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 September 30, 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 1-7176

El Paso CGP Company

(Exact Name of Registrant as Specified in its Charter)

Delaware (State or Other Jurisdiction of Incorporation or Organization)	**74-1734212** (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**

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 $1 per share. Shares outstanding on November 12, 2003: 1,000

EL PASO CGP COMPANY MEETS THE CONDITIONS OF GENERAL INSTRUCTION H(1)(a) AND (b) OF FORM 10-Q AND IS THEREFORE FILING THIS REPORT WITH A REDUCED DISCLOSURE FORMAT AS PERMITTED BY SUCH INSTRUCTION.

EL PASO CGP COMPANY

TABLE OF CONTENTS

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

/d	= per day	Mcf	= thousand cubic feet
Bbl	= barrels	Mcfe	= thousand cubic feet of natural gas equivalents
BBtu	= billion British thermal units	MMBtu	= million British thermal units
Bcfe	= billion cubic feet of natural gas equivalents	MMcf	= million cubic feet
MBbls	= thousand barrels	Tcfe	= trillion cubic feet of natural gas equivalents

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 CGP", we are describing El Paso CGP Company and/or our subsidiaries.

PART I — FINANCIAL INFORMATION

Item 1. Financial Statements

EL PASO CGP COMPANY

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

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2003	2002	2003	2002
Operating revenues	$ 506	$ 669	$ 1,854	$3,124
Operating expenses				
Cost of products and services	91	192	383	903
Operation and maintenance	142	166	407	531
Depreciation, depletion and amortization	137	129	417	458
Ceiling test charges	—	—	—	243
(Gain) loss on long-lived assets	5	—	(12)	(21)
Taxes, other than income taxes	14	17	61	58
	389	504	1,256	2,172
Operating income	117	165	598	952
Earnings (losses) from unconsolidated affiliates	8	(5)	(7)	79
Other income	11	29	29	57
Other expenses	—	(1)	(6)	(151)
Interest and debt expense	(103)	(119)	(302)	(326)
Affiliated interest expense, net	(11)	(3)	(25)	(9)
Distributions on preferred interests of consolidated subsidiaries	(1)	(7)	(15)	(28)
Income before income taxes	21	59	272	574
Income taxes	(5)	22	84	189
Income from continuing operations	26	37	188	385
Discontinued operations, net of income taxes	(49)	(93)	(1,187)	(149)
Cumulative effect of accounting changes, net of income taxes	—	—	(21)	14
Net income (loss)	$ (23)	$ (56)	$(1,020)	$ 250

See accompanying notes.

EL PASO CGP COMPANY

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

	September 30, 2003	December 31, 2002
ASSETS		
Current assets		
Cash and cash equivalents	$ 202	$ 128
Accounts and notes receivable		
Customers, net of allowance of $24 in 2003 and $21 in 2002	268	345
Affiliates	475	521
Other	104	187
Inventory	59	61
Assets from price risk management activities	94	102
Assets of discontinued operations	1,575	2,154
Other	174	163
Total current assets	2,951	3,661
Property, plant and equipment, at cost		
Natural gas and oil properties, at full cost	8,086	7,479
Pipelines	6,407	6,522
Power facilities	471	478
Gathering and processing systems	153	279
Other	84	92
	15,201	14,850
Less accumulated depreciation, depletion and amortization	6,688	6,566
Total property, plant and equipment, net	8,513	8,284
Other assets		
Investments in unconsolidated affiliates	1,418	1,528
Assets from price risk management activities	855	956
Goodwill and other intangible assets, net	493	495
Assets of discontinued operations	—	1,911
Other	543	398
	3,309	5,288
Total assets	$14,773	$17,233

See accompanying notes.

EL PASO CGP COMPANY

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

	September 30, 2003	December 31, 2002
LIABILITIES AND STOCKHOLDER'S EQUITY		
Current liabilities		
Accounts payable		
Trade	$ 196	$ 208
Affiliates	325	87
Other	186	261
Current maturities of long-term debt	272	369
Notes payable to affiliates	2,075	2,374
Liabilities from price risk management activities	52	216
Liabilities of discontinued operations	755	1,373
Other	293	273
Total current liabilities	4,154	5,161
Long-term debt	5,055	4,985
Other		
Liabilities from price risk management activities	78	24
Deferred income taxes	1,564	1,753
Liabilities of discontinued operations	—	87
Other	340	270
	1,982	2,134
Commitments and contingencies		
Securities of subsidiaries		
Preferred interests of consolidated subsidiaries	100	400
Minority interests of consolidated subsidiaries	116	253
	216	653
Stockholder's equity		
Common stock, par value $1 per share; authorized and issued 1,000 shares	—	—
Additional paid-in capital	1,497	1,339
Retained earnings	1,901	3,102
Accumulated other comprehensive loss	(32)	(141)
Total stockholder's equity	3,366	4,300
Total liabilities and stockholder's equity	$14,773	$17,233

See accompanying notes.

EL PASO CGP COMPANY

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

	Nine Months Ended September 30,	
	2003	2002
Cash flows from operating activities		
Net income (loss)	$(1,020)	$ 250
Less loss from discontinued operations, net of income taxes	(1,187)	(149)
Net income from continuing operations	167	399
Adjustments to reconcile net income to net cash from operating activities		
Depreciation, depletion and amortization	417	458
Ceiling test charges	—	243
Non-cash gains from trading and power activities	(42)	(479)
Gain on long-lived assets	(12)	(21)
Undistributed earnings of unconsolidated affiliates	69	(25)
Deferred income tax expense (benefit)	44	(41)
Cumulative effect of accounting changes	21	(14)
Other non-cash income items	5	27
Working capital changes	546	773
Non-working capital changes and other	(49)	(159)
Cash provided by continuing operations	1,166	1,161
Cash provided by (used in) discontinued operations	2	(170)
Net cash provided by operating activities	1,168	991
Cash flows from investing activities		
Additions to property, plant and equipment	(857)	(1,019)
Purchases of investments in unconsolidated affiliates	(9)	(178)
Net proceeds from the sale of assets and investments	351	946
Increase in restricted cash	(33)	(3)
Net change in notes receivable from unconsolidated affiliates	(167)	121
Other	21	22
Cash used in continuing operations	(694)	(111)
Cash provided by (used in) discontinued operations	399	(124)
Net cash used in investing activities	(295)	(235)
Cash flows from financing activities		
Payments to retire long-term debt	(627)	(1,173)
Net proceeds from the issuance of long-term debt	288	876
Dividend to parent	(181)	—
Net payments to minority interest holders	(6)	(127)
Change in notes payable to unconsolidated affiliates	—	(55)
Net change in affiliated advances payable	(285)	471
Payments to redeem preferred interests of consolidated subsidiaries	—	(350)
Contributions from (distributions to) discontinued operations	401	(655)
Other	12	(30)
Cash used in continuing operations	(398)	(1,043)
Cash provided by (used in) discontinued operations	(401)	304
Net cash used in financing activities	(799)	(739)
Increase in cash and cash equivalents	74	17
Less increase in cash and cash equivalents related to discontinued operations	—	10
Increase in cash and cash equivalents from continuing operations	74	7
Cash and cash equivalents		
Beginning of period	128	141
End of period	$ 202	$ 148

See accompanying notes.

EL PASO CGP COMPANY

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

	Quarter Ended September 30,		Nine Months Ended September 30	
	2003	2002	2003	2002
Net income (loss)	$(23)	$ (56)	$(1,020)	$ 250
Foreign currency translation adjustments	1	(36)	92	(13)
Unrealized net gains (losses) from cash flow hedging activity				
Unrealized mark-to-market earnings (losses) arising during period (net of income taxes of $12 and $29 in 2003 and $15 and $128 in 2002)	20	(17)	(52)	(212)
Reclassification adjustments for changes in initial value to the settlement date (net of income taxes of $8 and $38 in 2003 and $13 and $78 in 2002)	15	(17)	69	(138)
Other comprehensive income (loss)	36	(70)	109	(363)
Comprehensive income (loss)	$ 13	$(126)	$ (911)	$(113)

See accompanying notes.

EL PASO CGP COMPANY

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

1. Basis of Presentation and Summary of Significant Accounting Policies

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 Current Report on Form 8-K dated September 23, 2003 (which updated the financial statement information originally presented in our 2002 Form 10-K to reclassify our petroleum markets business as a discontinued operation), which includes a summary of our significant accounting policies and other disclosures. The financial statements as of September 30, 2003, and for the quarters and nine months ended September 30, 2003 and 2002, are unaudited. We derived the balance sheet as of December 31, 2002, from the audited balance sheet filed in our Current Report on Form 8-K dated September 23, 2003. In our opinion, we have made all adjustments which are of a normal, recurring nature to fairly present our interim period results. Due to the seasonal nature of our businesses, information for interim periods may not be indicative of our results of operations for the entire year. Our results for all periods presented have been reclassified to reflect our petroleum and coal mining operations as discontinued operations. In addition, prior period information presented in these financial statements includes reclassifications which were made to conform to the current period presentation. These reclassifications had no effect on our previously reported net income or stockholder's equity.

Our accounting policies are consistent with those discussed in our Current Report on Form 8-K dated September 23, 2003, 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 increase in property, plant and equipment is then depreciated over the remaining useful life of the long-lived asset to which that liability relates. An ongoing expense is also recognized for changes in the value of the liability as a result of the passage of time, which we also 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 $21 million, net of income taxes, related to our adoption of SFAS No. 143. We also recorded property, plant and equipment of $111 million and asset retirement obligations of $156 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 them. We currently forecast that these obligations will be met at various times, generally over the next 10 years, based on the expected productive lives of the wells and the estimated timing of plugging and abandoning those wells. The net asset retirement liability as of January 1, 2003 and September 30, 2003, reported in other current and non-current liabilities in our balance sheet, and the changes in the net liability for the nine months ended September 30, 2003, were as follows (in millions):

Liability at January 1, 2003	$156
Liabilities settled in 2003	(29)
Accretion expense in 2003	7
Liabilities incurred in 2003	1
Changes in estimate	(7)
Net liability at September 30, 2003	$128

Our changes in estimate represent changes to the expected amount and timing of payments to settle our asset retirement obligations. These changes primarily result from obtaining new information about the timing of our obligations to plug our natural gas and oil wells and the costs to do so. Had we adopted SFAS No. 143 as of January 1, 2002, our current and non-current retirement liabilities on that date would have been approximately $130 million and our income from continuing operations and net income for the quarter and nine months ended September 30, 2002, would have been lower by $2 million and $6 million.

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 applied the provisions of SFAS No. 146 in accounting for restructuring costs we incurred during 2003. For the quarter and nine months ended September 30, 2003, we recorded $1 million and $10 million of employee severance costs, less income taxes of less than $1 million and $1 million associated with our discontinued operations, substantially all of which had been paid as of June 30, 2003. 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.

