxes	133	(118)
Income (loss) from continuing operations	$(375)	$ 248

The following are our segment results as of and for the quarters ended March 31:

	Quarter Ended March 31, 2003					
	Pipelines	Production	Field Services	Merchant Energy	Corporate & Other[(1)]	Total
	(In millions)					
Revenues from external customers	$723	$ 91	$402	$2,792[(2)]	$ 10	$4,018
Intersegment revenues	31	504	156	(628)[(2)]	(63)	—
Operating income (loss)	$384	$235	$ —	$ (514)	$(44)	$ 61
Earnings (losses) from unconsolidated affiliates	43	6	28	(176)	—	(99)
Minority interest in consolidated subsidiaries	—	—	(1)	2	—	1
Other income	6	3	—	21	9	39
Other expense	(4)	—	—	(89)	(33)	(126)
EBIT	$429	$244	$ 27	$ (756)	$(68)	$ (124)

(1) Includes our Corporate and telecommunication activities and eliminations of intercompany transactions. Our intersegment revenues, along with our intersegment operating expenses, were incurred in the normal course of business between our operating segments. We record an intersegment revenue elimination, which is the only elimination included in the "Other" column, to remove intersegment transactions.

(2) Merchant Energy revenues take into account the adoption of a consensus reached on EITF Issue No. 02-3, *Issues Related to Accounting for Contracts Involved in Energy Trading and Risk Management Activities*, which requires us to report all physical sales of energy commodities in our energy trading activities on a net basis as a component of revenues. See our 2002 Form 10-K regarding the adoption of EITF Issue No. 02-3.

	Quarter Ended March 31, 2002					
	Pipelines	Production	Field Services	Merchant Energy	Corporate & Other[(1)]	Total
	(In millions)					
Revenues from external customers	$647	$155	$274	$2,677[(2)]	$ 12	$3,765
Intersegment revenues	56	395	266	(656)[(2)]	(61)	—
Operating income (loss)	$357	$175	$ 38	$ 455	$(13)	$1,012
Earnings (losses) from unconsolidated affiliates	36	—	15	(276)	2	(223)
Minority interest in consolidated subsidiaries	—	—	(2)	(50)	—	(52)
Other income	6	1	—	27	8	42
Other expense	—	—	—	(63)	(3)	(66)
EBIT	$399	$176	$ 51	$ 93	$ (6)	$ 713

(1) Includes our Corporate and telecommunication activities and eliminations of intercompany transactions. Our intersegment revenues, along with our intersegment operating expenses, were incurred in the normal course of business between our operating segments. We record an intersegment revenue elimination, which is the only elimination included in the "Other" column, to remove intersegment transactions.

(2) Merchant Energy revenues take into account the adoption of a consensus reached on EITF Issue No. 02-3, *Issues Related to Accounting for Contracts Involved in Energy Trading and Risk Management Activities*, which requires us to report all physical sales of energy commodities in our energy trading activities on a net basis as a component of revenues. See our 2002 Form 10-K regarding the adoption of EITF Issue No. 02-3.

Total assets by segment are presented below:

	March 31, 2003	December 31, 2002
	(In millions)	
Pipelines	$15,015	$14,802
Production	7,780	8,057
Field Services	2,765	2,680
Merchant Energy	15,154	16,308
Corporate and other	4,307	4,271
Total segment assets	45,021	46,118
Discontinued operations	—	106
Total consolidated assets	$45,021	$46,224

17. Investments in Unconsolidated Affiliates and Related Party Transactions

We hold investments in affiliates which we account for using the equity method of accounting. Summarized financial information of our proportionate share of unconsolidated affiliates below includes affiliates in which we hold an interest of 50 percent or less, as well as those in which we hold greater than a 50 percent interest. Our proportional share of the net income of the unconsolidated affiliates in which we hold a greater than 50 percent interest was $9 million and $10 million for the quarters ended March 31, 2003 and 2002.

	Quarter Ended March 31, 2003	Quarter Ended March 31, 2002
	(In millions)	
Operating results data:		
Operating revenues	$ 792	$ 453
Operating expenses	549	303
Income from continuing operations	120	43
Net income	120	43

Our income statement reflects our earnings (losses) from unconsolidated affiliates. This amount includes income or losses directly attributable to the net income or loss of our equity investments as well as impairments and other adjustments to income we record. For the quarters ended March 31, 2003 and 2002, we recorded losses from unconsolidated affiliates of $99 million and $223 million, which were net of impairment charges related to our investments in unconsolidated affiliates and gains and losses on sale of investments of $217 million in 2003 and $286 million in 2002. In the first quarter of 2003, we recorded an impairment charge of $207 million related to our Chaparral investment. See our discussion of the events that led to this impairment under *Chaparral* below. In the first quarter of 2002, we recorded impairment charges of $286 million related to our Agua del Cajon and CAPSA/CAPEX investments due to weak economic conditions in Argentina. See Note 7 for a discussion of an impairment on our cost-based investment in Argentina.

We enter into a number of transactions with our unconsolidated affiliates in the ordinary course of conducting our business. The following table shows revenues, income and expenses incurred between us and our unconsolidated affiliates for the quarters ended March 31:

	2003	2002
	(In millions)	
Operating revenue	$(65)	$62
Other revenue — management fees	3	46
Cost of sales	32	24
Reimbursement for operating expenses	47	39
Other income	3	3
Interest income	5	12
Interest expense	(3)	14

Gemstone

As discussed more completely in our 2002 Form 10-K, we entered into the Gemstone investment in 2001 to finance five major power plants in Brazil. The following summarizes our overall investment in Gemstone:

	March 31, 2003	December 31, 2002
	(In millions)	
Equity investment	$ 670	$ 663
Debt securities payable	(122)	(122)
Credit facility receivable	8	25
Credit facility payable	(75)	—
Net investment	$ 481	$ 566
Minority interest	$(310)	$(304)

We have a credit facility with Gemstone that allows us to borrow amounts from Gemstone related to project financings obtained by Gemstone. We owed Gemstone $75 million as of March 31, 2003 under this facility, which carries a variable interest rate that was 1.8 percent at March 31, 2003.

We accounted for our investment in Gemstone using the equity method of accounting as of March 31, 2003, since we did not have the ability to exercise control over the entity. In April 2003, we purchased all of Rabobank's third party equity interest in Gemstone for approximately $53 million. As a result, we will begin consolidating Gemstone during the second quarter of 2003. At that time, we will record the acquired assets and liabilities at their fair values. Any excess of the amounts paid over the fair values of the net assets acquired will be reflected in our balance sheet as goodwill. Goodwill is not amortized, but is tested periodically for impairment. Had we consolidated Gemstone in our balance sheet as of March 31, 2003, our total assets would have been higher by $0.6 billion, our total liabilities would have been higher by $0.9 billion, (including debt of $1.0 billion, other liabilities of $0.1 billion and a reduction of net intercompany payables of $0.2 billion,) and our minority interest of consolidated subsidiaries would have been lower by $0.3 billion. These amounts are based on the carrying value of Gemstone's assets and liabilities as of March 31, 2003. The actual amounts recorded as fair values for the individual assets and liabilities when we consolidate Gemstone will be based on a number of factors, including economic conditions in Brazil and events specific to each of our projects and could be significantly different than the amounts presented above. These conditions are discussed more fully in Note 14.

Chaparral

As discussed more completely in our 2002 Form 10-K, we entered into our Chaparral investment (also referred to as Electron) in 1999 to expand our domestic power generation business. As of December 31, 2002, we owned 20 percent of Chaparral, with the remaining 80 percent owned by Limestone. In March 2003, we contributed $1 billion to Limestone. Limestone then used these proceeds to pay off notes that Limestone had issued to originally invest in Chaparral. These notes matured on March 17, 2003. Following our $1 billion investment, our effective ownership interest in Chaparral (both direct ownership and indirectly through our ownership interest in Limestone) increased to 90 percent. The following summarizes our overall investment in Chaparral (including our Limestone investment):

	March 31, 2003	December 31, 2002
	(In millions)	
Equity investment	$1,047	$ 256
Notes receivable	307	323
Credit facilities receivable[1]	448	377
Debt securities payable	(32)	(79)
Contingent interest promissory notes payable	(166)	(173)
Total net investment	$1,604	$ 704

[1] This facility earns interest at a variable rate based on LIBOR. This rate was 1.8 percent at March 31, 2003 and 1.9 percent at December 31, 2002.

As a result of our additional investment in Limestone, coupled with a number of developments including a general decline in power prices, declines in counterparty credit ratings, the decline in our own credit ratings, adverse developments at several projects wholly or partially owned by Chaparral, our exit from the power contract restructuring business and generally weaker economic conditions in the unregulated power industry, we determined that we should evaluate, as of March 31, 2003, whether our total investment in Chaparral was less than the fair value of the investment. Furthermore, we evaluated whether any declines that resulted from our analysis would be considered temporary (or not expected to turn around within the next nine to twelve months). Based on our analysis, we determined that the fair value of our total investment in Chaparral, which was based on discounted expected cash flows of Chaparral's underlying assets and liabilities, was not sufficient to recover our investment. As a result, we recorded an impairment of our investment in Chaparral of $207 million, before income taxes, during the quarter ended March 31, 2003.

