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, 2002

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 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 14, 2002: 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.

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,	
	2002	2001	2002	2001
Operating revenues	$1,648	$1,951	$6,153	$7,162
Operating expenses				
Cost of products and services	1,084	1,073	3,542	4,246
Operation and maintenance	335	403	996	1,319
Merger-related costs and asset impairments	—	15	—	997
Ceiling test charges	—	115	243	115
Depreciation, depletion and amortization	151	178	514	520
Taxes, other than income taxes	23	41	75	153
	1,593	1,825	5,370	7,350
Operating income (loss)	55	126	783	(188)
Earnings from unconsolidated affiliates	42	51	126	156
Minority interest in consolidated subsidiaries	3	—	(50)	—
Net loss on sale of assets	(29)	(5)	(6)	(3)
Other income	30	21	154	70
Other expenses	(1)	(8)	(99)	(20)
Non-affiliated interest and debt expense	(119)	(103)	(339)	(339)
Affiliated interest expense, net	(4)	(12)	(9)	(34)
Returns on preferred interests of consolidated subsidiaries	(7)	(11)	(28)	(37)
Income (loss) before income taxes	(30)	59	532	(395)
Income taxes	(10)	20	174	(31)
Income (loss) from continuing operations before extraordinary items and cumulative effect of accounting changes	(20)	39	358	(364)
Discontinued operations, net of income taxes	(36)	1	(122)	(1)
Extraordinary items, net of income taxes	—	(4)	—	(11)
Cumulative effect of accounting changes, net of income taxes	—	—	14	—
Net income (loss)	$ (56)	$ 36	$ 250	$ (376)

See accompanying notes.

EL PASO CGP COMPANY

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

	September 30, 2002	December 31, 2001
ASSETS		
Current assets		
Cash and cash equivalents	$ 148	$ 141
Accounts and notes receivable, net		
Customer	1,899	1,786
Affiliates	409	546
Other	225	210
Inventory	707	683
Assets from price risk management activities	187	425
Other	685	396
Total current assets	4,260	4,187
Property, plant and equipment, at cost		
Natural gas and oil properties, at full cost	7,329	7,765
Pipelines	6,472	6,541
Refining, crude oil and chemical facilities	2,505	2,425
Power facilities	479	288
Gathering and processing systems	389	428
Other	58	60
	17,232	17,507
Less accumulated depreciation, depletion and amortization	6,107	5,790
Total property, plant and equipment, net	11,125	11,717
Other assets		
Investments in unconsolidated affiliates	1,758	1,882
Assets from price risk management activities	1,097	267
Other	788	1,013
	3,643	3,162
Total assets	$19,028	$19,066

See accompanying notes.

EL PASO CGP COMPANY

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

	September 30, 2002	December 31, 2001
LIABILITIES AND STOCKHOLDER'S EQUITY		
Current liabilities		
Accounts payable		
Trade	$ 1,988	$ 1,832
Affiliates	2,387	1,336
Other	267	359
Short-term borrowings (including current maturities of long-term debt and other financing obligations)	572	1,410
Liabilities from price risk management activities	261	213
Income taxes payable	387	198
Other	488	432
Total current liabilities	6,350	5,780
Long-term debt and other financing obligations, less current maturities	5,044	5,107
Other liabilities		
Liabilities from price risk management activities	125	1
Deferred income taxes	1,575	1,735
Other	435	579
	2,135	2,315
Commitments and contingencies		
Securities of subsidiaries		
Preferred interests of consolidated subsidiaries	575	892
Minority interests in consolidated subsidiaries	67	2
	642	894
Stockholder's equity		
Common stock, par value $1 per share; authorized and issued 1,000 shares	—	—
Additional paid-in capital	1,305	1,305
Retained earnings	3,635	3,385
Accumulated other comprehensive income (loss)	(83)	280
Total stockholder's equity	4,857	4,970
Total liabilities and stockholder's equity	$19,028	$19,066

See accompanying notes.

EL PASO CGP COMPANY

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

	Nine Months Ended September 30,	
	2002	2001
Cash flows from operating activities		
Net income (loss)	$ 250	$ (376)
Less loss from discontinued operations, net of income taxes	(122)	(1)
Net income (loss) from continuing operations	372	(375)
Adjustments to reconcile net income (loss) to net cash from operating activities		
Non-cash gains from trading and power activities	(426)	—
Non-cash portion of merger-related costs, asset impairments and changes in estimates	—	1,190
Depreciation, depletion and amortization	514	520
Ceiling test charges	243	115
Undistributed earnings of unconsolidated affiliates	(18)	(71)
Deferred income tax expense (benefit)	(44)	11
Extraordinary items	—	6
Cumulative effect of accounting changes	(23)	—
Other non-cash income items	(40)	43
Working capital changes	530	(389)
Non-working capital changes and other	(217)	332
Cash provided by continuing operations	891	1,382
Cash provided by (used in) discontinued operations	98	(4)
Net cash provided by operating activities	989	1,378
Cash flows from investing activities		
Additions to property, plant and equipment	(1,157)	(1,487)
Additions to investments	(178)	(253)
Net proceeds from the sale of assets	937	115
Net proceeds from the sale of investments	35	336
Cash deposited in escrow	(96)	—
Return of cash deposited in escrow	93	—
Repayment of notes receivable from unconsolidated affiliates	121	213
Cash paid for acquisitions, net of cash acquired	45	(232)
Other	(23)	—
Cash used in continuing operations	(223)	(1,308)
Cash used in investing activities by discontinued operations	(10)	(35)
Net cash used in investing activities	(233)	(1,343)
Cash flows from financing activities		
Net repayments under commercial paper and short-term credit facilities	(30)	(795)
Issuances of common stock	—	2
Net proceeds from the issuance of long-term debt and other financing obligations	876	250
Payments to retire long-term debt and other financing obligations	(1,524)	(578)
Payments to minority interest holders	(160)	—
Payments to preferred interest holders	(350)	—
Dividends paid	—	(13)
Net proceeds from the issuance of minority interest in subsidiaries	33	139
Net change in notes payable to unconsolidated affiliates	(55)	—
Net change in affiliated advances payable	471	1,093
Contributions from (distributions to) discontinued operations	78	(47)
Other	—	7
Cash provided by (used in) continuing operations	(661)	58
Cash provided by (used in) financing activities by discontinued operations	(78)	47
Net cash provided by (used in) financing activities	(739)	105
Increase in cash and cash equivalents	17	140
Less increase in cash and cash equivalents related to discontinued operations	10	8
Increase in cash and cash equivalents from continuing operations	7	132
Cash and cash equivalents		
Beginning of period	141	57
End of period	$ 148	$ 189

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,	
	2002	2001	2002	2001
Net income (loss)	$ (56)	$ 36	$ 250	$(376)
Foreign currency translation adjustments	(36)	(10)	(13)	(8)
Unrealized net gains (losses) from cash flow hedging activity				
Cumulative-effect transition adjustment (net of tax of $248)	—	—	—	(459)
Unrealized mark-to-market gains (losses) arising during period (net of tax of $15 and $128 in 2002 and $134 and $415 in 2001)	(17)	253	(212)	773
Reclassification adjustments for changes in initial value to settlement date (net of tax of $13 and $78 in 2002 and $37 and $75 in 2001)	(17)	(69)	(138)	137
Other comprehensive income (loss)	(70)	174	(363)	443
Comprehensive income (loss)	$(126)	$210	$(113)	$ 67

See accompanying notes.