Amendment of Statement 133 on Derivative Instruments and Hedging Activities. In April 2003, the Financial Accounting Standards Board (FASB) issued SFAS No. 149, *Amendment of Statement 133 on Derivative Instruments and Hedging Activities.* This statement amends SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* to incorporate several interpretations of the Derivatives Implementation Group (DIG), and also makes several modifications to the definition of a derivative as it was defined in SFAS No. 133. SFAS No. 149 affects contracts entered into or modified after June 30, 2003. There was no initial financial statement impact of adopting this standard, although the FASB and DIG continue to deliberate on the application of the standard to certain derivative contracts, such as power capacity contracts, which may impact our financial statements in the future.

Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity. In May 2003, the FASB issued SFAS No. 150, *Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity*. This statement provides guidance on the classification of financial instruments as equity, as liabilities, or as both liabilities and equity. In particular, the standard requires that we classify all mandatorily redeemable securities as liabilities in the balance sheet. We adopted the provisions of SFAS No. 150 on July 1, 2003, and reclassified $300 million of our Coastal Finance I preferred interests from preferred interests of consolidated subsidiaries to long-term debt in our balance sheet. We also began classifying dividends accrued on the preferred interests as interest and debt expense in our income statement after July 1, 2003. For the quarter and nine months ended September 30, 2003, total dividends were $6 million and $18 million. The third quarter of 2003 dividends of $6 million were recorded in interest expense in our income statement. The first and second quarter of 2003 dividends of $12 million were recorded as distributions on preferred interests of consolidated subsidiaries in our income statement.

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 fair value when they are issued. There was no initial financial statement impact of adopting this standard.

Accounting for Regulated Operations. Our interstate natural gas pipelines and storage operations are subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC) in accordance with the Natural Gas Act of 1938 and Natural Gas Policy Act of 1978. In 1996, we discontinued the application of SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation*. However, as a result of recent changes in our competitive environment and operating cost structures, we are evaluating the applicability of the provisions of SFAS No. 71 to our financial statements. The outcome of this evaluation could result in the restoration of our application of this accounting in some, if not all, of our regulated systems. We expect to complete our current evaluation of the applicability of SFAS No. 71 by the end of the year. For a discussion of differences in accounting for regulated operations, see our Current Report on Form 8-K dated September 23, 2003.

2. Divestitures

During 2003, we completed or announced the sale of a number of assets and investments in each of our business segments. The gains and losses on these sales and any asset impairments recorded on these assets, investments and operations are discussed in Notes 4, 6 and 14.

Segment	Proceeds (In millions)	Significant Asset and Investment Divestitures
Completed as of September 30, 2003		
Pipelines	$ 82	• Panhandle gathering system located in Texas
		• Equity interest in Alliance pipeline and related assets
		• Helium processing operations in Oklahoma
		• Sulfur extraction facility
		• Horsham pipeline in Australia
Production	220	• Natural gas and oil properties located in western Canada, Texas, Louisiana, New Mexico and the Gulf of Mexico
		• Drilling rigs
Field Services	94	• Gathering systems located in Wyoming
		• Midstream assets in the Mid-Continent region
Corporate and Other	3	• Aircraft
Total continuing operations	399[1]	
Discontinued operations	599	• Coal reserves and properties in West Virginia, Virginia and Kentucky
		• Corpus Christi refinery
		• Florida petroleum terminals and tug and barge operations
		• Louisiana lease crude business
		• Petroleum asphalt operations
Total	$998	

(1) Excludes $48 million of costs incurred in preparing assets for disposal, returns of invested capital and cash transferred with assets sold.

Segment	Proceeds[1] (In millions)	Significant Asset and Investment Divestitures
Announced to date		
Pipelines	$ 7	• Equity interest in gas storage facilities
Corporate and Other	25	• Harbortown development
Total continuing operations	32	
Discontinued operations	305	• Eagle Point refinery and related pipeline assets[2]
		• Nitrogen plant
		• Texas lease crude business[3]
		• Pipeline and terminal in the Philippines
Total	$337	

(1) Amounts on sales that have been announced or are under contract for sale are estimates, subject to customary regulatory approvals, final sale negotiations and other conditions.

(2) We have entered into a non-binding letter of intent to sell these assets.

(3) This sale was completed in October 2003.

Each period, we evaluate our potential asset sales 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.* To the extent that all of the criteria of SFAS No. 144 are met, we classify an asset as held for sale or, if appropriate, discontinued operations. For example, El Paso's Board of Directors (or a designated subcommittee of its Board) is required to approve asset dispositions greater than specified thresholds. Unless specific approval is received by its Board (or a designated subcommittee) by the end of a given reporting period to commit to a plan to sell an asset, we would not classify it as held for sale or discontinued operations in that reporting period even if it is management's stated intent to sell the asset. As of December 31, 2002, we had $31 million of long-lived assets classified as held for sale and reflected in current assets in our balance sheet, all of which had been sold as of September 30, 2003. As of September 30, 2003, we had no long-lived assets classified as held for sale and had approximately $1.6 billion of assets classified as discontinued operations as of September 30, 2003 (see Note 6).

We continue to evaluate assets we may sell in the future. As specific assets are identified for divestiture, we will be required to record them at the lower of fair value or historical cost. This may require us to assess them for possible impairment. The amounts of these impairment charges, if any, will generally be based on estimates of the expected fair value of the assets as determined by market data obtained through the divestiture process or by assessing the probability-weighted cash flows of the asset. For a discussion of impairment charges incurred on our long-lived assets, see Note 4; for impairments on discontinued operations, see Note 6; and for impairments on our investments in unconsolidated affiliates, see Note 14.

As of September 30, 2002, we had completed the following asset sales:

Segment	Proceeds (In millions)	Significant Asset and Investment Divestitures
Pipelines	$112	• Natural gas and oil production properties in Texas, Kansas and Oklahoma and their related contracts
Production	772	• Natural gas and oil properties located in Texas and Colorado
Field Services	65	• Dragon Trail processing plant
Total continuing operations	949[1]	
Discontinued operations	31	• A petroleum products terminal
Total	$980	

[1] Excludes $3 million of costs incurred in preparing assets for disposal, returns of invested capital and cash transferred with the assets sold.

3. 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 nine months ended September 30, 2002, we recorded ceiling test charges of $243 million, of which $10 million was charged during the first quarter and $233 million during the second quarter. The 2002 charges include $226 million for our Canadian full cost pool, $10 million for our Brazilian full cost pool and $7 million for other international production operations. Our ceiling test charges were based upon the daily posted natural gas and oil prices at the end of each period, adjusted for oilfield or natural gas gathering hub and wellhead price differences, as appropriate. The 2002 charge for our Canadian full cost pool primarily resulted from a low daily posted price for natural gas at the end of the second quarter of 2002.

For the third quarter 2002, capitalized costs in our United States full cost pool did not exceed the ceiling limit, based upon the daily posted gas and oil prices as of November 1, 2002, adjusted for oilfield or gas gathering hub and wellhead price differences as appropriate. Had we computed the third quarter ceiling test charges based upon the daily posted gas and oil prices as of September 30, 2002, we would have incurred a ceiling test charge of $96 million for our United States full cost pool.

Also, 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 these ceiling test charges since we do not significantly hedge our international production activities. However, we would have incurred an additional charge of $28 million related to our United States full cost pool in 2002.

4. 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, and was as follows:

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2003	2002	2003	2002
	(In millions)			
Net realized gain	$ 5	$ —	$ 36	$21
Asset impairments[1]	(10)	—	(24)	—
Gain (loss) on long-lived assets	$ (5)	$ —	$ 12	21

[1] These amounts exclude approximately $1.3 billion of asset impairments for the nine months ended September 30, 2003, related to our petroleum markets operations that were reclassified as discontinued operations.

Net Realized Gain

Our 2003 net realized gains were primarily related to the sales of the Mid-Continent midstream assets in our Field Services segment, the Table Rock sulfur extraction facility in our Pipelines segment and non-full cost pool assets in our Production segment. Our 2002 net realized gains were primarily related to the sales of expansion rights in our Pipelines segment and the sale of the Dragon Trail processing plant in our Field Services segment.

Asset Impairments

We are required to test assets for possible impairment whenever events or changes in circumstances indicate that the carrying amount of these assets may not be fully recoverable. One event that triggers this test is the expectation that it is more likely than not that we will sell or dispose of the asset before the end of its estimated useful life. Based on El Paso's intent to dispose of a number of our assets, we tested those assets for recoverability during the first nine months of 2003. As a result of these assessments, we recognized impairments of $10 million and $24 million in the third quarter and the first nine months of 2003 related to non-full cost pool Canadian assets in our Production segment and a crude oil pipeline in our Merchant Energy segment. For additional asset impairments on our discontinued operations and investments in unconsolidated affiliates, see Notes 6 and 14.

5. Other Expenses

Other expenses for the quarter and nine months ended September 30, 2002, were $1 million and $151 million. Included in the nine month amount was a $90 million contract termination fee paid by our Eagle Point Cogeneration facility (in our global power division of our Merchant Energy segment) to our Eagle Point refinery (in the petroleum markets division classified as discontinued operations). This payment was eliminated in consolidation since the income associated with the petroleum markets division is reflected in discontinued operations while the power division's expense is included in Merchant Energy's operating results. Other expenses for the nine month period also included $50 million of minority interest in our consolidated subsidiaries.

6. Discontinued Operations

Petroleum Markets Operations

In June 2003, El Paso's Board of Directors authorized the sale of substantially all of our petroleum markets operations, including our Aruba refinery, our Unilube blending operations, our domestic and international terminalling facilities and our petrochemical and chemical plants. The Board's actions were in addition to previous actions approving the sales of our Eagle Point refinery, our asphalt business, our Florida terminal, tug and barge business and our lease crude operations. Based on our intent to dispose of these operations, we were required to adjust these assets to their estimated fair value. As a result, we recognized pre-tax charges during the nine months ended September 30, 2003 totaling $1,366 million related to our petroleum markets assets, which included $929 million related to our Aruba refinery and $252 million related to the impairment of our Eagle Point refinery. These impairments were based on a comparison of the carrying value of our petroleum markets assets to their estimated fair value. Our fair value estimates were based on preliminary market data obtained through the early stages of the sales process and an analysis of expected discounted cash flows. The magnitude of these charges was impacted by a number of factors, including the nature of the assets to be sold, and our established time frame for completing the sales.

In the second quarter of 2003, we entered into a product offtake agreement with Vitol S.A. Inc. (Vitol) for the sale of a number of the products produced at our Aruba refinery. As a result of this contract, Vitol became the single largest customer of our Aruba refinery, purchasing approximately 75 percent of the products produced at that plant. The agreement is for one year with two one-year extensions at Vitol's option. We have the right to terminate the agreement when the refinery is sold.

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. Following the authorization of the sale by El Paso's Board of Directors, we recorded impairment charges of $37 million and $185 million in our loss from discontinued operations during the third quarter and the nine months ended September 30, 2002.