We continue to account for our investment in Chaparral and in Limestone using the equity method of accounting since we do not have the ability to exercise control over either entity. This accounting did not change when we acquired the additional interest in Limestone because, despite our higher ownership interest, our rights versus those of the third party investor did not change. In March 2003, we notified Limestone's certificate holders that we would exercise our rights under the partnership agreement to purchase all of the remaining third party equity in Limestone for a negotiated price of $175 million. We expect that this transaction will occur during the second quarter of 2003. The price we will pay the third party equity holder is based on the terms of the Limestone agreements. Under the terms of these agreements, we had the option to either provide for a payment to the third party equity holder in exchange for their remaining interests, or allow the third party equity holders to sell the assets of Chaparral, the proceeds of which would first be applied to the payment of the agreed amount to them. If we had elected to allow the third party equity to exercise their liquidation rights, Limestone would control the liquidation process and would not necessarily have been motivated to achieve that maximum value for the assets. In order to protect our interests, maximize the recoverable value of the assets, and obtain the flexibility to manage the assets of Chaparral, regardless of whether these assets are ultimately sold or held and used in our ongoing business, we chose to redeem the third party equity holder's interests for the agreed amount.

Upon our acquisition of the remaining interest in Limestone, we will effectively own 100 percent of Chaparral and will control all of its activities. As a result, we will consolidate Chaparral at that time. Upon consolidation, we will record the acquired assets and liabilities at their fair values. Any excess of the amounts paid over the fair values of the net assets acquired will be reflected in our balance sheet as goodwill. Goodwill is not amortized, but is tested periodically for impairment. Had we consolidated Chaparral in our balance sheet as of March 31, 2003, our total assets would have been higher by $1.6 billion, and our total liabilities would have been higher by $1.6 billion, including project debt of $1.5 billion. These amounts are based on the carrying value of Chaparral's assets and liabilities as of March 31, 2003, considering also the impairment charge we took during the first quarter of 2003, assuming it was allocated to Chaparral's assets and liabilities. The fair values of the individual assets and liabilities when we consolidate Chaparral will be based on a number of factors, including economic conditions in the power industry at that time, interest rates and estimated future natural gas and power market prices, and will be affected by other events that occur between now and that date. As a result, the actual impact to our financial statements will be different than the amounts presented above. Additionally, the estimation of fair value may not reflect the ultimate sales price of any of these assets and, as a result, future gains or losses may arise upon the disposition of these assets. For a discussion of events that could impact the Linden facility that is owned by Chaparral, see Note 14.

We have entered into a number of transactions with Chaparral and its subsidiaries, including providing management and administrative services, capital contributions and being a party to a number of commercial contracts. These transactions are more fully described in our 2002 Form 10-K.

El Paso Energy Partners

A subsidiary in our Field Services segment serves as the general partner of El Paso Energy Partners, a master limited partnership that has limited partnership units that trade on the New York Stock Exchange. On May 1, 2003, El Paso Energy Partners announced that it will begin doing business effective May 15, 2003, as GulfTerra Energy Partners, L.P.

We currently own 11,674,245 of the partnership's common units, the one percent general partner interest, all of the Series B preference units and all of the Series C units. At March 31, 2003, our common units had a market value of $362 million, our preference units had a liquidation value of $161 million, and our Series C units had a value of $347 million. In April 2003, we contributed approximately $1 million of our Series B preference units to El Paso Energy Partners. This contribution was made in order for us to maintain our one percent general partner interest as a result of a common unit offering completed by the partnership.

Our segments also conduct transactions in the ordinary course of business with El Paso Energy Partners, including sales of natural gas and operational services. During the quarter ended March 31, 2003, our Field Services segment recognized revenues from El Paso Energy Partners of $5 million. In the first quarters of 2003 and 2002, Field Services also recognized cost of sales of $17 million and $14 million and was reimbursed $24 million and $9 million for expenses incurred on behalf of the partnership. In addition, during the quarters ended March 31, 2003 and 2002, our Merchant Energy segment recognized revenues of $10 million and $7 million, and cost of sales of $11 million and $3 million related to transactions with El Paso Energy Partners. In the first quarter of 2002, our Production segment also recognized revenues of $1 million and recognized cost of sales of $2 million in the first quarter of 2003 and $1 million in the first quarter of 2002. For a further discussion of our relationships with El Paso Energy Partners, see our 2002 Form 10-K.

18. New Accounting Pronouncements Issued But Not Yet Adopted

In January 2003, the Financial Accounting Standards Board issued FIN No. 46, *Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51.* This interpretation defines a variable interest entity as a legal entity whose equity owners do not have sufficient equity at risk and/or a controlling financial interest in the entity. This standard requires that companies consolidate a variable interest entity if it is allocated a majority of the entity's losses and/or returns, including fees paid by the entity. The provisions of FIN No. 46 are effective for all variable interest entities created after January 31, 2003, and are effective on July 1, 2003, for all variable interest entities created before January 31, 2003.

We currently have interests in and consolidate several entities in which third party investors hold preferred interests. The preferred interests held by the third party investors are reflected in our balance sheet as preferred interests of consolidated subsidiaries. The third party investors are capitalized with five percent equity, which is held by banks in these arrangements, and 95 percent debt. We believe we would consolidate these third party investors under these arrangements because (i) the equity investment in these third party investors is less than the specified 10 percent of total capitalization of the investors and (ii) the rights of the third party investors to expected residual returns from these arrangements is limited. When we consolidate these third party investors, the minority interest that is currently classified as preferred interests of consolidated subsidiaries will be classified as long-term debt. At this time, we believe the holder of the preferred stock of our consolidated subsidiary, Coastal Securities Company Limited, will be impacted by this standard. We believe the impact on our financial statements as a result of implementing this standard will be (in millions):

Decrease in preferred interests of consolidated subsidiaries	$100
Increase in long-term debt	$100

We have a number of other financial interests that would have been affected by this standard, but as a result of actions taken during the first quarter of 2003, or actions we will take in the second quarter of 2003, including amending and restructuring the underlying agreements, these financial interests will be consolidated prior to our required adoption of this standard. The financial interests affected by these actions include:

- Operating leases with residual value guarantees for the Lakeside Technology Center and a facility at our Aruba refinery (see Note 12);
- Preferred interests in our Trinity River and Clydesdale financing arrangements (see Note 13); and
- Equity investments in Chaparral and Gemstone and the related preferred interest in Gemstone (see Note 17).

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

The information contained in Item 2 updates, and you should read it in conjunction with, information disclosed in our 2002 Annual Report on Form 10-K and the financial statements and notes presented in Item 1, Financial Statements, of this Form 10-Q.

Overview

As was discussed more completely in our 2002 Form 10-K, in February 2003, we announced our 2003 Operational and Financial Plan to address liquidity needs in our business activities. The objectives of this plan were to:

- Preserve and enhance the value of our core businesses;
- Exit non-core businesses quickly, but prudently;
- Strengthen and simplify the balance sheet, while maximizing liquidity;
- Aggressively pursue additional cost reductions; and
- Continue to work diligently to resolve litigation and regulatory matters.

So far in 2003, we have accomplished a number of objectives under our plan. More specifically, we have:

- Completed or announced sales of assets for approximately $2.3 billion (see Note 3 for a further discussion of these divestitures);
- Completed financing transactions, consisting of loans and debt issuances totaling $1.9 billion;
- Repaid approximately $2.6 billion of maturing debt and other obligations, including long-term debt retirements of $294 million, the redemption of $980 million of obligations under our Trinity River financing arrangement, the redemption of $297 million of obligations under our Clydesdale financing arrangement, and the contribution of $1 billion to Limestone, which used the proceeds to repay $1 billion of Limestone's notes (see Item 1, Financial Statements, Notes 12, 13 and 17 for a further discussion of these actions);
- Entered into a new $3 billion revolving facility that matures in June 2005;
- Purchased the third party equity interest in our Gemstone power investment for $53 million;
- Restructured the obligations under our Clydesdale financing arrangement as a term loan that will amortize over the next two years; and
- Reached an agreement in principle (the Western Energy Settlement) in March 2003, which was designed to resolve our principal exposure relating to the western energy crisis while minimizing the impact on our current liquidity.

In April 2003, we announced the next steps under our plan. These actions include:

- Targeting additional pre-tax cost savings and business efficiencies of $250 million, beyond the previously announced savings of $150 million by the end of 2004;
- Working to recover cash collateral currently committed to our trading, petroleum, refining and other businesses; and
- Reducing our obligations senior to common stock by at least $2.5 billion in 2003.

To achieve our planned objectives, we expect to:

- Purchase the third party equity in our Chaparral investment for $175 million in the second quarter of 2003, resulting in the consolidation of the assets and liabilities of that entity; and

• Repay the $1.2 billion two-year term loan issued in February 2003 through the issuance of long-term debt in the capital markets in the second or third quarter of 2003 to eliminate the amortization requirements of that financing in 2004 and 2005.