EL PASO CGP COMPANY

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

1. Basis of Presentation

We prepared this Quarterly Report on Form 10-Q under the rules and regulations of the United States Securities and Exchange Commission. Because this is an interim period filing presented using a condensed format, it does not include all of the disclosures required by generally accepted accounting principles. You should read it along with our 2001 Annual Report on Form 10-K which includes a summary of our significant accounting policies and other disclosures. The financial statements as of September 30, 2002, and for the quarters and nine months ended September 30, 2002 and 2001, are unaudited. We derived the balance sheet as of December 31, 2001, from the audited balance sheet filed in our Form 10-K. In our opinion, we have made all adjustments, all of which are of a normal, recurring nature (except for the items discussed below and in Notes 3 through 7), to fairly present our interim period results. Due to the seasonal nature of our businesses, information for interim periods may not indicate the results of operations for the entire year. In addition, prior period information presented in these financial statements includes reclassifications which were made to conform to the current period presentation. These reclassifications have no effect on our previously reported net income or stockholder's equity.

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

Goodwill and Other Intangible Assets

Our intangible assets consist of goodwill resulting from acquisitions and other intangible assets. On January 1, 2002, we adopted Statement of Financial Accounting Standards (SFAS) No. 141, *Business Combinations*, and SFAS No. 142, *Goodwill and Other Intangible Assets*. These standards require that we recognize goodwill separately from other intangible assets. In addition, goodwill and intangibles that have lives that are indefinite are no longer amortized. Rather, goodwill is periodically tested for impairment, at least on an annual basis, or whenever an event occurs that indicates that an impairment may have occurred. Prior to adoption of these standards, we amortized goodwill and other intangibles using the straight-line method over periods ranging from 5 to 40 years. As a result of our adoption of these standards on January 1, 2002, we stopped amortizing goodwill.

We completed our initial periodic impairment tests of goodwill during the first quarter of 2002, and concluded we did not have any adjustment to our goodwill amounts. The net carrying amounts and changes in the net carrying amounts of goodwill for each of our segments for the nine month period ended September 30, 2002, are as follows:

	Pipelines	Production	Merchant Energy	Field Services	Corporate & Other	Total
			(In millions)			
Balances as of January 1, 2002	$408	$ 61	$ —	$ 15	$ 5	$489
Other changes	—	1	—	—	—	1
Balances as of September 30, 2002	$408	$ 62	$ —	$ 15	$ 5	$490

Our other intangible assets consist of capitalized development costs, software licensing agreements, customer lists and other miscellaneous intangible assets. We amortize all intangible assets on a straight-line basis over their estimated useful life. The following are the gross carrying amounts and accumulated amortization of our other intangible assets as of:

	September 30, 2002	December 31, 2001
	(In millions)	
Intangible assets subject to amortization	$323	$ 69
Accumulated amortization	(287)	(26)
	$ 36	$ 43

Amortization expense of our intangible assets that were subject to amortization was $3 million and $12 million for the quarter and nine months ended September 30, 2002. For the quarter and nine months ended September 30, 2001, amortization of all intangible assets, including goodwill, was $8 million and $21 million. Based on the current amount of intangible assets subject to amortization, our estimated amortization expense for each of the next five years are as follows: $1 million for each of 2003, 2004 and 2005 and less than $1 million for both 2006 and 2007. These amounts may vary as a result of future acquisitions and dispositions.

The following table presents our income (loss) from continuing operations before extraordinary items and cumulative effect of accounting changes, net income (loss) for the quarter and nine months ended September 30, 2001, as if goodwill had not been amortized during those periods, compared with the income (loss) from continuing operations before extraordinary items and cumulative effect of accounting changes and net income (loss) we reported for the quarter and nine months ended September 30, 2002:

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2002	2001	2002	2001
	(In millions)			
Reported income (loss) from continuing operations before extraordinary items and cumulative effect of accounting changes	$ (20)	$ 39	$ 358	$ (364)
Amortization of goodwill and indefinite-lived intangibles	—	3	—	13
Adjusted income (loss) from continuing operations before extraordinary items and cumulative effect of accounting changes	$ (20)	$ 42	$ 358	$ (351)
Net income (loss):				
Reported net income (loss)	$ (56)	$ 36	$ 250	$ (376)
Amortization of goodwill and indefinite-lived intangibles	—	3	—	13
Adjusted net income (loss)	$ (56)	$ 39	$ 250	$ (363)

Asset Impairments

On January 1, 2002, we adopted SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*. SFAS No. 144 changed the accounting requirements related to when an asset qualifies as held for sale or as a discontinued operation and the way in which we evaluate impairments of assets. It also changes accounting for discontinued operations such that we can no longer accrue future estimated operating losses in these operations. We applied SFAS No. 144 in accounting for our coal mining operations and the proposed sale of pipelines and midstream assets, which met all of the requirements. Our coal mining business was treated as discontinued operations in the second quarter of 2002, and the assets were treated as assets held for sale in the third quarter of 2002. See Notes 2 and 6 for further information.

Early Extinguishment of Debt

During the third quarter of 2002, we adopted the provisions of SFAS No. 145, *Rescission of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement No. 13, and Technical Corrections.* SFAS No. 145 requires that we evaluate any gains or losses incurred when we retire debt early to determine whether they are extraordinary in nature or whether they should be included in income from continuing operations in the income statement. In the third quarter of 2002, we retired debt totaling $10 million, which resulted in a gain of $1 million. Because we believe that we will continue to retire debt in the near term, we reported these gains as income from continuing operations, as part of other income.

Price Risk Management Activities

In the second quarter of 2002, we adopted Derivatives Implementation Group (DIG) Issue No. C-15, *Scope Exceptions: Normal Purchases and Sales Exception for Certain Option-Type Contracts and Forward Contracts in Electricity*. DIG Issue No. C-15 requires that if an electric power contract includes terms that are based upon market factors that are not related to the actual costs to generate the power, the contract is a derivative that must be recorded at its fair value. An example is a power sales contract at a natural gas-fired power plant that has pricing indexed to the price of coal. Our adoption of these rules did not have a material effect on our financial statements. The accounting for electric power contracts as derivatives was not clearly addressed when SFAS No. 133, *Accounting for Derivatives and Hedging Activities*, was adopted in January 2001. DIG Issue No. C-15 and other DIG Issues have attempted to resolve inconsistencies in the accounting for power contracts, and we believe the rules will continue to evolve. It is possible that our accounting for these contracts may change as new guidance is issued and existing rules are applied and interpreted.

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*. DIG Issue No. C-16 requires that if a fixed-price fuel supply contract allows the buyer to purchase, at their option, additional quantities at a fixed price, the contract is a derivative that must be recorded at its fair value. One of our unconsolidated affiliates, the Midland Cogeneration Venture Limited Partnership, recognized a gain on one fuel supply contract upon adoption of these new rules, 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.