Our petroleum markets operations and our coal mining operations were historically included in our Merchant Energy segment, and are classified as discontinued operations in our financial statements for all of the historical periods presented. All of the assets and liabilities of the remaining discontinued businesses are classified as other current assets and liabilities as of September 30, 2003. The summarized financial results and financial position data of discontinued operations were as follows:

	Petroleum	Coal Mining	Total
		(In millions)	
Operating Results			
Quarter Ended September 30, 2003			
Revenues	$ 917	$ —	$ 917
Costs and expenses	(963)	(1)	(964)
Gain (loss) on long-lived assets	8	(8)	—
Other expense	(2)	—	(2)
Interest and debt expense	(4)	—	(4)
Loss before income taxes	(44)	(9)	(53)
Income taxes	(4)	—	(4)
Loss from discontinued operations, net of income taxes	$ (40)	$ (9)	$ (49)
Quarter Ended September 30, 2002			
Revenues	$ 1,033	$ 75	$ 1,108
Costs and expenses	(1,145)	(95)	(1,240)
Gain (loss) on long-lived assets	3	(37)	(34)
Other income	21	—	21
Loss before income taxes	(88)	(57)	(145)
Income taxes	(31)	(21)	(52)
Loss from discontinued operations, net of income taxes	$ (57)	$ (36)	$ (93)

	Petroleum	Coal Mining	Total
		(In millions)	
Nine Months Ended September 30, 2003			
Revenues	$ 4,621	$ 27	$ 4,648
Costs and expenses	(4,730)	(22)	(4,752)
Loss on long-lived assets	(1,278)	(11)	(1,289)
Other income (expenses)	(16)	1	(15)
Interest and debt expense	(8)	—	(8)
Loss before income taxes	(1,411)	(5)	(1,416)
Income taxes	(230)	1	(229)
Loss from discontinued operations, net of income taxes	$(1,181)	$ (6)	$(1,187)

Operating Results

	Petroleum	Coal Mining	Total
Nine Months Ended September 30, 2002			
Revenues	$ 3,095	$ 243	$ 3,338
Costs and expenses	(3,243)	(259)	(3,502)
Gain (loss) on long-lived assets	4	(185)	(181)
Other income	115	6	121
Interest and debt expense	(13)	—	(13)
Loss before income taxes	(42)	(195)	(237)
Income taxes	(15)	(73)	(88)
Loss from discontinued operations, net of income taxes	$ (27)	$(122)	$ (149)

Financial Position Data

	Petroleum	Coal Mining	Total
September 30, 2003			
Assets of discontinued operations			
Accounts and notes receivables	$ 226	$ —	$ 226
Inventory	441	—	441
Other current assets	97	—	97
Property, plant and equipment, net	678	—	678
Other non-current assets	133	—	133
Total assets	$ 1,575	$ —	$ 1,575
Liabilities of discontinued operations			
Accounts payable	$ 209	$ —	$ 209
Other current liabilities	132	—	132
Notes payable	370	—	370
Environmental remediation reserve	44	—	44
Total liabilities	$ 755	$ —	$ 755
December 31, 2002			
Assets of discontinued operations			
Accounts and notes receivables	$ 1,229	$ 29	$ 1,258
Inventory	636	14	650
Other current assets	79	1	80
Property, plant and equipment, net	1,950	46	1,996
Other non-current assets	65	16	81
Total assets	$ 3,959	$ 106	$ 4,065
Liabilities of discontinued operations			
Accounts payable	$ 1,153	$ 20	$ 1,173
Other current liabilities	180	5	185
Environmental remediation reserve	86	15	101
Other non-current liabilities	1	—	1
Total liabilities	$ 1,420	$ 40	$ 1,460

7. Cumulative Effect of Accounting Changes

On January 1, 2003, we adopted SFAS No. 143. As a result, we recorded a cumulative effect of an accounting change of approximately $21 million, net of income taxes (see Note 1).

In the second quarter of 2002, we also adopted DIG Issue No. C-16, *Scope Exceptions: Applying the Normal Purchases and Sales Exception to Contracts that Combine a Forward Contract and Purchased Option Contract.* One of our unconsolidated affiliates, the Midland Cogeneration Venture Limited Partnership, recognized a gain on a fuel supply contract upon adoption of this new rule, and we recorded a gain of $14 million, net of income taxes, as a cumulative effect of an accounting change in our income statement for our proportionate share of this gain.

8. Financial Instruments and Price Risk Management Activities

The following table summarizes the carrying value of our price risk management assets and liabilities as of September 30, 2003 and December 31, 2002:

	September 30, 2003	December 31, 2002
	(In millions)	
Net assets (liabilities)		
Energy Contracts		
Trading contracts[1]	$ —	$ (4)
Non-trading contracts		
Derivatives designated as hedges	(128)	(146)
Other derivatives	947	968
Net assets from price risk management activities[2]	$ 819	$ 818

(1) Trading contracts are derivative contracts that historically have been 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 are comprised of derivative contracts primarily related to our power restructuring activities at our Eagle Point Cogeneration and our Capitol District Energy Center Cogeneration Associates facilities. For a further discussion of our power restructuring activities, see our Current Report on Form 8-K dated September 23, 2003.

9. Inventory

	September 30, 2003	December 31, 2002
	(In millions)	
Current		
Materials and supplies and other	$59	$61
Non-current		
Turbines[1]	20	20
Total inventory	$79	$81

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

10. Debt and Other Credit Facilities

We had $272 million and $369 million of current maturities of long-term debt at September 30, 2003, and December 31, 2002.

Credit Facilities

In April 2003, El Paso entered into a new $3 billion revolving credit facility, with a $1.5 billion letter of credit sublimit, which matures on June 30, 2005. El Paso's $3 billion revolving credit facility has a borrowing cost of LIBOR plus 350 basis points, letter of credit fees of 350 basis points and commitment fees of 75 basis points on unused amounts of the facility. This facility replaced El Paso's previous $3 billion revolving credit facility. Approximately $1 billion of El Paso's other financing arrangements were also amended to conform the provisions of those obligations to El Paso's $3 billion revolving credit facility. The $3 billion revolving credit facility and those other financing arrangements are secured by our equity in ANR Pipeline Company (ANR), Wyoming Interstate Company Ltd. (WIC), ANR Storage Company and our equity in the companies that own the assets that collateralize the Clydesdale financing arrangement discussed below.

In April 2003, El Paso removed us as a borrower under its $1 billion 3-year revolving credit and competitive advance facility, which expired on August 4, 2003.

Consolidations

During the second quarter of 2003, El Paso amended several financing and other agreements in connection with its new $3 billion revolving credit agreement. These amendments were completed to accomplish several objectives, including (i) simplifying its capital structure by eliminating several "off-balance sheet" obligations and replacing them with direct obligations, and (ii) strengthening the overall collateral package available to its financial lenders. Of these amendments, one impacted us directly and is discussed below.

Aruba. We amended an operating lease at our Aruba facility to provide a full guarantee to the parties who invested in the lessor and to allow the third party and certain lenders to share in the collateral package that was provided to the banks under El Paso's new $3 billion revolving credit facility. This guarantee reduced the investor's risk of loss of its investment, resulting in our controlling the lessor. As a result, we consolidated the lessor during the second quarter of 2003, increasing our total property, plant and equipment by $370 million (prior to an impairment charge we recorded on these assets of $50 million) and increasing our long-term debt by $370 million. As a result of our intent to exit substantially all of our petroleum markets operations, these leased assets and associated debt were reclassified as discontinued operations.

Long-Term Debt Obligations

During 2003, we have entered into and retired several debt financing obligations:

Date	Company	Type	Interest Rate	Principal	Net Proceeds[(1)]/ Retirements	Due Date
				(In millions)		
Issuance						
March	ANR	Senior notes	8.875%	$300	$288	2010
Retirements						
January-September	El Paso CGP	Long-term debt	Various	$ 85	$ 85	
February	El Paso CGP	Long-term debt	4.49%	240	240	
July	El Paso CGP	Note	Floating rate	200	200	
August	El Paso CGP	Senior debentures	9.75%	102	102	
		Retirements through September 30, 2003		$627	$627	

(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 other general corporate and investment purposes.

We reclassified $300 million of our mandatorily redeemable preferred securities of Coastal Finance I to long-term debt as a result of the adoption of SFAS No. 150 (see Notes 1 and 11).

Restrictive Covenants

We have entered into debt instruments and guaranty agreements that contain covenants such as limitations on debt levels, limitations on liens securing debt and guarantees, limitations on mergers and on sales of assets, capitalization requirements and dividend limitations. A breach of any of these covenants could potentially accelerate our debt and other financial obligations and that of our subsidiaries.

One of the most significant debt covenants is that we must maintain a minimum net worth of $850 million.

In addition, we have indentures associated with our public debt that contain cross-acceleration provisions in the event of defaults greater than $5 million.

As part of El Paso's new $3 billion revolving credit facility, our subsidiaries, ANR and, upon the maturity of El Paso's Clydesdale financing transaction, Colorado Interstate Gas Company (CIG), cannot incur incremental debt if the incurrence of this incremental debt would cause their debt to EBITDA ratio (as defined in El Paso's new $3 billion revolving credit facility agreement) for that particular company to exceed 5 to 1. Additionally, the proceeds from the issuance of debt by the pipeline company borrowers can only be used for maintenance and expansion capital expenditures or investments in other FERC-regulated assets, to fund working capital requirements, or to refinance existing debt. As of September 30, 2003, we were in compliance with these covenants.

Other Financing Arrangements

The equity in some of our assets, along with other El Paso assets, collateralize a financing arrangement established by El Paso referred to as Clydesdale. In April 2003, El Paso restructured the Clydesdale financing arrangement into a new term loan that amortizes in equal quarterly amounts of $100 million, which began in May 2003, and El Paso guaranteed the third party equity. These actions resulted in the consolidation of the term loan by El Paso in the second quarter of 2003. 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. As of September 30, 2003, the balance on the Clydesdale term loan was $521 million. In November 2003, El Paso made its quarterly payment of $100 million and retired an additional $7 million on this term loan.

11. Preferred Interests of Consolidated Subsidiaries

In May 1998, we formed Coastal Finance I, an indirect wholly owned business trust, to generate funds for investment and general operating purposes. During the third quarter of 2003, $300 million of our mandatorily redeemable preferred securities outstanding was reclassified as a long-term debt on our balance sheet as a result of the adoption of SFAS No. 150 (see Notes 1 and 10).

12. Commitments and Contingencies

Legal Proceedings

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 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, attorneys' 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. Plaintiffs' motion to file another amended petition to narrow the proposed class to royalty owners in wells in Kansas, Wyoming and Colorado was granted on July 28, 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 ten such lawsuits in New York, one in New Hampshire, one in Massachusetts, three in Connecticut and one in Illinois. The plaintiffs generally seek remediation of their groundwater and prevention of future contamination and a variety of compensatory damages as well as punitive damages, attorney's fees, and court costs. In the case filed in Illinois, certification of a national plaintiff's class of certain water providers is requested. Our costs and legal exposure related to these lawsuits 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 September 30, 2003, we had approximately $33 million accrued for all outstanding legal matters. Approximately $5 million of the accrual was related to our discontinued operations.