Overview of Cash Flow Activities for the Quarter Ended March 31, 2003

For the quarters ended March 31, 2003 and 2002, our cash flows are summarized as follows:

	2003	2002
	(In millions)	
Cash flows from operating activities		
Net income (loss)	$(394)	$ 383
Non-cash income adjustments	979	356
Cash flows before working and non-working capital changes	585	739
Working capital changes	(670)	(533)
Non-working capital changes and other	(4)	(120)
Cash flows from operating activities	(89)	86
Cash flows from investing activities	(477)	(346)
Cash flows from financing activities	757	380
Change in cash	$ 191	$ 120

During the quarter ended March 31, 2003, our cash and cash equivalents increased by approximately $0.2 billion to approximately $1.8 billion. We generated cash from several sources, including cash flows from our principal operations, sales of assets and issuances of long-term debt. We used a major portion of that cash to fund our capital expenditures, including additional investments in unconsolidated subsidiaries, to purchase preferred shares of minority interest holders and to meet the increased demand for cash collateral as a result of market price changes and the downgrade in our credit rating early in the quarter. Overall, our cash sources and uses were summarized as follows (in billions):

Cash inflows	
Cash flows from operations (before working and non-working capital changes)	$0.6
Net proceeds from the sale of assets and investments	1.5
Net proceeds from the issuance of long-term debt	1.8
Net borrowings under revolving credit facility	0.5
Other	0.1
Total cash inflows	$4.5
Cash outflows	
Working capital and other demands	$0.7
Additions to property, plant and equipment	0.7
Investment in Limestone	1.0
Restricted cash demands	0.2
Dividends paid to common stockholders	0.1
Payments to redeem preferred interests of consolidated subsidiaries	1.2
Payments to retire long-term debt	0.3
Other	0.1
Total cash outflows	$4.3
Net change in cash	$0.2

A more detailed analysis of our cash flows from operating, investing and financing activities follows.

Cash From Operating Activities

We generated approximately $0.6 billion in cash from operations in 2003 before working and non-working capital changes, as compared to $0.7 billion in 2002. Net cash used in operating activities was $(0.1) billion for the quarter ended March 31, 2003, compared to net cash provided by operating activities of $0.1 billion for the same period in 2002. We used a significant amount of cash to meet working capital demands in both 2003 and 2002. The downgrade in our credit rating in late 2002 and early 2003 along with increases in natural gas prices at levels above hedged production prices resulted in margin calls of approximately $0.4 billion. Similarly, we used about $0.7 billion of cash for margin calls and option premiums in 2002. Additionally, our price risk management activities generated $0.4 billion less cash in 2003 compared to 2002 because of our decision in November 2002 to exit the energy trading business which resulted in a decrease in cash settlements.

Cash From Investing Activities

Net cash used in our investing activities was $0.5 billion for the quarter ended March 31, 2003. Our investing activities consisted primarily of capital expenditures and equity investments of $1.7 billion offset by net proceeds from sale of assets and investments of $1.5 billion. Our capital expenditures and equity investments included the following (in billions):

Production exploration, development and acquisition expenditures	$0.5
Pipeline expansion, maintenance and integrity projects	0.1
Investment in Limestone	1.0
Other (primarily petroleum and power projects)	0.1
Total capital expenditures and equity investments	$1.7

Cash received from our investing activities includes $1.5 billion from the sale of assets and investments. Our asset sales proceeds were primarily attributable to the sale of natural gas and oil properties located in western Canada, New Mexico, Oklahoma and the Gulf of Mexico for $0.7 billion, the sale of an equity investment in CE Generation for $0.2 billion, the sale of the Corpus Christi refinery, the Florida Petroleum terminals and the tug and barge operations for $0.4 billion, and the sale of other pipeline, power, petroleum and processing assets of $0.2 billion.

Cash From Financing Activities

Net cash provided by our financing activities was $0.8 billion for the quarter ended March 31, 2003. Cash provided from our financing activities included the net proceeds from the issuance of long-term debt of $1.8 billion and $0.5 billion of short-term borrowings under our revolving credit facility. Further, we received $0.1 billion from notes payable to affiliates. Cash used by our financing activities included payments made to retire third party long-term debt of $0.3 billion. We also paid $1.2 billion to fully redeem the Trinity River preferred securities and partially redeem Clydesdale preferred securities previously issued by our subsidiaries. Further, during the quarter ended March 31, 2003, we paid dividends of $0.1 billion to common stockholders.

Cash Flow Outlook

For the remainder of 2003, we expect to recover approximately $1.5 billion in working capital. The sources of our expected working capital include:

- Substitution of letters of credit for cash deposits;
- Sale of inventory associated with petroleum assets; and
- Recovery of posted margins through settlement of positions for trading as well as production hedges.

We also anticipate that we will sell additional assets during the remainder of 2003, which could generate up to approximately $1.5 billion in proceeds. Through a combination of working capital recoveries and asset sales, we anticipate we could reduce our long-term debt by as much as $3.0 billion.

Financing and Commitments

Our 2002 Form 10-K includes a detailed discussion of our liquidity, financing activities, contractual obligations and commercial commitments. The information presented below updates, and you should read it in conjunction with, the information disclosed in our 2002 Form 10-K.

Short-Term Debt and Credit Facilities

At March 31, 2003, our weighted average interest rate on our short-term credit facilities was 2.61%, and at December 31, 2002, it was 2.69%. We had the following short-term borrowings and other financing obligations:

	March 31, 2003	December 31, 2002
	(In millions)	
Current maturities of long-term debt and other financing obligations	$ 575	$ 575
Short-term credit facilities	2,000	1,500
	$2,575	$2,075

Long-Term Debt Obligations

During the first quarter of 2003, we completed several debt financing transactions related to our long-term debt obligation:

Date	Company	Type	Interest Rate	Principal	Net Proceeds[1]	Due Date
				(In millions)		
Issuances						
March	El Paso[2]	Two-year term loan	LIBOR+4.25%	$1,200	$1,149	2004-2005
March	SNG	Senior notes	8.875%	400	385	2010
March	ANR	Senior notes	8.875%	300	288	2010
				$1,900	$1,822	
Retirements						
January	Other	Long-term debt	Various	$ 54	$ 54	2003
February	El Paso CGP	Long-term debt	4.49%	240	240	2004
				$ 294	$ 294	

(1) Net proceeds were primarily used to repay maturing long-term debt, redeem preferred interests of consolidated subsidiaries, repay short-term borrowings and other financing obligations and for general corporate and investment purposes.

(2) We have collateralized this term loan with natural gas and oil reserves of approximately 2.3 trillion cubic feet of gas equivalents. The minimum LIBOR rate is 3.5%. This term loan has scheduled payments of $300 million in each of June 2004 and September 2004 and the $600 million balance in March 2005. Additionally, the loan facility requires us to pay a facility fee equal to 2% per annum on the average daily aggregate outstanding principal amount of the loan. Funds from the term loan were primarily used to retire the Trinity River financing arrangement.

Credit Facilities

In April 2003, we entered into a new $3 billion revolving credit facility, with a $1.5 billion letter of credit sublimit, which matures in June 2005. This facility replaces our previous $3 billion revolving credit facility. Our existing $1 billion revolving credit facility, which matures in August 2003, and approximately $1 billion of other financing arrangements (including leases, letters of credit and other facilities) were also amended to conform our obligations to the new $3 billion revolving credit facility. Our $3 billion revolving credit facility, $1 billion revolving credit facility, and the other financing arrangements are secured by our equity in EPNG, TGP, ANR, Wyoming Interstate Company, ANR Storage Company, and our common and Series C units in El Paso Energy Partners, L.P. These credit facilities and other financing arrangements are also collateralized by our equity in the companies that own the assets that collateralize our Clydesdale financing arrangement. For a discussion of Clydesdale, see Item 1, Financial Statements, Note 13.

EPNG and TGP remain jointly and severally liable for any amounts outstanding under the new $3 billion revolving credit facility through August 19, 2003. Also, EPNG and TGP remain jointly and severally liable under our $1 billion revolving credit facility and as such are liable for any amounts under the facility until its maturity in August 2003. In addition, El Paso CGP Company is no longer a borrower under the $1 billion credit facility.

The revolving credit facilities have a borrowing cost of LIBOR plus 350 basis points and letter of credit fees of 350 basis points. In addition, the covenant relating to subsidiary debt requirements was removed under the new and amended agreements. Also, EPNG, TGP, ANR, and upon the maturity of the Clydesdale financing transaction, CIG cannot incur incremental debt if the incurrence of the incremental debt would cause their debt to EBITDA ratio (as defined in the new revolving credit facility) for that particular company to exceed 5 to 1. As of the date of this filing, we were in compliance with these covenants. As of March 31, 2003, we had $1.5 billion outstanding under the $3 billion revolving credit facility and $500 million outstanding under the $1 billion revolving credit facility. We have also issued $456 million letters of credit under the $1 billion revolving credit facility.

The availability of borrowings under our credit and borrowing agreements is subject to specified conditions, which we currently meet. These conditions include compliance with the financial covenants and ratios required by those agreements, absence of default under the agreements, and continued accuracy of the representations and warranties contained in the agreements.

Notes Payable to Affiliates

Our notes payable to unconsolidated affiliates as of March 31, 2003, were $410 million versus $390 million as of December 31, 2002. The increase was primarily due to the issuance of a $75 million revolving note to a subsidiary of Diamond Power Ventures, LLC, which is owned by us and Gemstone with a variable interest rate based on 90-day LIBOR plus 0.50%. This increase was partially offset by the retirement of $45 million of Chaparral debt securities.

Minority and Preferred Interests of Consolidated Subsidiaries

The total amount outstanding for securities of subsidiaries and preferred stock of consolidated subsidiaries was $2.3 billion at March 31, 2003, versus $3.4 billion at December 31, 2002. The decrease was due to the retirements of $980 million of Trinity River preferred interests and $189 million of preferred member interests in Clydesdale in the first quarter of 2003. In April 2003, we restructured our Clydesdale financing arrangement as a term loan that will amortize over the next two years. See Item 1, Financial Statements, Note 13, for a further discussion of preferred interests of our consolidated subsidiaries.