During the second quarter of 2002, we adopted a consensus decision reached by the Emerging Issues Task Force (EITF) in EITF Issue No. 02-3, *Issues Related to Accounting for Contracts Involved in Energy Trading and Risk Management Activities.* The consensus required that all mark-to-market gains and losses related to energy trading contracts, including physical settlements, be recorded on a net basis in the income statement instead of being reported on a gross basis as revenues for physically settled sales and expenses for physically settled purchases. As a result of adoption, we now report our trading activity on a net basis as a component of revenues. We also applied this guidance to all prior periods, which had no impact on previously reported net income or stockholder's equity. For the quarter and nine months ended September 30, 2001, we reclassified costs of $4.4 billion and $12.8 billion to operating revenues. In October 2002, the EITF reached several additional decisions regarding accounting for energy trading contracts. See Note 15 for a discussion of these decisions.

Accounting for Power Restructuring Activities. Our Merchant Energy segment's power restructuring activities involve amending or terminating a power plant's existing power purchase contract to eliminate the requirement that the plant provide power from its own generation to the regulated utility and replacing that requirement with the ability to provide power to the utility from the wholesale power market. Prior to a restructuring, the power plant and its related power purchase contract are generally accounted for at their historical cost, which is either the cost of construction or, if acquired, the acquisition cost. Revenues and expenses prior to restructuring are, in most cases, accounted for on an accrual basis as power is generated and sold to the utility. Following a restructuring, the accounting treatment for the power purchase agreement can change if the restructured contract meets the definition of a derivative and is therefore required to be marked to its fair value under SFAS No. 133. In the period the restructuring is completed, the book value of the restructured contract (if it meets the definition of a derivative) is adjusted to its fair value, with any change reflected in income. Since the power plant no longer has the exclusive right to provide power under the original, dedicated power purchase contract, it operates as a peaking merchant plant, generating power only when it is economical to do so. Because of this significant change in its use, in most cases the book value of the plant is reduced to its fair value through a charge to earnings. These changes require us to terminate or amend any related fuel supply and steam agreements associated with the operations of the facility.

We completed the Eagle Point Cogeneration restructuring in the first quarter of 2002. The restructured power contract is presented in our balance sheet as an asset from price risk management activities, and the associated power supply agreement is presented as a liability from price risk management activities. In our income statement we present, as operating revenues, the original adjustment that occurs when the contract is marked to fair value as a derivative, as well as subsequent changes in the value of the contract. Costs associated with the restructuring activity, including adjustments to the underlying power plant's book value and any related intangible assets, contract termination fees and closing costs, are recorded in our income statement as cost of products and services. Power restructuring activities can also involve contract terminations that result in a cash payment by the utility to cancel the underlying power contract. We employed the principles of our power restructuring business in reaching a settlement in the first quarter of 2002 of the dispute under our Nejapa power contract which included a cash payment to us. We recorded this payment as operating revenue. For the nine months ended September 30, 2002, we recognized total revenues from power restructuring and contract termination activities of $1,030 million and total costs of $606 million. On the date the restructuring transactions were completed, revenues recorded were $973 million and costs were $551 million. Revenues and costs recorded after the initial completion date, which consisted of changes in value of the restructured contracts and those associated with performing under the contracts, were $57 million and $55 million.

2. Divestitures

In December 2001, El Paso Corporation (El Paso), our parent, announced a plan to strengthen its balance sheet in order to improve its liquidity in response to changes in market conditions in our industry. A key component of that plan was the identification and sale of assets. Through the date of this report, we have completed or announced the following asset sales:

Completed Asset Sales

Disposal Period	Disposed Asset	Net Proceeds (In millions)	Gain	Segment
February 2002	CIG Trailblazer Gas Company, L.L.C., which owned pipeline expansion rights	$ 12	$11	Pipelines
March 2002	Natural gas and oil properties located in east and south Texas	$512	—[1]	Production
May 2002	Dragon Trail processing plant	$ 65	$10	Field Services
May 2002	Natural gas and oil properties located in Colorado	$212	—[1]	Production
June 2002	Natural gas and oil properties located in southeast Texas	$ 48	—[1]	Production
July 2002	Natural gas and oil production properties in Texas, Kansas and Oklahoma and their related contracts	$112	—[1]	Pipelines
September 2002	50 percent equity interest in a petroleum products terminal	$ 31	$15	Merchant Energy

(1) We did not recognize gains or losses on the natural gas and oil production properties sold since they were not significant in terms of the total costs or reserves in our full cost pool of properties.

Announced Asset Sales

In July 2002, our parent entered into a letter of intent with El Paso Energy Partners, L.P., an affiliate, to sell our Typhoon offshore natural gas and oil gathering pipelines, as well as our natural gas liquids (NGL) pipelines and a related fractionation facility in Texas. The Typhoon pipelines consist of a 35-mile, 20-inch natural gas pipeline and a 16-mile, 12-inch oil pipeline originating on the Chevron/BHP "Typhoon" platform in the Green Canyon area of the Gulf of Mexico. The NGL assets consist of over 500 miles of NGL pipelines and a related fractionation facility in Texas.

This proposed sale was approved by both our parent's and El Paso Energy Partners' Boards of Directors, which included the approval of El Paso Energy Partners' special conflicts committee, which is comprised of independent members of the partnership's Board of Directors. In addition, our parent received a fairness opinion from Deutsche Bank stating that the proceeds to be received from El Paso Energy Partners for all of the assets being sold was fair in relation to the value of the related assets. This transaction is subject to customary regulatory reviews and approvals, as well as the execution of definitive agreements, the completion of due diligence and the partnership's ability to successfully obtain financing for the transaction. The closing of this sale is expected to occur by the end of 2002.

These assets have been classified as assets held for sale in our balance sheet as of September 30, 2002, and we stopped depreciating them beginning July 2002. The total assets being sold include net property, plant and equipment of approximately $109 million. We reclassified these assets as other current assets as of September 30, 2002, since we plan to sell them in the next twelve months. Based upon our anticipated proceeds, we do not expect to realize a material gain or loss from this sale.

The sale of our federally regulated natural gas gathering system located in the Panhandle Field of Texas for $19 million is subject to final closing pending a FERC abandonment order.

The proposed sale of our 14.4 percent equity interest in the Canadian and United States segments of the Alliance Pipeline and our Aux Sable natural gas liquids plant, and related entities for approximately $165 million is subject to customary regulatory reviews and approvals and the execution of definitive agreements. Based on the estimated sales price, we recorded a loss for the quarter ended September 30, 2002, of approximately $47 million. The loss relates to our investment in Aux Sable and is included in our Field Services segment.

In November 2002, El Paso entered into an agreement with Westport Resources Corporation to sell our Natural Buttes and Ouray natural gas gathering facilities. These assets include 240 miles of natural gas gathering pipelines with approximately 200 MMcf/d of capacity. The transaction is expected to close by year end.

In November 2002, we announced an agreement to sell substantially all of our reserves and properties in Virginia, West Virginia and Kentucky. We expect to complete the sale in the fourth quarter of 2002. These properties are in our financial statements as discontinued operations. See Note 6 for further discussion.