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 September 30, 2003, we had accrued approximately $148 million for expected remediation costs at current and former operated sites and associated onsite, offsite and groundwater technical studies, which we anticipate incurring through 2027. Approximately $50 million of the accrual was related to our discontinued operations.

Our reserve estimates range from approximately $148 million to approximately $251 million. Our accrual represents a combination of two estimation methodologies. First, where the most likely outcome can be reasonably estimated, that cost has been accrued ($46 million). Second, where the most likely outcome cannot be estimated, a range of costs is established ($102 million to $205 million) and the lower end of the range has been accrued. By type of site, our reserves are based on the following estimates of reasonably possible outcomes.

Sites	September 30, 2003 Low	High
	(In millions)	
Operating	$118	$183
Non-operating	25	60
Superfund	5	8

Below is a reconciliation of our accrued liability as of September 30, 2003 (in millions):

Balance as of January 1, 2003	$171
Additions/adjustments for remediation activities	(2)
Payments for remediation activities	(21)
Balance as of September 30, 2003	$148

In addition, we expect to make capital expenditures for environmental matters of approximately $199 million in the aggregate for the years 2003 through 2008. These expenditures primarily relate to compliance with clean air regulations. For the remainder of 2003, we estimate that our total remediation expenditures will be approximately $8 million.

Coastal Eagle Point. 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. The Orders allege noncompliance with the New Jersey Air Pollution Control Act (the Act) pertaining to excess emissions reported since 1998 by our Eagle Point refinery in Westville, New Jersey. On February 24, 2003, EPA Region 2 issued a Compliance Order alleging violations that included failure to monitor all components and failure to timely repair leaking components. The alleged violations were identified during a 1999 EPA audit of the Leak Detection and Repair program. Our Eagle Point refinery resolved the claims of the United States and the State of New Jersey in a Consent Decree on September 30, 2003, pursuant to the EPA's refinery enforcement initiative. We agreed to pay a civil penalty of $1.25 million to the United States and $1.25 million to New Jersey. We will contribute $1.0 million to an environmentally beneficial project near the refinery. Our Eagle Point refinery will invest an estimated $3 to $7 million to upgrade the plant's environmental controls by 2008. This settlement is subject to public comment and court approval.

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 26 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 September 30, 2003, we have estimated our share of the remediation costs at these sites to be between $5 million and $8 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 estimating our liabilities. Accruals for these issues are included in the previously indicated estimates for Superfund sites.

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

Marketing Affiliate NOPR. In September 2001, the FERC issued a Notice of Proposed Rulemaking (NOPR) proposing 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. We have filed comments with the FERC addressing our concerns with the proposed rules, participated in a public conference and filed additional comments. 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 Policy. In July 2002, the FERC issued a Notice of Inquiry (NOI) that sought comments regarding its 1996 policy of permitting pipelines to enter into negotiated rate transactions. We have entered into those 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. El Paso's pipelines and others filed comments on the NOI.

In July 2003, the FERC issued an order that prospectively prohibits pipelines from negotiating rates based upon natural gas commodity price indices and imposes certain new filing requirements to ensure the transparency of negotiated rate transactions. Requests for rehearing were filed on August 25, 2003 and remain pending. We do not expect the order on rehearing will have a material effect on us.

Cash Management Rule. On October 23, 2003, the FERC approved a rule that requires a FERC-regulated entity to file its cash management agreement with the FERC, maintain records of transactions involving its participation in the cash management program, compute its proprietary capital ratio quarterly based on criteria established by the FERC, and notify the FERC 45 days after the end of a calendar quarter whether its proprietary capital ratio falls below 30 percent and subsequently when its proprietary capital ratio returns to or exceeds 30 percent. In the rule, the FERC stated that the requirements imposed by the rule are not in the nature of a regulation governing participation in cash management programs and that the rule does not dictate the content or terms for participating in a cash management program. Although the rule is subject to rehearing, we do not believe an order on rehearing will have a material effect on us.

On September 10, 2003, the Office of Executive Director of Regulatory Audits completed an industry-wide audit of the FERC Form 2 related to cash management. The audit included our affiliates, El Paso Natural Gas Company (EPNG) and Mojave Pipeline Company. The audit did not identify any instances of non-compliance with the FERC's reporting and recording requirements but recommended that both EPNG and Mojave revise and update their existing cash management agreements with El Paso. Our other pipelines affiliates are in the process of reviewing and revising their cash management agreements pursuant to this recommendation.

Pipeline Safety Notice of Proposed Rulemaking. In January 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. Although we cannot predict the outcome of this rulemaking, we do not expect the order to have a material effect on us.

FERC Inquiry. On February 26, 2003, El Paso received a letter from the Office of the Chief Accountant at the FERC requesting details of its announcement of 2003 asset sales and plans for ANR and our pipeline affiliate to issue a combined $700 million of long-term notes. The letter requested that El Paso explain how it intended to use the proceeds from the issuance of the notes and if the notes were to be included in El Paso's pipeline affiliates', including ANR, capital structure for rate-setting purposes. El Paso's response to the FERC was filed on March 12, 2003. On April 2, 2003, El Paso received an additional request for information, to which we fully responded on April 15, 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 possible that these matters could impact our debt rating and credit rating. Further, for environmental matters, it is 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 our cash flows in the periods these events occur.

Other

Economic Conditions in the Dominican Republic. Recent developments in the economic and financial situation in the Dominican Republic have led to a devaluation of the Dominican peso of approximately 53 percent against the U.S. dollar during 2003 (through September 30, 2003) and an increase in the local inflation rate of approximately 25 percent for the same period. A stand-by agreement with the International Monetary Fund (IMF) received final approval of the IMF Board in August. The Dominican government maintains that the accord could lead to approximately $1.2 billion in disbursements from multilaterals over the next 24 months and will serve to restore consumer and investor confidence in the banking system and economic policy framework, stabilize the exchange rate and avoid a liquidity crisis. An initial disbursement of funds was made in August 2003, but further disbursements are pending approval by the IMF.

We have investments in power projects in the Dominican Republic with an aggregate exposure of approximately $100 million. We own a 48.33 percent interest in a 67 megawatt heavy fuel oil fired power project known as the CEPP project. We also own a 24.99 percent interest in a 513 megawatt power generating complex known as Itabo. As a consequence of economic conditions described above, and due to their inability to pass through higher energy prices to their consumers, the local distribution companies that purchase the electrical output of these facilities have been delinquent in their payments to CEPP and Itabo, as well as the other generating facilities in the Dominican Republic since April 2003. The failure to pay generators has resulted in the inability of the generators to purchase fuel required for the production of energy which has caused significant energy shortfalls in the country. We currently believe that the economic difficulties in the Dominican Republic will not have a material adverse effect on our investments, but we will continue to monitor those conditions and are working with the government and the local distribution companies to resolve these issues.

Cases

The MTBE cases discussed above and filed in New York are: *County of Suffolk and Suffolk County Water Authority v. Amerada Hess Corp., et al.,* filed on October 9, 2002, in the Supreme Court of the State of New York, County of Suffolk, and the following eight cases filed on September 30, 2003 in the Supreme Court of the State of New York, County of New York: *County of Nassau v. Amerada Hess, et al., Village of Mineola, Inc. and Water Dept. of the Village of Mineola v. Atlantic Richfield, et al., West Hempstead Water District v. Atlantic Richfield Co., et al., Carle Place Water District v. Atlantic Richfield Co., et al., Town of Southampton v. Atlantic Richfield Co., et al., Village of Hempstead v. Atlantic Richfield Co., et al., Town of East Hampton v. Atlantic Richfield Co., et al.,* and *Westbury Water District v. Atlantic Richfield Co., et al.* The tenth case *Water Authority of Western Nassau v. Atlantic Richfield Co., et al.,* was filed on October 1, 2003 in the Supreme Court of the State of New York, County of New York.

The MTBE case filed in New Hampshire is *State of New Hampshire v. Amerada Hess Corp. et al.,* filed in New Hampshire Superior Court, County of Merrimack, on September 30, 2003.

The MTBE case filed in Massachusetts is *Brimfield Housing Authority (Brimfield, MA), et al. v. Amerada Hess Corporation, et al.,* filed in Massachusetts Superior Court, County of Suffolk, on September 30, 2003.

The three MTBE cases filed in Connecticut are *Childhood Memories v. Amerada Hess Corporation, et al.,* filed in Connecticut Superior Court, Judicial District of Litchfield, on September 30, 2003, *Columbia Board of Education, Horace Porter School v. Amerada Hess Corporation, et al.,* filed in Connecticut Superior Court, Judicial District of Tolland, on September 30, 2003, and *Canton Board of Education, Cherry Brook School v. Amerada Hess Corporation, et al.,* filed in Connecticut Superior Court, Judicial District of Hartford, on September 30, 2003.

The MTBE case filed in Illinois is *Village of East Alton, Individually and on behalf of all others similarly situated v. Amerada Hess Corporation, et al.,* filed in the Circuit Court, Third Judicial Circuit, Madison County, Illinois, on September 30, 2003.

Commitments and Purchase Obligations

During 2003, we entered into purchase obligations to acquire pipe and other equipment that will be used in our Cheyenne Plains Pipeline project. Our total commitment is approximately $96 million and will be paid during 2004. El Paso has guaranteed this purchase commitment.

13. 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. We reclassified our historical coal mining operation in the second quarter of 2002 and our petroleum markets and chemical operations in the second quarter of 2003 from our Merchant Energy segment to discontinued operations in our financial statements. Merchant Energy's operating results for all periods presented 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 net income (loss) adjusted for (i) items that do not impact our income (loss) from continuing operations, such as extraordinary items, discontinued operations and the impact of accounting changes, (ii) income taxes, (iii) interest and debt expense and (iv) distributions on preferred interests of consolidated subsidiaries. Our business operations consist of both consolidated businesses as well as substantial investments in unconsolidated affiliates. We believe EBIT, which includes the results of both these consolidated and unconsolidated operations, is useful to our investors because it allows them to more effectively evaluate the performance of all of our businesses and investments. Also, we exclude interest and debt expense and distributions on preferred interests of consolidated subsidiaries so that investors may evaluate our operating results without regard to our financing methods or capital structure. EBIT may not be comparable to measures 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 from continuing operations are presented below:

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2003	2002	2003	2002
	(In millions)			
Total EBIT	$ 136	$ 188	$ 614	$ 937
Interest and debt expense	(103)	(119)	(302)	(326)
Affiliated interest expense, net	(11)	(3)	(25)	(9)
Distributions on preferred interests of consolidated subsidiaries	(1)	(7)	(15)	(28)
Income taxes	5	(22)	(84)	(189)
Income from continuing operations	$ 26	$ 37	$ 188	$ 385

The following tables reflect our segment results as of and for the periods ended September 30 (in millions):

	Quarter Ended September 30,					
	Pipelines	Production	Field Services	Merchant Energy	Corporate & Other[(1)]	Total
2003						
Revenues from external customers	$193	$161	$ 69	$ 58	$ —	$ 481
Intersegment revenues	—	42	—	1	(18)	25[(2)]
Operation and maintenance	57	54	7	28	(4)	142
Depreciation, depletion and amortization	28	101	1	5	2	137
(Gain) loss on long-lived assets	(2)	(1)	—	10	(2)	5
Operating income (loss)	75	40	8	(9)	3	117
Earnings (losses) from unconsolidated affiliates	15	2	(1)	(8)	—	8
Other income	2	1	—	4	4	11
EBIT	$ 92	$ 43	$ 7	$ (13)	$ 7	$ 136
2002						
Revenues from external customers	$188	$223	$110	$ 117	$ (66)	$ 572
Intersegment revenues	8	22	21	(29)	75	97[(2)]
Operation and maintenance	63	61	11	33	(2)	166
Depreciation, depletion and amortization	27	92	3	4	3	129
Operating income	70	69	12	14	—	165
Earnings (losses) from unconsolidated affiliates	24	2	(49)	19	(1)	(5)
Other income	2	—	1	3	22	28
EBIT	$ 96	$ 71	$(36)	$ 36	$ 21	$ 188

(1) Includes our Corporate 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) Relates to intercompany activities between our continuing operating segments and our discontinued petroleum markets operations.