Letters of Credit

We enter into letters of credit in the ordinary course of our operating activities. As of March 31, 2003, we had outstanding letters of credit of approximately $807 million and $852 million as of December 31, 2002. At March 31, 2003, $456 million of our outstanding letters of credit were issued on our revolving credit facility, and $183 million was supported with cash collateral.

Financial Position Impact of Consolidations

As a result of actions we have taken since the end of the first quarter of 2003, we will consolidate the following entities during the second quarter:

- Chaparral;
- Gemstone;
- The owner and lessor of the Lakeside Technology Center;

- The owner and lessor of a facility at our Aruba refinery; and
- The preferred member interest holder of Clydesdale.

These steps were all taken to simplify our financial structure and refinance existing arrangements, thereby enabling us to better manage our liquidity requirements. Had we consolidated these entities on March 31, 2003, our financial position, including the estimated impact of consolidating these entities would have been as follows:

	As of March 31, 2003
	(In billions)
Total assets	$47.6
Total liabilities (excluding debt)	14.4
Total debt	24.2
Total minority interest	1.2

The impact above is based on the carrying values of the entities we will consolidate. The actual impact will be based on the fair values of the individual assets and liabilities and economic considerations at the time they are consolidated. At this time, the allocation of those fair values is not complete and as a result, the estimated amounts presented above will change.

Segment Results

We use earnings before interest expense and income taxes (EBIT) to assess the operating results and effectiveness of our business segments. We define EBIT as operating income, adjusted for several items, including: equity earnings from unconsolidated affiliates, minority interests of consolidated, but less than wholly owned operating subsidiaries and other miscellaneous non-operating items. Items that are not included in this measure are financing costs, including interest and debt expense, return on preferred interests of consolidated subsidiaries, income taxes, discontinued operations and the impact of accounting changes. The following is a reconciliation of our operating income to our EBIT and our EBIT to our income (loss) from continuing operations for the quarters ended March 31:

	2003	2002
	(In millions)	
Operating revenues	$ 4,018	$ 3,765
Operating expenses	(3,957)	(2,753)
Operating income	61	1,012
Losses from unconsolidated affiliates	(99)	(223)
Minority interest in consolidated subsidiaries	1	(52)
Other income	39	42
Other expenses	(126)	(66)
EBIT	(124)	713
Interest and debt expense	(345)	(307)
Return on preferred interests of consolidated subsidiaries	(39)	(40)
Income taxes	133	(118)
Income (loss) from continuing operations	$ (375)	$ 248

We believe EBIT is a useful measurement for our investors because it allows them to evaluate the effectiveness of our businesses and operations and our investments from an operational perspective. This measurement may not be comparable to measurements used by other companies and should not be used as a substitute for net income or other performance measures such as operating income or operating cash flow.

Overview of Results of Operations

Below are our results of operations (as measured by EBIT) by segment for the quarters ended March 31. A reconciliation of operating income to EBIT is provided below for each segment. Our four operating segments — Pipelines, Production, Field Services and Merchant Energy — provide a variety of energy products and services. They are managed separately as each business unit requires different technology, operational and marketing strategies. These segment results include the impacts of asset impairments, gains and losses on long-lived assets and other charges, which are discussed further in Item 1, Financial Statements, Notes 2, 4, 5, 6, 7 and 17.

EBIT by Segment	2003	2002
	(In millions)	
Pipelines	$ 429	$399
Production	244	176
Field Services	27	51
Merchant Energy	(756)	93
Segment EBIT	(56)	719
Corporate and other	(68)	(6)
Consolidated EBIT	$(124)	$713

Pipelines

Our Pipelines segment holds our interstate transmission businesses. For a further discussion of the business activities of our Pipelines segment, see our 2002 Form 10-K. Results of our Pipelines segment operations were as follows for the quarters ended March 31:

Pipelines Segment Results	2003	2002
	(In millions, except volume amounts)	
Operating revenues	$ 754	$ 703
Operating expenses	(370)	(346)
Operating income	384	357
Other income	45	42
EBIT	$ 429	$ 399

	2003	2002
Throughput volumes (BBtu/d)[(1)]		
TGP	5,991	4,789
EPNG and MPC	4,069	4,203
ANR	5,461	5,044
CIG and WIC	2,933	2,851
SNG	2,451	2,371
Equity investments (our ownership share)	2,704	2,469
Total throughput	23,609	21,727

(1) Throughput volumes for 2002 exclude 224 BBtu/d related to the sale of our equity investment in the Alliance pipeline system which was completed in March 2003. Throughput volumes also exclude intersegment activities. Prior period volumes have been restated to reflect current year presentations which include billable transportation throughput volume for storage injection and withdrawal.

Operating revenues for the quarter ended March 31, 2003, were $51 million higher than the same period in 2002. This increase was due to the impact of higher prices in 2003 on natural gas recovered in excess of amounts used in operations of $33 million, an increase in transportation revenues of $17 million resulting from increased throughput volumes as a result of colder winter weather, higher sales under natural gas purchase contracts of $8 million and increased revenues of $8 million due to system expansion projects placed in service in the latter part of 2002. Also contributing to the increase were $4 million related to a rate settlement in 2003, storage gas sales of $3 million which commenced in the fourth quarter of 2002, an increase of $3 million in natural gas liquids revenues resulting from higher prices and a $3 million increase in reservation revenues due to an increase in contracted volumes on the WIC system. These increases were partially offset by a $20 million decrease in revenues due to CIG's sale of the Panhandle field and other production properties in July 2002, a decrease of $15 million due to capacity contracts that have expired which EPNG is prohibited from remarketing due to its September 20, 2002 FERC order (for further discussion of this order, see Item 1, Financial Statements, Note 14) and a $6 million fuel settlement resulting from our Mojave Pipeline rate case settled in the first quarter of 2002.

Operating expenses for the quarter ended March 31, 2003, were $24 million higher than the same period in 2002. The increase was due to an $11 million gain on the sale of pipeline expansion rights in February 2002, higher fuel and system supply purchases in 2003 of $11 million resulting from higher prices and volumes in 2003, lower benefit costs in 2002 of $6 million, $4 million of amortization expense related to EPNG's portion of the Western Energy Settlement and $2 million of higher depreciation related to transmission system expansion projects placed in service in 2002. These increases were partially offset by a $12 million decrease in operating expenses due to CIG's sale of Panhandle field and other production properties in July 2002 and a $9 million decrease due to bad debt expense recorded in 2002 related to the bankruptcy of Enron Corp.

Other income for the quarter ended March 31, 2003, was $3 million higher than the same period in 2002. The increase was primarily due to higher equity earnings from our investment in Citrus Corporation of $13 million. Offsetting this increase were lower equity earnings of $5 million from Alliance Pipeline due to the sale of our interests in fourth quarter of 2002 and a charge of $4 million related to the partial termination of a hedging obligation for Blue Lake Gas Storage Company, an investment in which we have a 75 percent ownership interest.

Production

Our Production segment conducts our natural gas and oil exploration and production activities. For a further discussion of the business activities of our Production segment, see our 2002 Form 10-K. Results of our Production segment operations were as follows for the quarters ended March 31:

Production Segment Results	2003	2002
	(In millions, except volumes and prices)	
Operating Revenues:		
Natural gas	$ 490	$ 480
Oil, condensate and liquids	106	82
Other	(1)	(12)
Total operating revenues	595	550
Transportation and net product costs	(31)	(22)
Total operating margin	564	528
Operating expenses[1]	(329)	(353)
Operating income	235	175
Other income	9	1
EBIT	$ 244	$ 176
Volumes and prices		
Natural gas		
Volumes (MMcf)	101,743	133,266
Average realized prices with hedges ($/Mcf)[2]	$ 4.82	$ 3.60
Average realized prices without hedges ($/Mcf)[2]	$ 6.68	$ 2.32
Average transportation costs ($/Mcf)	$ 0.22	$ 0.14
Oil, condensate and liquids		
Volumes (MBbls)	3,724	4,988
Average realized prices with hedges ($/Bbl)[2]	$ 28.31	$ 16.53
Average realized prices without hedges ($/Bbl)[2]	$ 29.10	$ 15.87
Average transportation costs ($/Bbl)	$ 0.98	$ 0.85

(1) Includes production costs, depletion, depreciation and amortization, ceiling test charges, asset impairments, gain and loss on long-lived assets, corporate overhead, general and administrative expenses and severance and other taxes.

(2) Prices are stated before transportation costs.

For the quarter ended March 31, 2003, operating revenues were $45 million higher than the same period in 2002. Our natural gas revenues, including the impact of hedges, were $10 million higher in the first quarter of 2003. Realized natural gas prices rose in 2003 by 34 percent, resulting in a $124 million increase in revenues, when compared to the same period in 2002. Our 2003 natural gas volumes decreased by 24 percent, resulting in a $114 million decrease in revenues, from the same period in 2002. These declines were due largely to the sale of properties in Colorado, Utah, Texas, and western Canada during 2002 as well as normal production declines. Our oil, condensate and liquids revenues, including the impact of hedges, were $24 million higher in the first quarter of 2003. Realized oil, condensate and liquids prices rose in 2003 by 71 percent, resulting in a $44 million increase in revenues, when compared to the same period in 2002. Our 2003 oil, condensate and liquids volumes decreased by 25 percent, resulting in a $20 million decrease in revenues, from the same period in 2002. These declines were again due largely to the sale of properties and normal declines mentioned above. Further increasing operating revenues was an additional loss of $13 million in 2002 resulting from a mark-to-market adjustment of derivative positions that no longer qualify as cash flow hedges. These hedges no longer qualify for hedge accounting treatment since they were designated as hedges of anticipated future production from natural gas and oil properties that were sold in March 2002.