3. Merger-Related Costs and Asset Impairments

The following tables summarize our merger-related costs and asset impairments for the periods ended September 30:

	Quarter Ended September 30, 2001					
	Pipelines	Production	Merchant Energy	Field Services	Corp. and Other	Total
			(In millions)			
Merger-related costs						
Merger-related asset impairments	$ 5	$ —	$—	$—	$—	$ 5
Employee severance, retention and transition costs	1	—	(1)	—	—	—
Other	—	—	—	8	2	10
Total merger-related costs	$ 6	$ —	$(1)	$ 8	$ 2	$15

	Nine Months Ended September 30, 2001					
	Pipelines	Production	Merchant Energy	Field Services	Corp. and Other	Total
			(In millions)			
Merger-related costs						
Employee severance, retention and transition costs	$ 76	$ 7	$ 17	$ 2	$481	$583
Business and operational integration costs	95	15	—	—	54	164
Merger-related asset impairments	16	16	116	—	—	148
Other	30	23	10	11	19	93
Asset impairments	—	—	9	—	—	9
Total merger-related costs and asset impairments	$217	$61	$152	$13	$554	$997

Merger-Related Costs

Employee severance, retention and transition costs include direct payments to, and benefit costs for, severed employees and early retirees that occurred as a result of our merger-related workforce reduction and consolidation. Following our merger with El Paso, we completed an employee restructuring across all of our operating segments, resulting in the reduction of 3,200 full-time positions through a combination of early retirements and terminations. Employee severance costs include actual severance payments and costs for pension and post-retirement benefits settled and curtailed under existing benefit plans as a result of these restructurings. Retention charges include payments to employees who were retained following the mergers and payments to employees to satisfy contractual obligations. Transition costs relate to costs to relocate employees and costs for severed and retired employees arising after their severance date to transition their jobs into the ongoing workforce.

Employee severance, retention, and transition costs for the nine months ended September 30, 2001, were approximately $583 million which included pension and post-retirement benefits of $214 million which were accrued at the merger date and will be paid over the applicable benefit periods of the terminated and retired employees. All other costs were expensed as incurred and have been paid. Also included in the 2001 employee severance, retention and transition costs was a charge of $278 million resulting from the issuance of approximately 4 million shares of El Paso common stock on the date of the our merger in exchange for the fair value of our employees' and directors' stock options and restricted stock. A total of 339 employees and 11 directors received these shares.

Business and operational integration costs include charges to consolidate facilities and operations of our business segments. Total charges for the nine months ended September 30, 2001 were $164 million. The charges include incremental fees under software and seismic license agreements of $15 million, which were recorded in our Production segment, and approximately $149 million in estimated lease-related costs to relocate our pipeline operations from Detroit, Michigan to Houston, Texas incurred in both our Pipeline and Corporate segments. These charges were accrued at the time we completed our relocations and closed these offices. The amounts accrued will be paid over the term of the applicable non-cancelable lease agreements. All other costs were expensed as incurred.

Merger-related asset impairments for the nine months ended September 30, 2001, were $148 million which relate to write-offs or write-downs of capitalized costs for duplicate systems, redundant facilities and assets whose value was impaired as a result of decisions on the strategic direction of our combined operations following our merger with El Paso. Our Merchant Energy segment incurred $116 million in asset impairment charges primarily related to the write-down of $37 million for the Oyster Creek refining facility which was shut down following the merger, $35 million for the Kansas refinery which was closed as part of the sale of retail outlets in the Midwest, $20 million for capitalized development costs primarily associated with our petroleum operations and $24 million for other assets. Included in our Production segment was a $16 million charge to write-down Australian and Indonesian international assets since the decision was made following the merger to no longer actively seek future exploratory drilling opportunities in these areas. Additional charges of $16 million were incurred in the Pipelines segment primarily to write-off the investments in the Whitecap and the Supply Link projects, both of which were pipeline projects discontinued following the merger. All of these assets have either had their operations suspended or continue to be held for use. The charges taken were based on a comparison of the cost of the assets to their estimated fair value to the ongoing operations based on our changes in operating strategy.

Other costs for the nine months ended September 30, 2001, were $93 million which include payments made in satisfaction of obligations arising from the approval of our merger with El Paso and other miscellaneous charges. These items were expensed in the period in which they were incurred.

Asset Impairments

During the nine months ended September 30, 2001, we incurred an asset impairment charge of approximately $9 million resulting from unrecoverable capitalized costs of Merchant Energy's Corpus Christi refinery.

4. Ceiling Test Charges

Under the full cost method of accounting for natural gas and oil production properties, we perform quarterly ceiling tests to evaluate whether the carrying value of natural gas and oil production 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. As of September 30, 2002, using period-end daily posted natural gas and oil prices, our capitalized costs exceeded the ceiling limit. Due to an increase in daily posted prices subsequent to September 30, 2002, no ceiling test charges were recorded in our income statement for the third quarter 2002, based upon the daily posted natural 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 natural gas and oil prices as of September 30, 2002, we would have incurred a ceiling test charge of $96 million for our domestic full cost pool.

During 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 was charged during the second quarter. The write-down includes $226 million for our Canadian full cost pool, $10 million for our Brazilian full cost pool and $7 million for other international production operations. The charge for the Canadian full cost pool primarily resulted from a low daily posted price for natural gas at June 30, 2002, which was approximately $1.43 per million British thermal unit. For the nine months ended September 30, 2001, we recorded ceiling test charges of $115 million, including $87 million for our Canadian full cost pool and $28 million for our Brazilian full cost pool.

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. Had the impact of our hedges not been included in calculating our ceiling test charges, we would have incurred an additional third quarter 2002 charge of $29 million, or a total charge of $125 million for the nine months ended September 30, 2002, and $830 million at September 30, 2001, relating to our domestic full cost pool. The charges for our international cost pools would not have materially changed since we do not significantly hedge our international production activities.

5. Changes in Accounting Estimates

Included in our operation and maintenance costs for the quarter and nine months ended September 30, 2001, were approximately $113 million and $316 million in costs related to changes in accounting estimates. The costs for the nine months ended September 30, 2001, consist of $229 million in additional environmental remediation liabilities, $48 million in additional accrued legal obligations and a $39 million charge to reduce the value of our spare parts inventories to reflect changes in the usability of these parts in our worldwide operations. The change in our estimated environmental remediation liabilities was due to a number of events, including $109 million resulting from the sale of a majority of our retail gas stations,

$31 million related to our closure of our Gulf Coast Chemical and Midwest refining operations, $10 million associated with the lease of our Corpus Christi refinery to Valero, and $79 million associated with conforming our methods of environmental identification, assessment and remediation strategies and processes to El Paso's historical practices following our merger with El Paso. The change in estimate of our legal obligations was a result of a review process to assess our legal exposures, strategies and plans following our merger with El Paso. Finally, the charge related to our spare parts inventories was primarily the result of several events that occurred as part of and following our merger with El Paso, including the consolidation of numerous operating locations, the sale of a majority of our retail gas stations, the shutdown of our Midwest refining operations and the lease of our Corpus Christi refinery. These charges were also a direct result of a fire at our Aruba refinery whereby a portion of the plant was rebuilt following the fire rendering many of these parts unusable. Also impacting these amounts was the evaluation of the operating standards, strategies and plans of our combined company following the merger. Our changes in accounting estimates have reduced our after-tax earnings by approximately $76 million and $209 million for the quarter and nine months ended September 30, 2001.