	Nine Months Ended September 30,					
	Pipelines	Production	Field Services	Merchant Energy	Corporate & Other[(1)]	Total
2003						
Revenues from external customers	$694	$631	$270	$ 182	$ —	$1,777
Intersegment revenues	—	99	25	(7)	(40)	77[(2)]
Operation and maintenance	173	138	23	75	(2)	407
Depreciation, depletion and amortization	82	309	6	12	8	417
(Gain) loss on long-lived assets	(11)	8	(18)	11	(2)	(12)
Operating income (loss)	317	220	46	20	(5)	598
Earnings (losses) from unconsolidated affiliates	54	3	(80)	16	—	(7)
Other income	—	2	—	10	11	23
EBIT	$371	$225	$(34)	$ 46	$ 6	$ 614
2002						
Revenues from external customers	$656	$888	$303	$1,179	$ —	$3,026
Intersegment revenues	28	76	42	(18)	(30)	98[(2)]
Operation and maintenance	181	181	35	121	13	531
Depreciation, depletion and amortization	88	334	10	16	10	458
Ceiling test charges	—	243	—	—	—	243
Gain on long-lived assets	(11)	—	(9)	—	(1)	(21)
Operating income (loss)	298	151	44	485	(26)	952
Earnings (losses) from unconsolidated affiliates	79	2	(48)	47	(1)	79
Other income (expenses)	11	—	—	(126)	21	(94)
EBIT	$388	$153	$ (4)	$ 406	$ (6)	$ 937

(1) Includes our Corporate 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) Relates to intercompany activities between our continuing operating segments and our discontinued petroleum markets operations.

Total assets by segment are presented below:

	September 30, 2003	December 31, 2002
	(In millions)	
Pipelines	$ 5,759	$ 5,175
Production	4,547	4,370
Field Services	228	417
Merchant Energy	2,375	2,446
Total segment assets	12,909	12,408
Corporate and other	289	760
Discontinued operations	1,575	4,065
Total consolidated assets	$14,773	$17,233

14. 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, and affiliates in which we hold a greater than 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 $2 million and $10 million for the quarters ended, and $11 million and $28 million for the nine months ended September 30, 2003 and 2002.

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2003	2002	2003	2002
	(In millions)			
Operating results data:				
Operating revenues	$198	$238	$597	$596
Operating expenses	166	173	447	403
Income from continuing operations	5	40	58	113
Net income	5	40	58	113

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 quarter ended June 30, 2003, we recorded impairment charges of $80 million related to our investments in Dauphin Island Gathering Partners and Mobile Bay Processing Partners in our Field Services segment due to our anticipation of incurring a loss from selling our interests in these investments.

Related Party Transactions

We participate in El Paso's cash management program which matches short-term cash surpluses and needs of its participating affiliates, thus minimizing total borrowing from outside sources. See Note 12 for further discussion on the FERC's Rule on Cash Management. As of September 30, 2003, and December 31, 2002, we had borrowed $2,075 million and $2,374 million. The market rate of interest as of September 30, 2003, and December 31, 2002, was 3.5% and 1.5%. In addition, we had a demand note receivable with El Paso of $232 million and $199 million at September 30, 2003, and December 31, 2002. The interest rate for this demand note receivable was 1.6% at September 30, 2003, and 2.2% at December 31, 2002.

At September 30, 2003, and December 31, 2002, we had current accounts and notes receivable from related parties of $243 million and $322 million. These balances were incurred in the normal course of our business. In addition, we had a non-current note receivable from a related party of $261 million and $126 million included in other non-current assets at September 30, 2003, and at December 31, 2002.

At September 30, 2003, and December 31, 2002, we had other accounts payable to related parties of $325 million and $87 million. These balances were incurred in the normal course of business.

During the third quarter of 2003, we distributed $181 million of operating cash to El Paso to reduce its obligations associated with the Clydesdale financing arrangement. A portion of our operating units serve as collateral under this arrangement. See Note 10 for a discussion of the Clydesdale financing arrangement.

In March 2002, we acquired assets with a net book value, net of deferred taxes, of approximately $8 million from El Paso.

Also, in March 2002, we sold natural gas and oil properties to El Paso. Net proceeds from these sales were $404 million, and we did not recognize a gain or loss on the properties sold. The proceeds exceeded the net book value by $32 million, and we recorded these proceeds as an increase to paid-in-capital.

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 and El Paso's subsidiaries:

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2003	2002	2003	2002
	(In millions)			
Operating revenues	$295	$469	$874	$1,285
Cost of sales	2	52	69	158
Charges from affiliates	89	104	294	307
Other income	1	2	4	5

15. New Accounting Pronouncements Issued But Not Yet Adopted

As of September 30, 2003, there were several accounting standards and interpretations that had been issued, but not yet adopted by us. Below is a discussion of the more significant standards that could impact us.

Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51

In January 2003, the FASB 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 a company to 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. On October 9, 2003, the FASB issued FASB Staff Position, FSP FIN No. 46-6, *Effective Date of FASB Interpretation No. 46, Consolidation of Variable Interest Entities*. This staff position deferred our required adoption date of FIN No. 46 to the fourth quarter of 2003.

Upon adoption of this standard, we will be required to consolidate the preferred equity holder of one of our consolidated subsidiaries, Coastal Securities Company Limited. The impact of this consolidation will be an increase in long-term debt and a decrease in preferred interests in consolidated subsidiaries by $100 million. We also continue to evaluate our joint venture and financing arrangements to assess the impact, if any, of FIN No. 46 on those arrangements.

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 Current Report on Form 8-K dated September 23, 2003, and the financial statements and notes presented in Item 1 of this Form 10-Q.

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 net income (loss) adjusted for (i) items that do not impact our income (loss) from continuing operations, such as extraordinary items, discontinued operations and the impact of accounting changes, (ii) income taxes, (iii) interest and debt expense and (iv) distributions on preferred interests of consolidated subsidiaries. Our business operations consist of both consolidated businesses as well as substantial investments in unconsolidated affiliates. We believe EBIT, which includes the results of both these consolidated and unconsolidated operations, is useful to our investors because it allows them to more effectively evaluate the performance of all of our businesses and investments. Also, we exclude interest and debt expense and distributions on preferred interests of consolidated subsidiaries so that investors may evaluate our operating results without regard to our financing methods or capital structure. EBIT may not be comparable to measures 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 following is a reconciliation of our operating income to our EBIT and our EBIT to our net income (loss) for the periods ended September 30:

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2003	2002	2003	2002
	(In millions)			
Operating revenues	$ 506	$ 669	$ 1,854	$ 3,124
Operating expenses	(389)	(504)	(1,256)	(2,172)
Operating income	117	165	598	952
Earnings (losses) from unconsolidated affiliates	8	(5)	(7)	79
Other income (expense)	11	28	23	(94)
EBIT	136	188	614	937
Interest and debt expense	(103)	(119)	(302)	(326)
Affiliated interest expense, net	(11)	(3)	(25)	(9)
Distributions on preferred interests of consolidated subsidiaries	(1)	(7)	(15)	(28)
Income taxes	5	(22)	(84)	(189)
Income from continuing operations	26	37	188	385
Discontinued operations, net of income taxes	(49)	(93)	(1,187)	(149)
Cumulative effect of accounting changes, net of income taxes	—	—	(21)	14
Net income (loss)	$ (23)	$ (56)	$(1,020)	$ 250

Overview of Results of Operations

Below are our results of operations (as measured by EBIT) by 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. We reclassified our historical coal mining operation in the second quarter of 2002 and our petroleum markets and chemical operations in the second quarter of 2003 from our Merchant Energy segment to discontinued operations in our financial statements. Merchant Energy's results for all periods presented reflect this change. For a further discussion of charges and other income and expense items impacting the results below, see Item 1, Notes 1 through 5 and 14.

	Quarter Ended September 30,		Nine Months Ended September 30,	
EBIT by Segment	2003	2002	2003	2002
	(In millions)			
Pipelines	$ 92	$ 96	$371	$388
Production	43	71	225	153
Field Services	7	(36)	(34)	(4)
Merchant Energy	(13)	36	46	406
Segment EBIT	129	167	608	943
Corporate and other	7	21	6	(6)
Consolidated EBIT	$136	$188	$614	$937

Pipelines

Our Pipelines segment owns and operates our interstate transmission businesses. For a further discussion of the business activities of our Pipelines segment, see our Current Report on Form 8-K dated September 23, 2003. Results of our Pipelines segment operations were as follows for the periods ended September 30:

	Quarter Ended September 30,		Nine Months Ended September 30,	
Pipelines Segment Results	2003	2002	2003	2002
	(In millions, except volume amounts)			
Operating revenues	$ 193	$ 196	$ 694	$ 684
Operating expenses	(118)	(126)	(377)	(386)
Operating income	75	70	317	298
Other income	17	26	54	90
EBIT	$ 92	$ 96	$ 371	$ 388
Throughput volumes (BBtu/d)(1)	7,334	7,471	8,219	8,004

(1) Throughput volumes for the quarter and nine months ended September 30, 2002, exclude 199 BBtu/d and 210 BBtu/d related to our equity investment in the Alliance pipeline system which was sold. Throughput volumes also exclude volumes transported between entities within the Pipelines segment. Prior period volumes have been restated to reflect current year presentation which includes billable transportation throughput volume for storage withdrawal.

Third Quarter 2003 Compared to Third Quarter 2002

Operating revenues for the quarter ended September 30, 2003, were $3 million lower than the same period in 2002. The decrease was due to $8 million from lower natural gas recovered in excess of amounts used in operations, a $3 million reduction of Dakota gasification facility purchased gas resales following a FERC approved contract buyout effective August 1, 2003 and $3 million of lower transportation and storage revenues due to contract changes. These decreases were offset by $10 million from higher revenues due to completed system expansions and new transportation contracts and an increase of $3 million in gas processing revenues resulting from higher liquids prices.