Transportation and net product costs for the quarter ended March 31, 2003, were $9 million higher than the same period in 2002 primarily due to a higher percentage of natural gas volumes subject to transportation fees and higher costs incurred to meet minimum payment obligations under pipeline agreements.

Operating expenses for the quarter ended March 31, 2003, were $24 million lower than the same period in 2002 due to a non-cash full cost ceiling test charge of $33 million incurred in the first quarter of 2002 for our international properties in Brazil and Turkey. Depletion expense was lower by $2 million comprised of a $49 million decrease due to lower production volumes in 2003, partially offset by a $42 million increase resulting from higher depletion rates in 2003 and costs of $5 million related to retirement obligations from our adoption in 2003 of SFAS No. 143. The higher depletion rate resulted from higher capitalized costs in the full cost pool coupled with a lower reserve base. Also contributing to the decrease in 2003 operating expenses were decreased oilfield service costs of $14 million due primarily to asset dispositions which reduced labor and production processing fees. Partially offsetting the decrease in expenses were asset impairments of $9 million related to non-full cost assets in Canada, higher corporate overhead allocations of $5 million and employee severance costs of $3 million in 2003. In addition, the decrease in expenses was offset by $6 million of higher severance and other taxes in 2003 and a $2 million gain on non-full cost pool assets recognized in 2002. The severance taxes increase was due to higher commodity prices in 2003 and tax credits taken in 2002 for qualified natural gas wells.

Other income for the quarter ended March 31, 2003, was $8 million higher than the same period in 2002 primarily due to higher earnings in 2003 from Pescada, an equity investment in Brazil.

Field Services

Our Field Services segment conducts our midstream activities. A subsidiary in our Field Services segment serves as the general partner of El Paso Energy Partners, L.P. and owns a one percent general partner interest. On May 1, 2003, El Paso Energy Partners announced that it will begin doing business effective May 15, 2003, as GulfTerra Energy Partners, L.P. In April 2003, we announced we may sell between five and ten percent of our one percent general partner interest. In addition to our general partner interest, we currently own through various subsidiaries 24.6 percent of the partnership's common units, all of the Series B preference units and all of the Series C units. We recognize earnings and receive cash from the partnership in several ways, including through a share of the partnership's cash distributions and through our ownership of limited, preferred and general partner interests. We are also reimbursed for costs we incur to provide various operational and administrative services to the partnership. In addition, we are reimbursed for other costs paid directly by us on the partnership's behalf. During the first quarter of 2003, we were reimbursed approximately $24 million for expenses incurred on behalf of the partnership. At March 31, 2003, our common units had a market value of $362 million, our preference units had a liquidation value of $161 million, and our Series C units had a value of $347 million. During the first quarter of 2003, our earnings and cash from El Paso Energy Partners were as follows:

	Earnings Recognized	Cash Received
	(In millions)	
General partner's share of distributions	$15	$15
Proportionate share of income available to common unit holders	5	8
Series B preference units	4	—[1]
Series C units	5	7
	$29	$30

[1] The partnership is not obligated to pay distributions on these units until 2010.

For a further discussion of the business activities of our Field Services segment, see our 2002 Form 10-K. In March 2003, we received approval from our Board of Directors to sell our assets in the Mid-Continent and north Louisiana regions. Our Mid-Continent assets primarily include our Greenwood, Hugoton, Keyes and Mocane natural gas gathering systems, our Sturgis, Mocane and Lakin processing plants and our processing arrangements at three additional processing plants. Our north Louisiana assets primarily include our Dubach processing plant and Gulf States interstate natural gas transmission system. We expect to complete the sales of these assets by the end of the second quarter of 2003. These assets generated EBIT of approximately $10 million during the year ended December 31, 2002. Once this sale is completed, our remaining assets will consist primarily of our investment in El Paso Energy Partners and processing facilities in the south Texas, south Louisiana and Rocky Mountain regions.

As a result of our asset sales and the resulting decline in our gathering and treating activities, we expect our future EBIT to decrease considerably. However, we expect the increase in earnings from our interests in El Paso Energy Partners to partially offset the anticipated decrease in EBIT primarily because some of the assets we sold were to the partnership. For a further discussion of the business activities of our Field Services segment, see our 2002 Form 10-K. Results of our Field Services segment operations were as follows for the quarters ended March 31:

Field Services Segment Results	2003	2002
	(In millions, except volumes and prices)	
Gathering, transportation and processing gross margins[1]	$ 47	$ 125
Operating expenses	(47)	(87)
Operating income	—	38
Other income	27	13
EBIT	$ 27	$ 51
Volumes and prices		
Gathering and transportation		
Volumes (BBtu/d)	577	5,832
Prices ($/MMBtu)	$ 0.22	$ 0.16
Processing		
Volumes (inlet BBtu/d)	3,307	4,117
Prices ($/MMBtu)	$ 0.11	$ 0.10

(1) Gross margins consist of operating revenues less cost of products sold. We believe this measurement is more meaningful to analyzing our Field Services operating results because commodity costs play such a significant role in the determination of profit from our midstream activities.

Total gross margins for the quarter ended March 31, 2003, were $78 million lower than the same period in 2002, primarily a result of asset sales. The table below presents the gross margins earned by these assets in the first quarter of 2002 (in millions):

Texas and New Mexico midstream assets (sold in April 2002)[1]	$38
San Juan Basin gathering, treating and processing assets (sold in November 2002)[1]	29
Dragon Trail processing plant (sold in May 2002)	3
Wyoming gathering assets (sold in January 2003)	2
Natural Buttes and Ouray gathering systems (sold in December 2002)	1
Total	$73

(1) Sold to El Paso Energy Partners.

Gross margins also decreased due to the favorable resolution of fuel, rate and volume matters of $13 million in the first quarter of 2002. Partially offsetting these decreases was an $8 million increase due to higher natural gas prices and natural gas liquids prices in 2003, which favorably impacted our processing margins.

Operating expenses for the quarter ended March 31, 2003, were $40 million lower than the same period in 2002. The decrease was primarily due to the sales of assets discussed above, resulting in lower operating costs of $21 million and lower depreciation expense of $9 million. Also contributing to this decrease were higher reimbursements of $6 million from El Paso Energy Partners to provide administrative and other activities to operate their assets. The increase in reimbursements is a direct result of our operation of the additional assets that El Paso Energy Partners currently owns. In addition, our 2002 cost reduction plan, initiated mid-2002, resulted in $3 million of lower operating costs.

Other income for the quarter ended March 31, 2003, was $14 million higher than the same period in 2002 due to increased earnings from our investment in El Paso Energy Partners. In November 2002, we received 10,937,500 Series C units issued by El Paso Energy Partners as part of the proceeds from the sale of San Juan Basin assets to the partnership, and these units are allocated earnings on an equal basis with the common units.

Merchant Energy

Our Merchant Energy segment consists of three divisions: global power, petroleum and energy trading. Below are Merchant Energy's operating results and an analysis of those results for the quarters ended March 31:

	Division				Total Merchant Energy Segment
Merchant Energy Segment Results	**Global Power**	**Petroleum**	**Energy Trading**	**Eliminations**	
			(In millions)		
2003					
Gross margin	$ 98	$ 246	$(141)	$ (3)	$ 200
Operating expenses	(97)	(569)	(51)	3	(714)
Operating income (loss)	1	(323)	(192)	—	(514)
Other income (expense)	(247)	(1)	6	—	(242)
EBIT	$(246)	$(324)	$(186)	$ —	$(756)
2002					
Gross margin	$ 595	$ 171	$ 68	$(15)	$ 819
Operating expenses	(156)	(180)	(43)	15	(364)
Operating income (loss)	439	(9)	25	—	455
Other income (expense)	(478)	96	20	—	(362)
EBIT	$ (39)	$ 87	$ 45	$ —	$ 93

Global Power

Our global power division includes the ownership and operation of domestic and international power generating facilities. We announced in April 2003 our intent to pursue a sale of additional domestic power generation facilities. In this regard, we have commenced a process to sell most of our domestic power generation facilities. For a further discussion of our global power division, see our 2002 Form 10-K. For a discussion of our Chaparral and Gemstone investments, see Item 1, Financial Statements, Note 17. Results of our global power division operations were as follows for the quarters ended March 31:

Global Power Division Results	**2003**	**2002**
	(In millions)	
Gross margin	$ 98	$ 595
Operating expenses	(97)	(156)
Operating income	1	439
Other expense	(247)	(478)
EBIT	$(246)	$ (39)

Gross margin consists of revenues from our power plants and the net results from our power restructuring activities. The cost of fuel used in the power generation process is included in operating expenses. For the quarter ended March 31, 2003, our gross margin was $497 million lower than the same period in 2002. The decrease was due primarily to power contract restructurings for our Eagle Point Cogeneration and Mount Carmel power plants that we completed in the first quarter of 2002, which contributed $434 million to our gross margin in 2002, including an $80 million loss on a power supply agreement that we entered into with our energy trading division in the first quarter of 2002 associated with the Eagle Point Cogeneration restructuring transaction. The effects of this power supply agreement were eliminated from Merchant Energy's consolidated results. Contributing to the decrease in gross margin was a decrease of $33 million in 2003 power generation revenues primarily due to the shutdown of our Eagle Point Cogeneration facility for maintenance in the first quarter of 2003. Also contributing to the decrease was a $46 million management fee we received from Chaparral in the first quarter of 2002. As a result of our planned acquisition of the third party equity and resulting consolidation of Chaparral in 2003, we will not receive management fees from Chaparral in 2003.