6. Discontinued Operations

In June 2002, our parent's Board of Directors authorized the sale of our coal mining operations. These operations, which have historically been included in our Merchant Energy segment, consist of fifteen active underground and two surface mines located in Kentucky, Virginia and West Virginia. Following the authorization of the sale by our parent's Board of Directors, we compared the carrying value of the underlying assets to our estimated sales proceeds, net of estimated selling costs, based on bids received in the sales process in the second and third quarters of 2002. Because this carrying value was higher than our estimated net sales proceeds, we recorded impairment charges of $148 million in the second quarter of 2002 and $37 million in the third quarter of 2002.

We expect that our coal mining business will be sold in two parts: (1) coal reserves and properties and (2) coal mining operations. In November 2002, we announced an agreement to sell substantially all of our reserves and properties in West Virginia, Virginia and Kentucky to an affiliate of Natural Resources Partners, L.P. for $69 million. We expect to complete the sale, subject to regulatory reviews and approvals, in the fourth quarter of 2002. We expect to enter into agreements to sell the coal mining operations within the next six months.

Our coal mining operations have been classified as discontinued operations in our financial statements for all periods presented. In addition, we reclassified all of the assets and liabilities of our coal mining operations as of September 30, 2002, to other current assets and liabilities because we plan to sell them in the next twelve months. The summarized financial results of discontinued operations are as follows:

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2002	2001	2002	2001
	(In millions)			
Operating Results:				
Revenues	$ 75	$ 64	$ 243	$ 206
Costs and expenses	(95)	(64)	(259)	(210)
Asset impairments	(37)	—	(185)	—
Other income, net	—	1	6	3
Income (loss) before income taxes	(57)	1	(195)	(1)
Income tax benefit	21	—	73	—
Income (loss) from discontinued operations, net of income taxes	$(36)	$ 1	$(122)	$ (1)

	September 30, 2002	December 31, 2001
	(In millions)	
Financial Position Data:		
Assets of discontinued operations		
Accounts receivable	$ 26	$ 35
Inventory	12	11
Property, plant and equipment, net	101	301
Other	15	5
Total assets	$154	$352
Liabilities of discontinued operations		
Accounts payable and other	$ 24	$ 37
Environmental remediation reserve	15	—
Total liabilities	$ 39	$ 37

7. Extraordinary Items

Under a Federal Trade Commission order, as a result of our January 2001 merger with El Paso, we sold our Gulfstream pipeline project, our 50 percent interest in the Stingray and U-T Offshore pipeline systems, and our investments in the Empire State and Iroquois pipeline systems. For the nine months ended September 30, 2001, net proceeds from these sales were approximately $184 million. We recognized extraordinary net losses of approximately $11 million, net of income taxes of approximately $5 million, including a third quarter 2001 charge of $4 million to record additional estimated income taxes on these sales.

8. Financial Instruments and Price Risk Management Activities

The following table summarizes the carrying value of our trading and non-trading price risk management assets and liabilities as of September 30, 2002 and December 31, 2001:

	September 30, 2002	December 31, 2001
	(In millions)	
Net assets (liabilities)		
Trading contracts(1)(3)	$ 12	$(23)
Non-trading contracts(2)(3)		
Derivatives designated as hedges	(77)	501
Other derivatives	963	—
Net assets from price risk management activities(4)	$898	$478

(1) Trading contracts represent those that qualify for accounting under EITF Issue No. 98-10, *Accounting for Contracts Involved in Energy Trading and Risk Management Activities.* See Note 15 for a discussion of changes in the accounting rules that will impact our accounting for energy-trading contracts.

(2) Non-trading contracts include hedges related to our natural gas and oil producing activities and derivatives from our power contract restructuring activities.

(3) We do not recognize gains on the fair value of trading or non-trading positions beyond ten years unless there is clearly demonstrated liquidity in a specific market.

(4) 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 derivative contracts related to the power restructuring activities of our consolidated subsidiaries. Of this amount, $872 million relates to a power restructuring that occurred during the first quarter of 2002 at our Eagle Point Cogeneration power plant, and $91 million relates to a 2001 power restructuring at our Capitol District Energy Center Cogeneration Associates plant.

The fair value of the derivatives related to our power restructuring activities is determined based on the expected cash receipts and payments under the contracts using future power prices compared to the contractual prices under these contracts. We discount these cash flows at an interest rate commensurate with the term of each contract and the credit risk of each contract's counterparty. We make adjustments to this discount rate when we believe that market changes in the rates result in changes in fair values that can be realized. We consider whether changes in the rates are the result of changes in the capital markets, or are the result of sustained economic changes. During the third quarter, treasury rates declined. We did not adjust our discount rate for this decline in treasury rates since this decrease, combined with the significant uncertainties in the capital markets, did not result in an increased fair value that we believe could have been realized in the market. We also adjust our valuations for factors such as market liquidity, market price correlation and model risk, as needed. Future power prices are based on the forward pricing curve of the appropriate power delivery and receipt points in the applicable power market. This forward pricing curve is derived from a combination of actual prices observed in the applicable market, price quotes from brokers and extrapolation models that rely on actively quoted prices and historical information. The timing of cash receipts and payments are based on the expected timing of power delivered under these contracts. The fair value of our derivatives is updated each period based on changes in actual and projected market prices, fluctuations in the credit ratings of our counterparties, significant changes in interest rates, and changes to the assumed timing of deliveries.

In May 2002, we announced a plan to reduce the volumes of natural gas that we have hedged for our Production segment, and we removed the hedging designation on derivatives that had a fair value loss of $56 million at September 30, 2002. This amount, net of income taxes of $20 million, is reflected in accumulated other comprehensive income and will be reclassified to income as the original hedged transactions are settled through 2004. Of the net loss of $36 million in accumulated other comprehensive income, we estimate that unrealized losses of $2 million, net of income taxes, related to these derivatives will be reclassified to income over the next twelve months.

9. Inventory

Our inventory consisted of the following:

	September 30, 2002	December 31, 2001
	(In millions)	
Refined products, crude oil and chemicals	$595	$576
Materials and supplies and other	112	107
	$707	$683

10. Debt and Other Credit Facilities

At December 31, 2001, our weighted average interest rate on our short-term credit facilities was 2.4%, and there were no amounts outstanding under these facilities at September 30, 2002. We had the following short-term borrowings and other financing obligations:

	September 30, 2002	December 31, 2001
	(In millions)	
Current maturities of long-term debt and other financing obligations	$569	$1,310
Notes payable to unconsolidated affiliates	1	67
Short-term credit facility	—	30
Other	2	3
	$572	$1,410

Our significant borrowing and repayment activities during 2002 are presented below. These activities do not include repayments on our short-term financing instruments with an original maturity of three months or less, including our short-term credit facilities.