Operating expenses for the quarter ended September 30, 2003, were $8 million lower than the same period in 2002. The decrease was due to lower gas used for system supply requirements of $9 million and $2 million from lower general and administrative costs in 2003. These decreases were offset by a net increase of $3 million related to the FERC approved gas purchase contract buyout related to the Dakota gasification facility and an increase of $2 million due to favorable property tax adjustments recorded in 2002.

Other income for the quarter ended September 30, 2003, was $9 million lower than the same period in 2002 due to lower equity earnings of $6 million resulting from the sale of our interests in the Alliance pipeline system completed in the first quarter of 2003 and $3 million from the favorable resolution of uncertainties in 2002 associated with the 2001 sale of our Gulfstream pipeline project.

Nine Months Ended 2003 Compared to Nine Months Ended 2002

Operating revenues for the nine months ended September 30, 2003, were $10 million higher than the same period in 2002. The increase was due to higher revenues of $26 million due to completed system expansions and new transportation contracts, $17 million from higher realized prices in 2003 on the resale of natural gas purchased from the Dakota gasification facility which was partially offset by $5 million from lower gas resales due to a FERC approved buyout of the Dakota gas purchase contract effective August 1, 2003 and $11 million from higher prices on natural gas recovered in excess of amounts used in operations. Also contributing to the increase was a $9 million increase in gas processing revenues resulting from higher liquids prices and $7 million from higher storage gas sales. These increases were partially offset by $48 million from lower revenues due to CIG's sale of the Panhandle field and other production properties in July 2002 and a $10 million decrease in transportation and storage revenues due to contract changes.

Operating expenses for the nine months ended September 30, 2003, were $9 million lower than the same period in 2002. The decrease was due to a $27 million decrease in operating costs due to CIG's sale of Panhandle field and other production properties in July 2002, additional accruals in the second quarter of 2002 of $10 million on estimated liabilities to assess and remediate our environmental exposure due to an ongoing evaluation of the exposure at our facilities, a $9 million gain on the buyout of a gas purchase contract related to the sale of CIG's Table Rock sulfur extraction facility and the sale of non-pipeline assets in 2003 and lower gas used for system supply requirements of $7 million. The decreases were offset by $16 million from higher prices on natural gas purchased at the Dakota gasification facility along with the impact of the FERC approved gas purchase contract buyout of $6 million which was partially offset by $5 million from lower gas purchases following the termination of the Dakota contract, an $11 million gain on the sale of pipeline expansion rights in 2002, $7 million of favorable general and administrative allocations adjustments received in 2002, lower benefit costs in 2002 of $6 million and a $2 million of favorable property tax adjustments recorded in 2002.

Other income for the nine months ended September 30, 2003, was $36 million lower than the same period in 2002. The decrease was due to $16 million from lower equity earnings resulting from the sale of our interest in the Alliance pipeline system completed in the first quarter of 2003, $11 million from the favorable resolution of uncertainties in 2002 associated with the sale of our interests in the Iroquois and Empire State pipeline systems and Gulfstream pipeline project in 2001 and $7 million from lower equity earnings from our investment in Great Lakes primarily due to a favorable use tax settlement recorded by Great Lakes in the first quarter of 2002.

Production

Our Production segment conducts our natural gas and oil exploration and production activities. Our operating results are driven by a variety of factors including the ability to locate and develop economic natural gas and oil reserves, extract those reserves with minimal production costs, sell the products at attractive prices and operate at a low total cost level.

Since December 31, 2001, we have sold over 1.8 Tcfe of proved reserves in multiple sales transactions with various third parties and our parent. The cumulative amount of the reserves sold represented over 43 percent of our year end 2001 total reserve base, and generated total cash proceeds of approximately $1.5 billion. These sales were conducted as part of our parent's overall efforts to reduce debt and improve its liquidity position. These sales, which included proved developed producing reserves, combined with normal production declines, mechanical failures on certain producing wells and higher finding and development costs, have resulted in our total equivalent production levels declining each quarter since the first quarter of 2002. For the first nine months of 2003, our total equivalent production has declined approximately 97 Bcfe or 39 percent as compared to the same period in 2002. Future trends in production will be dependent upon the amount of capital allocated to our Production segment, the level of success in our drilling programs and any future sales activities relating to our proved reserves.

As further described in our Current Report on Form 8-K dated September 23, 2003, Production has historically engaged in hedging activities on its natural gas and oil production to stabilize cash flows and to reduce the risk of downward commodity price movements on its sales. As of September 30, 2003, we have hedged approximately 21 million MMBtu's of our remaining anticipated natural gas production for 2003 at a NYMEX Henry Hub price of $3.71 per MMBtu before regional price differentials and transportation costs.

Our depletion rate is determined under the full cost method of accounting. We expect a higher depletion rate in future periods as a result of higher finding and development costs experienced this year, coupled with a lower reserve base due to the asset sales mentioned above. For the fourth quarter of 2003, we expect our domestic unit of production depletion rate to be approximately $2.29 per Mcfe.

During the nine months ended September 30, 2003, we spent approximately $682 million on capital expenditures. In October 2003, we entered into agreements with a wholly owned subsidiary of Lehman Brothers (Lehman), an investment bank, and a wholly owned subsidiary of Nabors Industries Ltd. (Nabors) that will collectively result in an additional $160 million of drilling activity over the next nine to 12 months. Lehman will contribute 50 percent of an estimated $230 million total cost to develop a specified package of wells in exchange for a 50 percent net profits interest (cash proceeds available after royalties and operating costs have been paid), and Nabors will contribute 20 percent in exchange for a 20 percent net profits interest in such package of wells. Once a specified payout is achieved, Lehman's and Nabors' net profits interests will convert to an overriding royalty interest in the wells for the remainder of the wells' productive lives. El Paso will contribute the remaining 30 percent of the $230 million of capital as part of its existing 2003 and 2004 capital budget. Under the terms of the agreements, all parties have a right to cease further investment with 30 days notice.

As of January 1, 2003, our reserve estimates were prepared internally by our Production segment and reviewed by Huddleston & Co., Inc. During the fourth quarter of 2003, we appointed Ryder Scott Co. as our primary reservoir engineer.

Results of our Production segment operations were as follows for the periods ended September 30:

Production Segment Results	Quarter Ended September 30, 2003	Quarter Ended September 30, 2002	Nine Months Ended September 30, 2003	Nine Months Ended September 30, 2002
	(In millions, except volumes and prices)			
Operating revenues:				
Natural gas	$ 164	$ 208	$ 603	$ 834
Oil, condensate and liquids	40	39	119	125
Other	(1)	(2)	8	5
Total operating revenues	203	245	730	964
Transportation and net product costs	(7)	(14)	(33)	(39)
Total operating margin	196	231	697	925
Operating expenses(1)	(156)	(162)	(477)	(774)
Operating income	40	69	220	151
Other income	3	2	5	2
EBIT	$ 43	$ 71	$ 225	$ 153
Volumes and prices				
Natural gas				
Volumes (MMcf)	35,597	59,625	121,781	208,356
Average realized prices with hedges ($/Mcf)(2)	$ 4.61	$ 3.48	$ 4.95	$ 4.00
Average realized prices without hedges ($/Mcf)(2)	$ 5.02	$ 2.98	$ 5.65	$ 2.85
Average transportation costs ($/Mcf)	$ 0.18	$ 0.14	$ 0.22	$ 0.13
Oil, condensate and liquids				
Volumes (MBbls)	1,612	1,723	4,598	6,410
Average realized prices with hedges ($/Bbl)(2)	$ 24.97	$ 22.57	$ 25.91	$ 19.50
Average realized prices without hedges ($/Bbl)(2)	$ 24.97	$ 22.92	$ 25.91	$ 19.38
Average transportation costs ($/Bbl)	$ 0.87	$ 0.33	$ 0.85	$ 0.66

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

(2) Prices are stated before transportation costs.

Third Quarter 2003 Compared to Third Quarter 2002

Operating revenues for the quarter ended September 30, 2003, were $42 million lower than the same period in 2002. Our natural gas revenues, including the impact of hedges, were $44 million lower in the third quarter of 2003. Our 2003 natural gas production volumes decreased by 40 percent, resulting in an $84 million decrease in revenues versus the same period in 2002. Realized natural gas prices rose in 2003 by 33 percent, resulting in a $40 million increase in revenues when compared to the same period in 2002. The overall decline in natural gas volumes was due to the sales of production properties in New Mexico, Utah and western Canada as well as normal production declines and mechanical failures in certain producing wells. Our oil, condensate and liquids revenues, including the impact of hedges, were $1 million higher in the third quarter of 2003. Our 2003 oil, condensate and liquids volumes decreased by six percent, resulting in a $3 million decrease in revenues versus the same period in 2002. Realized oil, condensate and liquids prices rose in 2003 by 11 percent, resulting in a $4 million increase in revenues when compared to the same period in 2002. The declines in volumes were primarily due to the property sales, production declines and mechanical failures mentioned above.

Transportation and net product costs for the quarter ended September 30, 2003, were $7 million lower than the same period in 2002 primarily due to a lower percentage of gas volumes subject to transportation fees and lower fees incurred in 2003 to meet minimum payments on pipeline agreements.

Operating expenses for the quarter ended September 30, 2003, were $6 million lower than the same period in 2002 primarily due to lower oilfield service costs of $3 million, as a result of asset dispositions which reduced labor and production processing fees, lower severance and other taxes of $6 million and lower general and administrative costs of $5 million. Partially offsetting these decreases were higher depletion expense of $9 million which was comprised of a $39 million increase due to higher depreciation, depletion and amortization (DD&A) rates in 2003 and costs of $2 million related to the accretion of our liability for asset retirement obligations in 2003, partially offset by a $32 million decrease due to lower production volumes in 2003. The higher depletion rate resulted from increased finding and development costs coupled with a lower reserve base due to asset sales.

Nine Months Ended 2003 Compared to Nine Months Ended 2002

Operating revenues for the nine months ended September 30, 2003, were $234 million lower than the same period in 2002. Our natural gas revenues, including the impact of hedges, were $231 million lower in 2003. Our 2003 natural gas production volumes decreased by 42 percent, resulting in a $347 million decrease in revenues versus the same period in 2002. Realized natural gas prices rose in 2003 by 24 percent, resulting in a $116 million increase in revenues when compared to the same period in 2002. The decline in natural gas volumes was due to the sales of production properties in Colorado, New Mexico, Utah, Texas, and western Canada as well as normal production declines and mechanical failures on certain producing wells. Our oil, condensate and liquids revenues, including the impact of hedges, were $6 million lower in 2003. Our 2003 oil, condensate and liquids volumes decreased by 28 percent, resulting in a $35 million decrease in revenues versus the same period in 2002. Realized oil, condensate and liquids prices rose in 2003 by 33 percent, resulting in a $29 million increase in revenues when compared to the same period in 2002. The declines in volumes were primarily due to the property sales, production declines and mechanical failures mentioned above.