Operating expenses for the quarter ended March 31, 2003, were $59 million lower than the same period in 2002. The decrease was due primarily to $19 million in turbine forfeiture fees we paid in 2002 as plans for future construction of new power plants were reduced in 2002 and a decrease of $13 million in payroll, development and overhead costs resulting primarily from the sale of power plants in 2002. Also contributing to this decrease was a $6 million decrease in operating costs related to the shutdown of our Eagle Point Cogeneration facility for maintenance in 2003 and a $6 million decrease in depreciation expense in 2003 primarily due to lower depreciation on our Eagle Point Cogeneration facility.

Other expense for the quarter ended March 31, 2003, was $231 million lower than the same period in 2002. This decrease was primarily due to impairment charges on our Agua del Cajon, CAPSA/CAPEX and Costañera investments in Argentina of $342 million in 2002. Also contributing to this decrease was a $90 million contract termination fee we paid to our petroleum division associated with the termination of a steam contract between our Eagle Point Cogeneration facility and the Eagle Point refinery in 2002 that was eliminated from Merchant Energy's consolidated results. Further contributing to this decrease was an increase in equity earnings of $12 million from Gemstone and $10 million from Chaparral in 2003 and $52 million of minority interest expense recorded primarily on our power contract restructurings during the first quarter of 2002. Partially offsetting this decrease was a $207 million impairment we recorded on our equity investment in Chaparral in the first quarter of 2003. Also partially offsetting this decrease was a $86 million loss we recorded in the first quarter of 2003 on the impairment of notes from our Milford equity investment and loss accruals related to other associated contracts. These amounts are based on the ongoing settlement negotiations related to this investment.

Petroleum

We announced in 2003 our intent to reduce our involvement in the LNG business and exit substantially all of our petroleum businesses. We also recently announced our intent to pursue the sale of our Aruba refinery, in which we have a net investment of approximately $1.2 billion, excluding an operating lease for a support facility that will be consolidated in the second quarter of 2003. It is likely that if we pursue a sale of Aruba in the near term, we will not recover our full investment and could recognize an impairment or loss on the sale. For a further discussion of our petroleum division, see our 2002 Form 10-K. Results of our petroleum division operations were as follows for the quarters ended March 31:

Petroleum Division Results	2003	2002
	(In millions)	
Gross margin	$ 246	$ 171
Operating expenses	(569)	(180)
Operating loss	(323)	(9)
Other income (expense)	(1)	96
EBIT	$(324)	$ 87

Gross margin consists of revenues from our refineries and commodity trading activities, less costs of the feedstocks used in the refining process and the costs of commodities sold. For the quarter ended March 31, 2003, our gross margin was $75 million higher than the same period in 2002. This increase included higher refining margins of $37 million at our Aruba refinery due to higher spreads between the sales prices of refined products and underlying feedstock costs and $48 million at our Eagle Point refinery due to increased processing volumes and higher spreads between the sales prices of refined products and underlying feedstock costs. Also contributing to this increase was a $7 million increase in the fair value of our LNG supply contract derivatives compared to a $26 million decrease in the fair value of those contracts in 2002. These increases were partially offset by lower petroleum trading margins of $41 million on domestic crude and products resulting from the decision to exit our petroleum-related trading operations during 2003.

Operating expenses for the quarter ended March 31, 2003, were $389 million higher than the same period in 2002. The increase was primarily due to a $350 million impairment of our Eagle Point refinery and our chemical assets in the first quarter of 2003 resulting from our announced expectation that we will dispose of these assets. Also contributing to this increase were $53 million of costs incurred in 2003 associated with the reduction of our involvement in the LNG business. Also contributing to this increase was a $28 million increase in non-routine maintenance and other operating costs, primarily at our Aruba facility, and $11 million of employee severance costs incurred in 2003. Partially offsetting this increase was $56 million of net gains primarily from the sale of our Corpus Christi refinery and Florida petroleum terminals and tug and barge operations completed in 2003.

Other income for the quarter ended March 31, 2003, was $97 million lower than the same period in 2002. This decrease was primarily due to a $90 million contract termination fee we received from our global power division associated with the restructuring of a steam contract between our Eagle Point refinery and the Eagle Point Cogeneration facility in 2002, which was eliminated from Merchant Energy's consolidated results.

Energy Trading

In November 2002, we announced that we would exit the energy trading business due to the increasing and volatile cash demands inherent in that business, which were magnified by our credit downgrade. In late 2002, we began actively liquidating our trading portfolio and anticipate that this effort will continue through 2004. During the first quarter of 2003, we liquidated approximately 13,000, or 33 percent of the total number of forward positions outstanding at December 31, 2002. We have also liquidated 96 Bcf of the 125 Bcf of natural gas storage rights and 2.2 Bcf/day of our 4.4 Bcf/day of transportation capacity that we owned in 2002. We also have completed the liquidation of our European portfolio.

For a further discussion of our energy trading division, see our 2002 Form 10-K. Results of our energy trading division operations were as follows for the quarters ended March 31:

Energy Trading Division Results	**2003**	**2002**
	(In millions)	
Gross margin	$(141)	$ 68
Operating expenses	(51)	(43)
Operating income (loss)	(192)	25
Other income	6	20
EBIT	$(186)	$ 45

Gross margin consists of revenues from commodity trading and origination activities less the costs of commodities sold, including changes in the fair value of our energy trading portfolio. For the quarter ended March 31, 2003, gross margin was $209 million lower than the same period in 2002. This decrease was due primarily to $107 million of losses we incurred in the first quarter of 2003 related to continued demand charges and hedges on our natural gas transportation and storage capacity contracts and trading losses on our forward trading portfolio. During the first quarter of 2003, we focused on managing our energy trading portfolio to lessen our exposure to cash collateral requirements. As a consequence, we did not fully use contracted capacity on these transportation and storage contracts. We also recorded $34 million of losses in 2003 associated with the early termination of transactions related to our efforts to liquidate our energy trading portfolio. Also contributing to this decrease was an $80 million gain during 2002 on a power supply agreement that we entered into with our global power division in the first quarter of 2002 associated with the Eagle Point Cogeneration restructuring, which was eliminated from Merchant Energy's consolidated results.

Operating expenses for the quarter ended March 31, 2003, were $8 million higher than the same period in 2002 primarily due to $12 million of amortization expense we recorded in the first quarter of 2003 associated with our Western Energy Settlement.

Other income for the quarter ended March 31, 2003, was $14 million lower than the same period in 2002. This decrease was primarily due to lower interest income in 2003 resulting from lower average interest bearing balances in 2003.

Fair Value of Price Risk Management Contracts as of March 31, 2003

The following table details the net estimated fair value of our derivative energy contracts (both trading and non-trading) by year of maturity and valuation methodology as of March 31, 2003. We classify as trading activities those derivative price risk management activities that we enter into with the objective of generating profits or benefiting from exposure to shifts or changes in market prices. We classify all other derivative-related activities, including those related to power restructuring and hedging activities, as non-trading price risk management activities.

Source of Fair Value	Maturity Less Than 1 Year	Maturity 1 to 3 Years	Maturity 4 to 5 Years	Maturity 6 to 10 Years	Maturity Beyond 10 Years	Total Fair Value
			(In millions)			
Trading contracts						
Exchange-traded positions[1]	$ (87)	$(39)	$ 18	$ 5	$ —	$(103)
Non-exchange traded positions[2]	6	49	(32)	(66)	—	(43)
Total trading contracts, net	(81)	10	(14)	(61)	—	(146)
Non-trading contracts[3]						
Non-exchange traded positions[2]	(232)	(59)	126	330	183	348
Total energy contracts	$(313)	$(49)	$112	$269	$183	$ 202

(1) Exchange-traded positions include positions that are traded on active exchanges such as the New York Mercantile Exchange, International Petroleum Exchange and London Clearinghouse.

(2) Non-exchange traded positions include those positions that are valued based on exchange prices, third party pricing data and valuation techniques that incorporate specific contractual terms, statistical and simulation analysis and present value concepts.

(3) Non-trading energy contracts include derivatives from our power contract restructuring activities of $967 million and derivatives related to our natural gas and oil producing activities of $(619) million. Earnings related to the natural gas and oil producing derivative activities are included in our Production segment results.

The income impacts of both our trading and non-trading price risk management activities are included in all of the divisions of our Merchant Energy segment and in our Production segment. A reconciliation of these trading and non-trading activities for the quarter ended March 31, 2003, is as follows:

	Trading	Non-Trading	Total Commodity Based
		(In millions)	
Fair value of contracts outstanding at December 31, 2002	$ (59)	$ 459	$ 400
Fair value of contract settlements during the period	83	145	228
Change in fair value of contracts	(96)	(256)	(352)
Option premiums received, net	(74)	—	(74)
Net change in contracts outstanding during the period	(87)	(111)	(198)
Fair value of contracts outstanding at March 31, 2003	$(146)	$ 348	$ 202

Our trading portfolio is reflected at its estimated fair value, which is the amount at which the contracts in our portfolio could be bought or sold in a current transaction between willing buyers and sellers. However, the value we ultimately receive in settlement of our trading activities may be less than our estimates. As discussed above, we are actively liquidating our trading portfolio, which includes approximately 27,000 positions as of March 31, 2003. We believe the net realizable value of our trading portfolio, if liquidated in the timeframe set out in our exit plan, may be less than its currently estimated fair value. Our belief is based on recent transactions completed at values below estimated fair value and bids received on positions that were also below their fair value. Additionally, a portion of the transactions that we plan to liquidate are accounted for under the accrual method and are not recorded on our balance sheet.