Issuances

Date	Company	Type	Interest Rate	Principal	Net Proceeds	Due Date
				(In millions)		
2002						
April	Mohawk River Funding IV[1]	Senior secured notes	7.75%	$ 92	$ 90	2008
July	Utility Contract Funding[1]	Senior secured notes	7.944%	829	786	2016

Retirements

Date	Company	Type	Interest Rate	Principal	Net Payments	Due Date
				(In millions)		
2002						
March	El Paso CGP	Long-term debt	Variable	$400	$400	2002
June	El Paso CGP	Crude oil prepayment	Variable	300	300	2002
June	El Paso CGP	Long-term debt	Variable	90	90	2002
Jan.-June	Coastal Oil & Gas	Natural gas production payment	LIBOR + 0.372%	216	216	2002-2005
July	El Paso CGP	Long-term debt	Variable	55	55	2002
August	El Paso CGP[2]	Long-term debt	6.20%	10	9	2004
August	El Paso CGP	Long-term debt	6.625%	460	25[3]	2004
June-Aug.	El Paso CGP	Long-term debt	Variable	51	51	2010-2028
September	El Paso CGP	Long-term debt	8.125%	250	250	2002
Jan.-Sept.	El Paso CGP	Long-term debt	Variable	106	106	2002
Jan.-Sept.	Various	Long-term debt	Various	22	22	2002
Oct.-Nov.	El Paso CGP	Crude oil prepayment	Various	133	133	2002
November	El Paso CGP	Long-term debt	Variable	60	60	2002

(1) These notes are collateralized solely by the cash flows and contracts of these consolidated subsidiaries, and are non-recourse to our parent and other affiliated companies. The Mohawk River Funding IV financing relates to our Capitol District Energy Center Cogeneration Associates restructuring transaction, and the Utility Contract Funding financing relates to our Eagle Point Cogeneration restructuring transaction.

(2) These amounts represent a buyback of our bonds in the open market in July and August 2002.

(3) The majority of this debt was exchanged for El Paso common stock. See below for further discussion.

In June 2002, El Paso amended its existing $1 billion 3-year revolving credit and competitive advance facility to permit El Paso to issue up to $500 million in letters of credit and to adjust pricing terms. This facility matures in August 2003. We are a designated borrower under this facility and, as such, are liable for any amounts outstanding under this facility. The interest rate varies based on El Paso's senior unsecured debt rating, and as of September 30, 2002, an initial draw would have had a rate of LIBOR plus 0.625%, plus a 0.25% utilization fee for drawn amounts above 25% of the committed amounts. As of September 30, 2002, there were no borrowings outstanding, and $492 million in letters of credit were issued under the facility.

In September 2002, Moody's lowered our parent's senior unsecured debt rating from Baa2 to Baa3, and in November 2002, Standard and Poor's lowered our parent's senior unsecured debt rating from BBB to BBB-. As a result of these actions, the current interest rate on an initial draw under this credit facility would be at rate of LIBOR plus 0.80%, plus a 0.25% utilization fee for drawn amount above the 25% of the committed amounts.

In August 2002, El Paso issued 12,184,444 shares of its common stock to satisfy purchase contract obligations under our FELINE PRIDES℠ program. In return for the issuance of the stock, we received approximately $25 million in cash from the maturity of a zero coupon bond and the return of $435 million of our existing 6.625% senior debentures due August 2004, that were issued in 1999. The zero coupon bond and the senior debentures had been held as collateral for the purchase contract obligations. The $25 million received from the maturity of the zero coupon bond was used to retire additional senior debentures. Total debt reduction from the issuance of the common stock was approximately $460 million.

We have entered into debt instruments and guaranty agreements that contain covenants such as restrictions on debt levels, restrictions on liens securing debt and guarantees, restrictions on mergers and on sales of assets, capitalization requirements, dividend restrictions and cross-acceleration provisions. A breach of any of these covenants could accelerate the debt or other financial obligations of us and our subsidiaries.

One of the most significant debt covenants is that we must maintain a minimum net worth of $1.2 billion. If breached, the amounts guaranteed by the guaranty agreements could be accelerated. The guaranty agreements also have a $30 million cross-acceleration provision. In addition, we have indentures associated with our public debt that contain $5 million cross-acceleration provisions.

Other Financing Arrangements

During 2000, El Paso formed a series of companies that it refers to as Clydesdale. Clydesdale was formed to provide financing to invest in various capital projects and other assets. A third-party investor contributed cash of $1 billion into Clydesdale in exchange for the preferred securities of one of El Paso's consolidated subsidiaries. Our assets that collateralize the preferred interest include Colorado Interstate Gas Company, and beginning in July 2002, additional natural gas and oil properties.

11. 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.

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 gas working interest owners and gas royalty owners to recover royalties that the plaintiff contends these owners should have received had the volume and heating value of natural gas produced from their properties been differently measured, analyzed, calculated and reported, together with prejudgment and postjudgment interest, punitive damages, treble damages, attorney's fees, costs and expenses, and future injunctive relief to require the defendants to adopt allegedly appropriate gas measurement practices. No monetary relief has been specified in this case. The plaintiffs' motion for class certification has been filed and we have filed our response.

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 five such lawsuits in New York. The plaintiffs seek remediation of their groundwater and prevention of future contamination, compensatory damages for the costs of replacement water and for diminished property values, as well as punitive damages, attorney's fees, court costs, and, in some cases, future medical monitoring. Our costs and legal exposure related to 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, 2002, we had approximately $67 million accrued for all outstanding legal matters.

Environmental Matters

We are subject to extensive 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, 2002, we had accrued approximately $281 million, including approximately $277 million for expected remediation costs and associated onsite, offsite and groundwater technical studies, and approximately $4 million for related environmental legal costs, which we anticipate incurring through 2027. Approximately $15 million of the accrual was related to our discontinued coal mining operations. Our reserves are based on the following estimates of reasonably possible outcomes:

	September 30, 2002	
Sites	**Low**	**High**
	(In millions)	
Operating	$122	$191
Non-operating	132	154
Superfund	7	10

Below is a reconciliation of our accrued liability as of December 31, 2001 to our accrued liability as of September 30, 2002 (in millions):

Balance as of December 31, 2001	$260
Additions/adjustments	27
Payments	(10)
Other changes, net	4
Balance as of September 30, 2002	$281

In addition, we expect to make capital expenditures for environmental matters of approximately $199 million in the aggregate for the years 2002 through 2007. These expenditures primarily relate to compliance with clean air regulations. For the fourth quarter of 2002, we estimate that our total expenditures will be approximately $20 million. In addition, approximately $14 million of this amount will be expended under government directed clean-up plans. The remaining $6 million will be self-directed or in connection with facility closures.

Coastal Eagle Point. From May 1999 to March 2001, our Coastal Eagle Point Oil Company received several Administrative Orders and Notices of Civil Administrative Penalty Assessment from the New Jersey Department of Environmental Protection. All of the assessments are related to alleged noncompliance with the New Jersey Air Pollution Control Act pertaining to excess emissions from the first quarter 1998 through the fourth quarter 2000 reported by our Eagle Point refinery in Westville, New Jersey. The New Jersey Department of Environmental Protection has assessed penalties totaling approximately $1.1 million for these alleged violations. Our Eagle Point refinery has been granted an administrative hearing on issues raised by the assessments and, currently, is in negotiations to settle these assessments. At the agency's request, the administrative law judge put the hearings on inactive status until December 2002 to allow time for settlement discussions.