Transportation and net product costs for the nine months ended September 30, 2003, were $6 million lower than the same period in 2002 primarily due to a lower percentage of gas volumes subject to transportation fees and lower fees incurred in 2003 to meet minimum payments on pipeline agreements.

Operating expenses for the nine months ended September 30, 2003, were $297 million lower than the same period in 2002 primarily due to a 2002 non-cash full cost ceiling test charge of $243 million for our international properties in Canada, Brazil and Australia. Also contributing to the decrease were lower oilfield service costs of $36 million, primarily due to asset dispositions which resulted in lower labor and production processing fees, a $5 million gain in 2003 on the sales of non-full cost pool assets and lower general and administrative costs of $8 million. Further decreasing expenses were lower depletion expenses of $24 million, comprised of a $129 million decrease due to lower production volumes in 2003, partially offset by a $97 million increase due to higher DD&A rates in 2003 and costs of $8 million related to the accretion of our liability for asset retirement obligations. The higher depletion rate in 2003 resulted from increased finding and development costs coupled with a lower reserve base due to asset sales. Partially offsetting the decreases in expenses were intangible asset impairments of $14 million in 2003 on non-full cost assets in Canada and higher severance and other taxes of $5 million in 2003. The increase in severance taxes was primarily due to tax credits taken in 2002 for qualified natural gas wells.

Field Services

Our Field Services segment conducts our midstream activities. In the second quarter of 2003, we sold our midstream assets in the Mid-Continent region. These assets primarily included 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. These assets generated EBIT of approximately $10 million during the year ended December 31, 2002. Our remaining assets now consist primarily of our processing facilities in the south Louisiana and Rocky Mountain regions.

As a result of our asset sales and the resulting decline in our gathering and processing activities, our EBIT has decreased significantly. For a further discussion of the business activities of our Field Services segment, see our Current Report on Form 8-K dated September 23, 2003. Results of our Field Services segment operations were as follows for the periods ended September 30:

Field Services Segment Results	Quarter Ended September 30, 2003	Quarter Ended September 30, 2002	Nine Months Ended September 30, 2003	Nine Months Ended September 30, 2002
	(In millions, except volumes and prices)			
Gathering and processing gross margins[1]	$ 17	$ 28	$ 60	$ 84
Operating expenses	(9)	(16)	(14)	(40)
Operating income	8	12	46	44
Other expense	(1)	(48)	(80)	(48)
EBIT	$ 7	$ (36)	$ (34)	$ (4)
Volumes and prices				
Gathering				
Volumes (BBtu/d)	23	574	116	619
Prices ($/MMBtu)	$ 0.09	$ 0.12	$ 0.15	$ 0.13
Processing				
Volumes (inlet BBtu/d)	1,550	1,716	1,667	1,746
Prices ($/MMBtu)	$ 0.10	$ 0.13	$ 0.11	$ 0.12

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

Third Quarter 2003 Compared to Third Quarter 2002

Total gross margins for the quarter ended September 30, 2003, were $11 million lower than the same period in 2002 primarily due to lower margins as a result of the sales of our Natural Buttes and Ouray natural gas gathering systems in December 2002, Wyoming gathering assets in January 2003, and Mid-Continent gathering and processing assets in June 2003.

Operating expenses for the quarter ended September 30, 2003, were $7 million lower than the same period in 2002 primarily due to the asset sales discussed above.

Other expenses for the quarter ended September 30, 2003, were $47 million lower than the same period in 2002 due to a loss recorded in September 2002 related to the sale of our investment in the Aux Sable natural gas liquids plant.

Nine Months Ended 2003 Compared to Nine Months Ended 2002

Total gross margins for the nine months ended September 30, 2003, were $24 million lower than the same period in 2002. The decrease was primarily due to lower margins of $28 million as a result of the sales of our Dragon Trail processing plant in May 2002, Natural Buttes and Ouray natural gas gathering systems in December 2002, Wyoming gathering assets in January 2003, and Mid-Continent gathering and processing assets in June 2003. Partially offsetting this decrease was a $7 million increase in our south Louisiana processing margins due to higher natural gas liquids prices and change in contract terms.

Operating expenses for the nine months ended September 30, 2003, were $26 million lower than the same period in 2002 primarily due to the asset sales discussed above, resulting in lower operating costs and depreciation expenses of $16 million and a net gain of $19 million from the sale of our Mid-Continent midstream assets in the second quarter of 2003. The decreases were partially offset by a $10 million gain in the second quarter of 2002 from the sale of our Dragon Trail processing plant.

Other expenses for the nine months ended September 30, 2003, were $32 million higher than the same period in 2002 due to $80 million in impairment charges on our Dauphin Island Gathering Partners and Mobile Bay Processing Partners investments. The impairment was recorded based on an expected loss from the anticipated sale of our interests in these investments. Partially offsetting the increase was a loss of $47 million recorded in September 2002 related to the sale of our investment in the Aux Sable natural gas liquids plant.

Merchant Energy

Our Merchant Energy segment primarily consists of global power operations, which includes the ownership and operation of domestic and international power generating facilities and our power restructuring activities. Our Current Report on Form 8-K dated September 23, 2003, includes a description of the various power activities included in our Merchant Energy segment. Historically, our Merchant Energy segment also included our petroleum markets operations, but in June 2003, El Paso's Board of Directors approved the sale of substantially all of these operations. As a result, our petroleum markets operations were reclassified as discontinued operations for all periods presented. For a further discussion of our discontinued petroleum markets operations, see Item 1, Note 6. Merchant Energy's operating results and an analysis of those results for the periods ended September 30 are presented below:

Merchant Energy Segment Results	Quarter Ended September 30, 2003	Quarter Ended September 30, 2002	Nine Months Ended September 30, 2003	Nine Months Ended September 30, 2002
	(In millions)			
Gross margin	$ 35	$ 51	$ 121	$ 626
Operating expenses	(44)	(37)	(101)	(141)
Operating income (loss)	(9)	14	20	485
Other income (expense)	(4)	22	26	(79)
EBIT	$ (13)	$ 36	$ 46	$ 406

In 2002, we restructured the power contracts of several of our power plants, which resulted in significant gains in 2002 and reduced operating revenues and expenses for those plants in 2003 because the plants were converted to merchant plants, operating only when economically feasible. Upon restructuring, we began recognizing changes in the fair value of the restructured derivative contracts in our earnings rather than when the power under the contracts was delivered. Going forward, the changes in fair value of these restructured derivative contracts may cause volatility in our future operating results. These restructured derivative contracts are significantly impacted by changes in interest rates, which is more fully explained in Item 3, Quantitative and Qualitative Disclosures About Market Risk. Due to a decline in El Paso's credit rating in late 2002 and early 2003, we no longer pursue additional power contract restructuring activities and are pursuing the sale of our domestic power operations.

As we execute sales of our domestic power plants, results of operations will increase or decrease from our current results based on the earnings and timing of the potential sale of the respective plant or investment. In addition to the earnings impact of the operations sold, a commitment to sell power plants in the future may trigger an event that could result in impairment charges in future periods.

Third Quarter 2003 Compared to Third Quarter 2002

Gross margin for our power activities consists of revenues from our power plants and the net initial gains and losses incurred in connection with the restructuring of power contracts, as well as the subsequent revenues, cost of electricity purchases and changes in fair value of these contracts. The cost of fuel in the power generation process is included in operating expenses. For the quarter ended September 30, 2003, our gross margin was $16 million lower than the same period in 2002. The decrease was primarily due to a $12 million decrease in revenues from our Eagle Point merchant facility due to lower volumes of power generated during 2003. The lower volumes resulted from mechanical difficulties with one of the turbines used by the facility in

2003 and the decision to not fully operate the power plant on a merchant basis due to lower demand and margins in 2003.

Operating expenses for the quarter ended September 30, 2003, were $7 million higher than the same period in 2002, primarily due to an impairment of a crude oil pipeline of $10 million in 2003 due to a decline in the expected reserves of a crude oil field from which the pipeline is used to transport crude oil to a common gathering point. Also contributing to the increase was $6 million of costs to convert the Eagle Point merchant facility to allow for operation in a merchant capacity in 2003. Offsetting these increases were $9 million of decreases primarily due to lower operating expenses from our Eagle Point merchant facility resulting from lower volumes of power generated during 2003. The lower volumes resulted from mechanical difficulties with one of the turbines used by the facility in 2003 and the decision to not fully operate the power plant on a merchant basis due to lower demand and margins in 2003.

Other income (expense) for the quarter ended September 30, 2003, decreased by $26 million compared to the same period in 2002. This decrease was primarily due to a $13 million decrease in equity earnings in 2003 of one of our equity investments that experienced a decline in the fair value of its derivative fuel supply contracts. Also contributing to this decrease was $6 million of legal fees related to arbitration proceedings on two of our Asian equity investments in 2003.

Nine Months Ended 2003 Compared to Nine Months Ended 2002

For the nine months ended September 30, 2003, our gross margin was $505 million lower than the same period in 2002. The decrease was primarily due to $486 million of gains on power contract restructurings for our Eagle Point and Nejapa power plants that we completed in 2002. Contributing to the decrease in gross margin was a decrease of $77 million in 2003 power generation revenues primarily due to mechanical difficulties with one of the turbines used by our Eagle Point merchant facility in 2003 and the decision to not fully operate the power plant on a merchant basis due to lower demand and margins in 2003. Partially offsetting these decreases was a $72 million increase in gross margin resulting from an increase in the fair values of our power restructuring contracts in 2003 compared to a decrease in their fair values in 2002. This increase resulted primarily from income accretion for the nine months in 2003 compared to six months in 2002 since the power contracts were restructured in the first quarter of 2002.

Operating expenses for the nine months ended September 30, 2003, were $40 million lower than the same period in 2002. The decrease was primarily due to a $33 million decrease in operating costs of our Eagle Point merchant facility resulting from the decision to not fully operate the power plant on a merchant basis due to lower demand and margins in 2003. Partially offsetting the decrease was an impairment charge associated with a crude oil pipeline of $10 million in 2003 due to a decline in the expected reserves of a crude oil field from which the pipeline is used to transport crude oil to a common gathering point.

Other income (expense) for the nine months ended September 30, 2003 was $105 million higher than the same period in 2002. This increase is primarily due to a $90 million contract termination fee we paid in 2002 to our petroleum markets operations associated with the termination of a steam contract between our Eagle Point power facility and the Eagle Point refinery (which is included in our petroleum markets operations reflected in discontinued operations). Also contributing to the increase was $50 million of minority owner's interest primarily on the power contract restructurings for our Eagle Point and Nejapa power plants that we completed in 2002. Partially offsetting this decrease was $12 million of legal fees related to arbitration proceedings on two of our Asian equity investments in 2003.