Corporate and Other

Corporate and other net expenses, which include general and administrative activities as well as the operations of our telecommunications and other miscellaneous businesses, for the quarter ended March 31, 2003, were $62 million higher than the same period in 2002. The increase was due to a $33 million foreign currency loss resulting from the impact of foreign currency fluctuations on our Euro-denominated debt in 2003 and employee severance costs of $13 million in 2003. Also contributing to the increase were losses on the Lakeside Technology Center facility in our telecommunications business, including an $8 million contingent loss in the first quarter of 2003 and a $3 million decrease in rental revenue due to the loss of a significant tenant at the facility in 2002. Recently we announced our intent to sell or otherwise divest of our telecommunications business in which we have a $375 million investment, excluding the Lakeside Technology Center. It is likely that if we pursue a sale or other arrangement to divest of this business in the near term, we will not recover our full investment and we could incur an impairment or loss on the sale. For a further discussion of our telecommunications business, see our 2002 Form 10-K. An $8 million loss on the sale of aircraft in the first quarter of 2003 also contributed to the increase.

Interest and Debt Expense

Interest and debt expense for the quarter ended March 31, 2003, was $345 million, or $38 million higher than the same period in 2002. Below is an analysis of our interest expense for the quarters ended March 31:

	2003	2002
	(In millions)	
Long-term debt, including current maturities	$317	$264
Short-term debt	20	12
Other interest	14	40
Capitalized interest	(6)	(9)
Total interest expense	$345	$307

Interest expense on long-term debt for the quarter ended March 31, 2003, was $53 million higher than the same period in 2002 due to higher average debt balances. During 2003, we issued long-term debt of approximately $1.9 billion, with an average interest rate of 11.1%, including the issuance of the $1.2 billion two-year term loan in March 2003. These issuances increased interest on long-term debt by approximately $13 million. Also contributing to the increase was $59 million of interest related to various debt issuances during 2002 that were outstanding during the first quarter of 2003. Partially offsetting these increases were our retirements of approximately $1.5 billion of long-term debt during 2002 with an average interest rate of 6.8%, resulting in lower interest expense of approximately $20 million.

Interest expense on short-term debt for the quarter ended March 31, 2003, was $8 million higher than the same period in 2002. The increase was due to our borrowings under the revolving credit facilities in December 2002 and in February 2003. At March 31, 2003, our average revolving credit balance, which was based on daily ending balances, was approximately $1.8 billion, with an average interest rate of 2.7%. This increase was partially offset by the discontinuation of commercial paper activities in 2003.

Other interest for the quarter ended March 31, 2003, was $26 million lower than the same period in 2002. The decrease was due to the following: $14 million related to a decrease in balances for various notes; $11 million resulting from retirements of our other financing obligations; and an $8 million decrease due to the reduction in trading activities and the elimination of the receivables factoring program in the fourth quarter of 2002. These decreases were partially offset by a $7 million increase as a result of write-off of unamortized issue costs due to the retirement of the Trinity River financing arrangement in 2003.

Capitalized interest for the quarter ended March 31, 2003, was $3 million lower than the same period in 2002 primarily due to the lower interest rates in the first quarter of 2003 than the same period in 2002.

Income Taxes

Income tax benefit for the quarter ended March 31, 2003, was $133 million resulting in an effective tax rate of 26 percent. Income tax expense for the quarter ended March 31, 2002, was $118 million resulting in effective tax rate of 32 percent. Our effective tax rates were different than the statutory rate of 35 percent primarily due to the following:

- state income taxes;
- earnings from unconsolidated affiliates where we anticipate receiving dividends; and
- foreign income taxed at different rates.

Commitments and Contingencies

See Item 1, Financial Statements, Note 14, which is incorporated herein by reference.

New Accounting Pronouncements Issued But Not Yet Adopted

See Item 1, Financial Statements, Note 18, which is incorporated herein by reference.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

We have made statements in this document that constitute forward-looking statements, as that term is defined in the Private Securities Litigation Reform Act of 1995. Forward-looking statements include information concerning possible or assumed future results of operations. The words "believe," "expect," "estimate," "anticipate" and similar expressions will generally identify forward-looking statements. These statements may relate to information or assumptions about:

- earnings per share;
- capital and other expenditures;
- dividends;
- financing plans;
- capital structure;
- liquidity and cash flow;
- credit ratings;
- pending legal proceedings, claims and governmental proceedings, including environmental matters;
- future economic performance;
- operating income;
- management's plans; and
- goals and objectives for future operations.

Forward-looking statements are subject to risks and uncertainties. While we believe the assumptions or bases underlying the forward-looking statements are reasonable and are made in good faith, we caution that assumed facts or bases almost always vary from the actual results, and these variances can be material, depending upon the circumstances. We cannot assure you that the statements of expectation or belief contained in the forward-looking statements will result or be achieved or accomplished. Important factors that could cause actual results to differ materially from estimates or projections contained in forward-looking statements are described in our 2002 Form 10-K.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

There are no material changes in our quantitative and qualitative disclosures about market risks from those reported in our 2002 Form 10-K, except as presented below:

Commodity Price Risk

We measure risks on our portfolio of commodity and energy-related contracts on a daily basis using a Value-at-Risk model. We no longer separately manage and evaluate the Value-at-Risk associated with our trading and non-trading commodity and energy-related contracts. We measure our portfolio's Value-at-Risk using the historical simulation technique and we prepare it based on a confidence level of 95 percent and a one-day holding period. Our portfolio's Value-at-Risk was $15 million and $11 million as of March 31, 2003 and December 31, 2002, and represents our potential one-day unfavorable impact on the fair values of our commodity and energy-related contracts. The $4 million increase in our portfolio Value-at-Risk was related to higher natural gas price volatility and our efforts in the first quarter of 2003 to mitigate the cash flow impact of rising gas prices on our trading portfolio. As we liquidate our trading portfolio, our Value-at-Risk may vary more than in historical periods when we more actively managed our positions using Value-at-Risk. As a result, our Value-at-Risk could increase as we continue to exit this business.

Item 4. Controls and Procedures

Evaluation of Controls and Procedures. Under the supervision and with the participation of management, including our principal executive officer and principal financial officer, we have evaluated the effectiveness of the design and operation of our disclosure controls and procedures (Disclosure Controls) and internal controls (Internal Controls) within 90 days of the filing date of this Quarterly Report pursuant to Rules 13a-15 and 15d-15 under the Securities Exchange Act of 1934 (Exchange Act).

Definition of Disclosure Controls and Internal Controls. Disclosure Controls are our controls and other procedures that are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified under the Exchange Act. Disclosure Controls include, without limitation, controls and procedures designed to ensure that information required to be disclosed by us in the reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding required disclosure. Internal Controls are procedures which are designed with the objective of providing reasonable assurance that (1) our transactions are properly authorized; (2) our assets are safeguarded against unauthorized or improper use; and (3) our transactions are properly recorded and reported, all to permit the preparation of our financial statements in conformity with generally accepted accounting principles.

Limitations on the Effectiveness of Controls. El Paso's management, including the principal executive officer and principal financial officer, does not expect that our Disclosure Controls and Internal Controls will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple errors or mistakes. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the controls. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions; over time, control may become inadequate because of changes in conditions, or the degree of compliance with the policies or procedures may deteriorate. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected.

No Significant Changes in Internal Controls. We have sought to determine whether there were any "significant deficiencies" or "material weaknesses" in El Paso's Internal Controls, or whether the company had identified any acts of fraud involving personnel who have a significant role in El Paso's Internal Controls. This information was important both for the controls evaluation generally and because the principal executive officer and principal financial officer are required to disclose that information to our Board's Audit Committee and our independent auditors and to report on related matters in this section of the Quarterly Report. The principal executive officer and principal financial officer note that, from the date of the controls evaluation to the date of this Quarterly Report, there have been no significant changes in Internal Controls or in other factors that could significantly affect Internal Controls, including any corrective actions with regard to significant deficiencies and material weaknesses.

Effectiveness of Disclosure Controls. Based on the controls evaluation, our principal executive officer and principal financial officer have concluded that, subject to the limitations discussed above, the Disclosure Controls are effective to ensure that material information relating to El Paso and its consolidated subsidiaries is made known to management, including the principal executive officer and principal financial officer, particularly during the period when our periodic reports are being prepared.

Officer Certifications. The certifications from the principal executive officer and principal financial officer required under Sections 302 and 906 of the Sarbanes-Oxley Act of 2002 have been included herein, or as Exhibits to this Quarterly Report, as appropriate.

PART II — OTHER INFORMATION

Item 1. Legal Proceedings

See Part I, Item 1, Financial Statements, Note 14, which is incorporated herein by reference.

Item 2. Changes in Securities and Use of Proceeds

None

Item 3. Defaults Upon Senior Securities

None.

Item 4. Submission of Matters to a Vote of Security Holders

None.

Item 5. Other Information

None.

Item 6. Exhibits and Reports on Form 8-K

a. Exhibits

Each exhibit identified below is filed as a part of this report. Exhibits not incorporated by reference to a prior filing are designated by an "*"; all exhibits not so designated are incorporated herein by reference to a prior filing as indicated. Exhibits designated with a "+" represent management contracts or compensatory plans or arrangements.