EPA Fuel Regulations. In February 2002, we received a Notice of Violation from the EPA alleging noncompliance with the EPA's fuel regulations from 1996 to 1998. The notice proposes a penalty of $165,000 for these alleged violations. We have settled with the EPA for $120,000. The settlement agreement also includes an additional $52,500 penalty for a self-disclosed fuels noncompliance. We expect to pay the total settlement of $172,500 in the fourth quarter of 2002.

CERCLA Matters. We have been designated and 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 22 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, 2002, we have estimated our share of the remediation costs at these sites to be between $5 million and $8 million, and we have established reserves which are included in the environmental reserves discussed above. We believe our reserves are adequate for such costs. Since the clean-up costs are estimates and are subject to revision as more information becomes available about the extent of remediation required, and because in some cases we have asserted a defense to any liability, our estimates could change. Moreover, liability under the federal CERCLA statute is joint and several, meaning that we could be required to pay in excess of our pro rata share of remediation costs. Our understanding of the financial strength of other PRPs has been considered, where appropriate, in determining our estimated liabilities.

Rates and Regulatory Matters

Rate Case. In March 2001, Colorado Interstate Gas Company (CIG) filed a rate case with the Federal Energy Regulatory Commission (FERC) proposing increased rates of $9 million annually and new and enhanced services for its customers. CIG received an order from the FERC in late April 2001, which suspended the rates until October 1, 2001, subject to refund, and subject to the outcome of hearing. On September 26, 2001, the FERC rejected two firm services CIG had proposed in its rate filing and required it to reallocate the costs allocated to those two services to existing services. CIG complied with this order and arranged with the affected customers to provide service under existing rate schedules. CIG and its customers entered into a settlement agreement in May 2002 settling all issues in the case. The settlement, which contained a rate increase, was approved by the FERC in August 2002, and became final in September 2002. The settlement obligates CIG to file a rate case to be effective no later than October 1, 2006. CIG will pay approximately $12 million in refunds on November 25, 2002. These refunds are included in other current liabilities, and will not have an adverse effect on our financial position or results of operations.

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

Negotiated Rate NOI. In July 2002, the FERC issued a Notice of Inquiry (NOI) that seeks comments regarding its 1996 policy of permitting pipelines to enter into negotiated rate transactions. Our pipelines have entered into these transactions over the years, and the FERC is now reviewing whether negotiated rates should be capped, whether or not the "recourse rate" (a cost-of-service based rate) continues to safeguard against a pipeline exercising market power, as well as other issues related to negotiated rate programs. On

September 25, 2002, El Paso's pipelines and others filed comments. Reply comments were filed on October 25, 2002. At this time, we cannot predict the outcome of this NOI.

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

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

While the outcome of our outstanding legal matters, environmental matters and rates and regulatory matters cannot be predicted with certainty, based on the information known to date 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. It is possible that new information or future developments could require us to reassess our potential exposure related to these matters. Further, for environmental matters, it is also possible that other developments, such as increasingly strict environmental laws and regulations and claims for damages to property, employees, other persons and the environment resulting from our current or past operations, could result in substantial costs and liabilities in the future. As new information for 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 and on our cash flows in the period the event occurs.

Other Commitments

ANR Independence Pipeline Company, our subsidiary, owns a 33.3 percent interest in Independence Pipeline Company with an investment balance of approximately $18 million. The Management Committee of Independence Pipeline Company voted to dissolve the partnership effective September 30, 2002. Though the pipeline was not constructed, Independence Pipeline Company owns some property and rights of way that were purchased. These assets will be sold over the course of a one-year period and are not expected to amount to more than $1 million. At the end of the third quarter of 2002, we fully reserved for the investment balance.

12. Segment Information

We segregate our business activities into four distinct operating segments: Pipelines, Production, Merchant Energy and Field Services. 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 and marketing strategies. In the second quarter of 2002, we reclassified our historical coal mining operations from our Merchant Energy segment to discontinued operations in our financial statements. All periods were restated to reflect this change.

We use earnings before interest and income taxes (EBIT) to assess the operating results and effectiveness of our business segments. We define EBIT as operating income, adjusted for several items, including: equity earnings from unconsolidated investments, minority interests on consolidated, but less than wholly-owned operating subsidiaries, gains and losses on sales of assets and other miscellaneous non-operating items. Items that are not included in this measure are financing costs, including interest and debt expense and returns on preferred interests of consolidated subsidiaries, income taxes, discontinued operations, extraordinary items and the impact of accounting changes. We believe this measurement is useful to our investors because it allows them to evaluate the effectiveness of our businesses and operations and our investments from an operational perspective, exclusive of the costs to finance those activities and exclusive of income taxes, neither of which are directly relevant to the efficiency of those operations. This measurement may not be comparable to measurements used by other companies and should not be used as a substitute for net income or other performance measures such as operating cash flow. The following are our segment results as of and for the periods ended September 30:

	Quarter Ended September 30, 2002					
	Pipelines	Production	Merchant Energy	Field Services	Corporate & Other[1]	Total
	(In millions)					
Revenues from external customers	$185	$223	$1,130[2]	$110	$ —	$1,648
Intersegment revenues	8	22	(13)[2]	21	(38)	—
Operating income (loss)	70	69	(96)	13	(1)	55
EBIT	96	71	(52)	(36)	21	100

	Quarter Ended September 30, 2001					
	Pipelines	Production	Merchant Energy	Field Services	Corporate & Other[1]	Total
	(In millions)					
Revenues from external customers	$191	$432	$1,130[2]	$137	$ 61	$1,951
Intersegment revenue	26	27	(5)[2]	13	(61)	—
Merger-related costs	6	—	(1)	8	2	15
Ceiling test charges	—	115	—	—	—	115
Operating income (loss)	65	143	(31)	8	(59)	126
EBIT	86	143	14	7	(65)	185

	Nine Months Ended September 30, 2002					
	Pipelines	Production	Merchant Energy	Field Services	Corporate & Other[1]	Total
	(In millions)					
Revenues from external customers	$652	$888	$4,310[2]	$303	$ —	$6,153
Intersegment revenues	28	76	(69)[2]	42	(77)	—
Ceiling test charges	—	243	—	—	—	243
Operating income (loss)	287	151	337	35	(27)	783
EBIT	388	153	377	(4)	(6)	908

	Nine Months Ended September 30, 2001					
	Pipelines	Production	Merchant Energy	Field Services	Corporate & Other[1]	Total
	(In millions)					
Revenues from external customers	$733	$1,447	$3,924[2]	$703	$ 355	$7,162
Intersegment revenues	60	(84)	242[2]	58	(276)	—
Merger-related costs and asset impairments	217	61	152	13	554	997
Ceiling test charges	—	115	—	—	—	115
Operating income (loss)	71	554	(126)	50	(737)	(188)
EBIT	147	554	1	50	(737)	15

(1) Includes our Corporate, eliminations of intercompany transactions and in 2001, our retail business. Our intersegment revenues, along with our intersegment operating expenses, consist of normal course of business-type transactions between our operating segments. We record an intersegment revenue elimination, which is the only elimination included in the "Other" column, to remove intersegment transactions.