Interest and Debt Expense

Interest and debt expense for the quarter and nine months ended September 30, 2003, was $16 million and $24 million lower than the same periods in 2002. Below is an analysis of our interest expense for the periods ended September 30:

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2003	2002	2003	2002
	(In millions)			
Long-term debt, including current maturities	$106	$121	$307	$317
Other interest	1	3	5	23
Capitalized interest	(4)	(5)	(10)	(14)
Total interest and debt expense	$103	$119	$302	$326

Third Quarter 2003 Compared to Third Quarter 2002

Interest expense on long-term debt for the quarter ended September 30, 2003, was $15 million lower than the same period in 2002 primarily due to a $29 million reduction in interest due to the retirement of approximately $1.3 billion of long-term debt in 2002 and 2003 with an average interest rate of 6.90%. This decrease was partially offset by a $7 million increase in interest related to ANR's March 2003 issuance of $300 million senior notes. In addition, we experienced $6 million of interest due to the reclassification of $300 million of preferred securities as long-term debt in the third quarter as a result of the adoption of a new accounting standard SFAS No. 150. See Note 1 for a discussion of this accounting change.

Other interest for the quarter ended September 30, 2003, was $2 million lower than the same period in 2002 primarily due to the retirement of our other financing obligations.

Capitalized interest for the quarter ended September 30, 2003, was $1 million lower than the same period in 2002 primarily due to lower average interest rates in the third quarter 2003 than the same period in 2002.

Nine Months Ended 2003 Compared to Nine Months Ended 2002

Interest expense on long-term debt for the nine months ended September 30, 2003, was $10 million lower than the same period in 2002 primarily due to a $67 million decrease in interest due to the retirement of approximately $1.7 billion of long-term debt in 2002 and 2003 with an average interest rate of 6.50%. This decrease was partially offset by a $37 million increase in interest from Utility Contract Funding borrowed in July 2002 and Mohawk River Funding IV debt borrowed in June 2002. These debts were borrowed for ongoing capital projects, investment programs and operating requirements. Also offsetting the decrease was $15 million of additional interest related to ANR's March 2003 issuance of $300 million senior notes and $6 million of interest due to the reclassification of $300 million of preferred securities as a result of the adoption of SFAS No. 150.

Other interest for the nine months ended September 30, 2003, was $18 million lower than the same period in 2002. The decrease was primarily due to a $12 million reduction in interest resulting from the retirement of other financing obligations and a $4 million decrease due to the reduction in our power and trading activities in 2003.

Capitalized interest for the nine months ended September 30, 2003, was $4 million lower than the same period in 2002 primarily due to lower average interest rates in 2003 than in 2002.

Affiliated Interest Expense, Net

Affiliated interest expense, net for the quarter and nine months ended September 30, 2003, was $11 million and $25 million, or $8 million and $16 million higher than the same periods in 2002. The increase was primarily due to higher average advances payable to El Paso under our cash management program in 2003, partially offset by higher average short-term interest rates. The average advances payable balance for the third quarter increased from $1,126 million in 2002 to $2,113 million in 2003 and the average advances payable balance for the nine months increased from $1,089 million in 2002 to $2,129 million in 2003. The average short-term interest rates for the third quarter increased from 1.8% in 2002 to 1.9% in 2003 and the average short-term interest rate for the nine months decreased from 1.9% in 2002 to 1.6% in 2003.

Distributions on Preferred Interests of Consolidated Subsidiaries

Distributions on preferred interests of consolidated subsidiaries for the quarter and nine months ended September 30, 2003, were $6 million and $13 million lower than the same periods in 2002 primarily due to the redemptions of our preferred interests in consolidated subsidiaries, including those related to El Paso Oil & Gas Associates, Coastal Limited Ventures and El Paso Oil & Gas Resources and due to the reclassification of our Coastal Finance I mandatorily redeemable preferred securities to long-term debt as a result of the adoption of SFAS No. 150. The decreases were also due to lower interest rates in 2003. Our preferred distributions are based on variable short-term rates, which were lower on average in 2003 than the same periods in 2002.

Income Taxes

Income taxes from continuing operations and our effective tax rates for the periods ended September 30 were as follows:

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2003	2002	2003	2002
	(In millions, except for rates)			
Income taxes	$ (5)	$22	$84	$189
Effective tax rate	(24)%	37%	31%	33%

Our effective tax rates were different than the statutory tax rate of 35 percent in 2003 primarily due to:

- state income taxes, net of federal income tax benefit;
- foreign income taxed at different rates; and
- abandonment of foreign investments.

Our effective tax rates were different than the statutory tax rate of 35 percent in 2002 primarily due to:

- state income taxes, net of federal income tax benefit; and
- foreign income taxed at different rates.

During the quarters and nine months ended September 30, 2003 and 2002, we experienced a number of events that have impacted our overall effective tax rate on continuing operations. These events included the treatment of our coal and petroleum markets operations as discontinued operations (in which income taxes are apportioned between continuing and discontinued operations) and the abandonment of several foreign investments. These events, coupled with relatively low pretax income in continuing operations, have caused, and may continue to cause, variations in our effective tax rate.

Discontinued Operations

During the nine months ended September 30, 2003, our after-tax loss from discontinued operations was $1,187 million. During this period, we recorded pre-tax charges of $1,366 million related to impairments of long-lived assets and investments triggered by our decision to sell substantially all of our petroleum markets business, approximately $929 million of which related to the impairment of our Aruba refinery and approximately $252 million of which related to the impairment of our Eagle Point refinery.

We also incurred $23 million of net losses on our refinery operations during the nine months ended September 30, 2003 which included losses from our Aruba refinery of $73 million and earnings from our Eagle Point refinery of $55 million. The Aruba refinery losses primarily related to lower throughput due to significant turnaround maintenance activities during the third quarter of 2003. We expect our Eagle Point refinery's volumes to be lower in the fourth quarter of 2003 due to scheduled turnaround maintenance activities.

The income tax benefit related to discontinued operations for the nine months ended September 30, 2003, was $229 million resulting in an effective tax rate for discontinued operations of 16 percent. This effective rate was different than the statutory rate of 35 percent primarily due to state income taxes and foreign income taxed at different rates.

In the second quarter of 2003, we entered into a product offtake agreement with Vitol S.A. Inc., for the sale of a number of the products produced at our Aruba refinery. As a result of this contract, Vitol became the single largest customer of our Aruba refinery, purchasing approximately 75 percent of the products produced at that plant. The agreement is for one year with two one-year extensions at Vitol's option. We have the right to terminate the agreement when the refinery is sold.

Commitments and Contingencies

See Item 1, Note 12, which is incorporated herein by reference.

New Accounting Pronouncements Issued But Not Yet Adopted

See Item 1, Note 15, which is incorporated herein by reference.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

This report contains or incorporates by reference forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. Where any forward-looking statement includes a statement of the assumptions or bases underlying the forward-looking statement, we caution that, while we believe these assumptions or bases to be reasonable and in good faith, assumed facts or bases almost always vary from the actual results, and the differences between assumed facts or bases and actual results can be material, depending upon the circumstances. Where, in any forward-looking statement, we or our management express an expectation or belief as to future results, that expectation or belief is expressed in good faith and is believed to have a reasonable basis. We cannot assure you, however, that the statement of expectation or belief will result or be achieved or accomplished. The words "believe," "expect," "estimate," "anticipate" and similar expressions will generally identify forward-looking statements.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

This information updates, and you should read it in conjunction with, information disclosed in our Current Report on Form 8-K dated September 23, 2003, in addition to the information presented in Items 1 and 2 of this Quarterly Report on Form 10-Q.

There are no material changes in our quantitative and qualitative disclosures about market risks from those reported in our Current Report on Form 8-K dated September 23, 2003, except as presented below:

Market Risk

We are exposed to a variety of market risks in the normal course of our business activities, including commodity price, foreign exchange and interest rate risks. We measure risks on the derivative and non-derivative contracts in our portfolio on a daily basis using a Value-at-Risk model. We measure our Value-at-Risk using a historical simulation technique, and we prepare it based on a confidence level of 95 percent and a one-day holding period. This Value-at-Risk was $3 million and $7 million as of September 30, 2003 and December 31, 2002, and represents our potential one-day unfavorable impact on the fair values of our contracts. These contracts primarily relate to our petroleum markets business, which is included in discontinued operations. As we liquidate our portfolio, our Value-at-Risk may vary from period to period.

Interest Rate Risk

As of September 30, 2003, our non-trading derivatives not designated as hedges (see Item 1, Note 8) were comprised of $947 million of long-term power purchase and power supply contracts. These contracts are associated with our power contract restructuring activities and are valued using estimated future market power prices and a discount rate that considers the appropriate U.S. Treasury rate plus a credit spread specific to the contract's counterparty. We make adjustments to this discount rate when we believe that market changes in the rates result in changes in value that can be realized. Since September 30, 2002, in order to provide for market risk, we have not reflected the increase in the value that would result from decreases in U.S. Treasury rates because we believe the resulting increase in fair value of these non-trading derivatives could not be realized in a current transaction between willing parties. Had we reflected the actual U.S. Treasury yields as of September 30, 2003 in our valuation, the value of our non-trading derivatives would have been higher by approximately $102 million. Our exposure to changes in interest rates and credit spreads has not been included in our Value-at-Risk calculation since these risks are managed separately from the other derivative positions included in our Value-at-Risk model. As of September 30, 2003, a ten percent increase or decrease in the discount rate used to value these positions would result in a change in the fair value of these derivative contracts of $(38) million and $40 million.

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 over financial reporting (Internal Controls) as of the end of the period covered by 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 property 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 CGP Company'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. 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. Therefore, 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. Our Disclosure Controls and Internal Controls are designed to provide such reasonable assurances of achieving our desired control objectives, and our principal executive officer and principal financial officer have concluded that our Disclosure Controls and Internal Controls are effective in achieving that level of reasonable assurance.

No Significant Changes in Internal Controls. We have sought to determine whether there were any "significant deficiencies" or "material weaknesses" in El Paso CGP Company's Internal Controls, or whether the company had identified any acts of fraud involving personnel who have a significant role in El Paso CGP Company'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 there has not been any change in Internal Controls during the period covered by this Quarterly Report that has materially affected, or is reasonably likely to materially affect, Internal Controls.

Effectiveness of Disclosure Controls. Based on the controls evaluation, our principal executive officer and principal financial officer have concluded that the Disclosure Controls are effective to ensure that material information relating to El Paso CGP Company and its consolidated subsidiaries is made known to management, including the principal executive officer and principal financial officer, on a timely basis.

Officer Certification. 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 as Exhibits to this Quarterly Report.

PART II — OTHER INFORMATION

Item 1. Legal Proceedings.

See Part I, Item 1, Note 12, 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.

Exhibit Number	Description
*31.A	Certification of Chief Executive Officer pursuant to § 302 of the Sarbanes-Oxley Act of 2002.
*31.B	Certification of Chief Financial Officer pursuant to § 302 of the Sarbanes-Oxley Act of 2002.
*32.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.
*32.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
September 23, 2003	Revised financial information presented in our Annual Report on Form 10-K for the year ended December 31, 2002, to segregate our petroleum markets business as a discontinued operation.

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 CGP COMPANY

Date: November 12, 2003

/s/ D. DWIGHT SCOTT

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

Date: November 12, 2003

/s/ JEFFREY I. BEASON

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