Exhibit Number	Description
10.A	$3,000,000,000 Revolving Credit Agreement dated as of April 16, 2003 among El Paso Corporation, El Paso Natural Gas Company, Tennessee Gas Pipeline Company and ANR Pipeline Company, as Borrowers, the Lenders Party Thereto, and JPMorgan Chase Bank, as Administrative Agent, ABN Amro Bank N.V. and Citicorp North America, Inc., as Co-Document Agents, Bank of America, N.A. and Credit Suisse First Boston, as Co-Syndication Agents, J.P. Morgan Securities Inc. and Citigroup Global Markets Inc., as Joint Bookrunners and Co-Lead Arrangers. (Exhibit 99.1 to our Form 8-K filed April 18, 2003, Commission File No. 1-14365).
10.B	$1,000,000,000 Amended and Restated 3-Year Revolving Credit Agreement dated as of April 16, 2003 among El Paso Corporation, El Paso Natural Gas Company and Tennessee Gas Pipeline Company, as Borrowers, The Lenders Party Thereto, and JPMorgan Chase Bank, as Administrative Agent, ABN AMRO Bank N.V. and Citicorp North America, Inc., as Co-Document Agents, Bank of America, N.A., as Syndication Agent, J.P. Morgan Securities Inc. and Citigroup Global Markets Inc., as Joint Bookrunners and Co-Lead Arrangers. (Exhibit 99.2 to our Form 8-K filed April 18, 2003, Commission File No. 1-14365).

Exhibit Number	Description
10.C	Security and Intercreditor Agreement dated as of April 16, 2003 Among El Paso Corporation, the Persons Referred to therein as Pipeline Company Borrowers, the Persons Referred to therein as Grantors, Each of the Representative Agents, JPMorgan Chase Bank, as Credit Agreement Administrative Agent and JPMorgan Chase Bank, as Collateral Agent, Intercreditor Agent, and Depository Bank. (Exhibit 99.3 to our Form 8-K filed April 18, 2003, Commission File No. 1-14365).
*+10.X	Form of Agreement to Restate Balance of certain compensation under the Alternative Benefits Program (previously filed as the Estate Enhancement Program) dated December 31, 2001 by and between El Paso and the named executives on the exhibit thereto, and Form of Promissory Note dated December 31, 2002, in favor of El Paso by trusts established by named executives, loan amounts, and interest rates.
*+10.Y	Interim CEO Employment Agreement between Ronald L. Keuhn, Jr. and El Paso Corporation dated March 12, 2003.
*+10.Z	Severance Pay Plan Amended and Restated effective as of October 1, 2002; Supplement No. 1 to the Severance Pay Plan effective as of January 1, 2003; and Amendment No. 1 to Supplement No. 1 effective as of March 21, 2003.
*+10.AA	El Paso Production Companies Long Term Incentive Plan effective as of January 1, 2003.
*10.DD.1	Amendment No. 2 dated April 30, 2003 to the $1,200,000,000 Senior Secured Interim Term Credit and Security Agreement dated as of March 13, 2003.
*10.GG	Amended and Restated Sponsor Subsidiary Credit Agreement dated April 16, 2003 among Noric Holdings, L.L.C. as borrower, and The other Sponsor Subsidiaries Party as co-obligators, Mustang Investors, L.L.C., as Sponsor Subsidiary Lender, and Clydesdale Associates, L.P. as Subordinated Note Holder, and Wilmington Trust Company, as Sponsor Subsidiary Collateral Agent, and Citicorp North America, Inc. as Mustang Collateral Agent; Fifth Amended and Restated El Paso Agreement dated April 16, 2003 by El Paso Corporation, in favor of Mustang Investors, L.L.C. and the other Indemnified Persons; Amended and Restated Guaranty Agreement dated as of April 16, 2003 made by El Paso Corporation, as Guarantor in favor of Each Sponsor Subsidiary, Noric, L.L.C., Noric, L.P. and each Controlled Business as Beneficiaries; Definitions Agreement dated as of April 16, 2003 among El Paso Corporation and Noric Holdings, L.L.C. and the Other Sponsor Subsidiaries Party thereto, Mustang Investors, L.L.C., and Clydesdale Associates, L.P. and The other Parties Named therein.
*99.A	Certification of Chief Executive Officer Pursuant to 18 U.S.C. § 1350 as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002.
*99.B	Certification of Chief Financial Officer Pursuant to 18 U.S.C. § 1350 as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002.

Undertaking

We hereby undertake, pursuant to Regulation S-K, Item 601(b), paragraph (4)(iii), to furnish to the U.S. Securities and Exchange Commission, upon request, all constituent instruments defining the rights of holders of our long-term debt not filed herewith for the reason that the total amount of securities authorized under any of such instruments does not exceed 10 percent of our total consolidated assets.

b. Reports on Form 8-K

Date	Event Reported
January 8, 2003	Filed our Computation of Ratio of Earnings to Fixed Charges for five years ended December 31, 2001 and the nine months ended September 30, 2002.
January 9, 2003	Updated information for our sale of the San Juan midstream assets to El Paso Energy Partners.
February 5, 2003	Announced our 2003 Operational and Financial Plan.
February 10, 2003	Provided additional information on our 2003 Operational and Financial Plan.
February 11, 2003	Announced our CEO Transition Plan.
February 12, 2003	Responded to Moody's Investors Service downgrade.
February 13, 2003	Prepared comments on liquidity by our Chief Executive Officer at the UBS Warburg Energy Conference.
February 18, 2003	Requested that our shareholders reject Selim Zilkha's proposal to be brought before the 2003 Annual Meeting.
February 25, 2003	Announced continued progress on the execution of our 2003 Operation and Financial Plan.
March 3, 2003	Information concerning the private offerings of ANR Pipeline Company and Southern Natural Gas Company.
March 13, 2003	Announced that Ronald L. Kuehn, Jr. will become Chief Executive Officer and Chairman of the El Paso Board of Directors effective March 13, 2003.
March 13, 2003	Announced that John L. Whitmire will join the El Paso Board of Directors effective March 17, 2003.
March 18, 2003	Announced the retirement of $1 billion of notes associated with the Limestone Trust financing.
March 21, 2003	Announced that an Agreement in Principle had been reached with respect to the Western energy crisis.
March 28, 2003	Announced that J. Michael Talbert will join the El Paso Board of Directors effective April 1, 2003, and that John Bissell has been named Lead Director.
March 31, 2003	Announced earnings results for 2003.
April 7, 2003	Announced that James L. Dunlap joined the El Paso Board effective as of April 7, 2003.
April 16, 2003	Announced the completion of an important step in El Paso's plan to enhance liquidity and financial flexibility; the extension of maturity of El Paso's $3 billion revolving credit facility.
April 16, 2003	Announced the sale of East Coast Power, L.L.C. interests for $456 million.
April 18, 2003	Announced completion of an important objective of El Paso's 2003 operational and financial plan by refinancing major bank facility.
April 23, 2003	Filed our Computation of Ratio of Earnings to Fixed Charges for five years ended December 31, 2002.
April 23, 2003	Presented slides on the progress of our Operational and Financial Plan at investor meetings.
April 24, 2003	Announced additional possible asset sales.

Date	Event Reported
April 24, 2003	Announced sale of Mid-Continent and northern Louisiana midstream assets and the close of the sale of Enerplus Global Energy Management Company.
April 30, 2003	Announced execution of letter of intent to sell Eagle Point refinery and related pipeline assets.
May 13, 2003	Announced Executive Management changes.
May 13, 2003	Announced our earnings results for first quarter 2003.

We also furnished information to the SEC under Item 9, Regulation FD, Current Reports on Form 8-K. Current Reports on Form 8-K under Item 9 are not considered to be "filed for purposes of Section 18 of the Securities and Exchange Act of 1934 and are not subject to the liabilities of that section, but are filed to provide full disclosure under Regulation FD."

SIGNATURES

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

EL PASO CORPORATION

Date: May 15, 2003

/s/ D. Dwight Scott

D. Dwight Scott
Executive Vice President and
Chief Financial Officer
(Principal Financial Officer)

Date: May 15, 2003

/s/ Jeffrey I. Beason

Jeffrey I. Beason
Senior Vice President and Controller
(Principal Accounting Officer)

CERTIFICATION

I, Ronald L. Kuehn, Jr., certify that:

1. I have reviewed this quarterly report on Form 10-Q of El Paso Corporation;

2. Based on my knowledge, this quarterly report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this quarterly report;

3. Based on my knowledge, the financial statements, and other financial information included in this quarterly report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this quarterly report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:

a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this quarterly report is being prepared;

b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this quarterly report (the "Evaluation Date"); and

c) presented in this quarterly report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this quarterly report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

/s/ RONALD L. KUEHN, JR.

Ronald L. Kuehn, Jr.
Chairman of the Board and
Chief Executive Officer
(Principal Executive Officer)
El Paso Corporation

Date: May 15, 2003

CERTIFICATION

I, D. Dwight Scott, certify that:

1. I have reviewed this quarterly report on Form 10-Q of El Paso Corporation;

2. Based on my knowledge, this quarterly report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this quarterly report;

3. Based on my knowledge, the financial statements, and other financial information included in this quarterly report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this quarterly report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:

a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this quarterly report is being prepared;

b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this quarterly report (the "Evaluation Date"); and

c) presented in this quarterly report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this quarterly report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

/s/ D. DWIGHT SCOTT

D. Dwight Scott
Executive Vice President and
Chief Financial Officer
(Principal Financial Officer)
El Paso Corporation

Date: May 15, 2003