(2) Merchant Energy revenues take into account the adoption of a consesus reached on EITF Issue No. 02-3, which requires us to report all physical sales of energy commodities in our energy trading activities on a net basis as a component of revenue. See Note 1 regarding the adoption of this Issue.

The reconciliations of EBIT to income (loss) from continuing operations before extraordinary items and cumulative effect of accounting changes and total assets are presented below:

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2002	2001	2002	2001
	(In millions)			
Total EBIT	$ 100	$ 185	$ 908	$ 15
Non-affiliated interest and debt expense	(119)	(103)	(339)	(339)
Affiliated interest expense, net	(4)	(12)	(9)	(34)
Returns on preferred interests of consolidated subsidiaries	(7)	(11)	(28)	(37)
Income taxes	10	(20)	(174)	31
Income (loss) from continuing operations before extraordinary items and cumulative effect of accounting changes	$ (20)	$ 39	$ 358	$(364)

	September 30, 2002	December 31, 2001
	(In millions)	
Pipelines	$ 5,303	$ 5,481
Production	5,217	6,534
Merchant Energy	7,285	5,924
Field Services	475	546
Corporate and other	594	229
Total segment assets	18,874	18,714
Discontinued operations	154	352
Total consolidated assets	$19,028	$19,066

13. Investments in Unconsolidated Affiliates and Related Party Transactions

We hold investments in various affiliates which we account for using the equity method of accounting. Summarized financial information for our proportionate share of unconsolidated affiliates below includes affiliates in which we hold an interest of a 50 percent or less, as well as those in which we hold a greater than a 50 percent interest. Our proportional share of the net income of the unconsolidated affiliates in which we hold a greater than 50 percent interest was $9 million and $14 million for the quarters ended, and $27 million and $38 million for the nine months ended September 30, 2002 and 2001.

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2002	2001	2002	2001
	(In millions)			
Operating results data				
Operating revenues	$341	$297	$881	$1,189
Operating expenses	272	221	677	953
Income from continuing operations	50	48	122	140
Net income	50	48	122	140

Consolidation of Investments

As of December 31, 2001, we had investments in Eagle Point Cogeneration Partnership, Capitol District Energy Center Cogeneration Associates and Mohawk River Funding IV. During 2002, we obtained additional rights from our partners in each of these investments and also acquired an additional one percent ownership interest in Capitol District Energy Center Cogeneration Associates and Mohawk River Funding IV. As a result of these actions, we began consolidating these investments effective January 1, 2002.

Related Party Transactions

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

Additionally, 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.

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. As of September 30, 2002 and December 31, 2001, we had borrowed $1,602 million and $908 million. The market rate of interest as of September 30, 2002 was 1.8% and at December 31, 2001, it was 2.1%. In addition, we had a demand note receivable with El Paso of $150 million at September 30, 2002, at an interest rate of 2.3%. At December 31, 2001, the demand note receivable was $120 million at an interest rate of 4.2%.

At September 30, 2002 and December 31, 2001, we had current accounts and notes receivable from related parties of $259 million and $426 million. In addition, we had a non-current note receivable from a related party of $25 million and $27 million included in other non-current assets at September 30, 2002 and at December 31, 2001.

At September 30, 2002 and December 31, 2001, we had other accounts payable to related parties of $785 million and $428 million. In addition, included in short-term borrowings at September 30, 2002 and December 31, 2001, was a current note payable to related parties of $1 million and $67 million.

El Paso Energy Partners

In July 2002, our parent entered into a letter of intent to sell our Typhoon offshore natural gas and oil pipelines as well as our NGL pipelines and a related fractionation facility in Texas to El Paso Energy Partners. See Note 2 for further discussion.

14. Preferred Interests of Consolidated Subsidiaries

El Paso Oil & Gas Resources Preferred Units. In July 2002, we repurchased from UAGC, Inc., an unaffiliated investor, 50,000 units representing all outstanding preferred units in El Paso Oil & Gas Resources Company, L.P., our wholly owned partnership, for $50 million plus accrued and unpaid dividends.

Coastal Limited Ventures Preferred Stock. In July 2002, we repurchased from JPMorgan Chase Bank, an unaffiliated investor, 150,000 shares representing all outstanding preferred stock in Coastal Limited Ventures, Inc., our wholly owned subsidiary, for $15 million plus accrued and unpaid dividends.

Consolidated Partnership. In July 2002, we repurchased the limited partnership interests, from RBCC, Inc., an unaffiliated investor, in El Paso Production Oil and Gas Associates, L.P., a partnership formed with Coastal Limited Ventures, Inc. The payment of approximately $285 million to the unaffiliated investor was equal to the sum of limited partner's outstanding capital plus unpaid priority returns.

15. New Accounting Pronouncements Not Yet Adopted

Accounting for Asset Retirement Obligations

In August 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 143, *Accounting for Asset Retirement Obligations.* This statement requires companies to record a liability for the estimated retirement and removal costs of assets used in their business. The liability is recorded at its fair value, with a corresponding asset which is depreciated over the remaining useful life of the long-lived asset to which the liability relates. An ongoing expense will also be recognized for changes in the value of the liability as a result of the passage of time. The provisions of SFAS No. 143 are effective for fiscal years beginning after June 15, 2002. We are currently assessing and quantifying the asset retirement obligations associated with our long-lived assets. We expect to complete our assessment of these asset retirement obligations and be able to estimate their effect on our financial statements in the fourth quarter of 2002.

Accounting for Costs Associated with Exit or Disposal Activities

In July 2002, the FASB issued SFAS No. 146, *Accounting for Costs Associated with Exit or Disposal Activities.* This statement will require us to recognize costs associated with exit or disposal activities when they are incurred rather than when we commit to an exit or disposal plan. Examples of costs covered by this guidance include lease termination costs, employee severance costs associated with a restructuring, discontinued operations, plant closings or other exit or disposal activities. The statement is effective for fiscal years beginning after December 31, 2002, and will impact any exit or disposal activities we initiate after January 1, 2003.

Accounting for Contracts Involved in Energy Trading and Risk Management Activities

In October 2002, the EITF reached two decisions on EITF Issue No. 02-3, *Issues Related to Accounting for Contracts Involved in Energy Trading and Risk Management Activities.* The first of the two decisions requires that we account for all energy-related contracts that do not qualify as derivatives under SFAS No. 133 using the accrual method of accounting, rather than mark-to-market accounting as was previously required under EITF Issue No. 98-10, *Accounting for Contracts Involved in Energy Trading and Risk Management Activities.* Following our application of this consensus, we will continue to record contracts that are derivatives under SFAS No. 133, at their fair value. The other consensus reached will require that all inventory held by energy-trading operations be accounted for at the lower of its cost or fair value, rather than using mark-to-market accounting as was previously allowed under EITF Issue No. 98-10. We will adopt these decisions during the fourth quarter, and are currently evaluating the effects of these decisions on our price risk management activities.

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 2001 Annual Report on Form 10-K in addition to the financial statements and notes presented in Item 1, Financial Statements, of this Quarterly Report on Form 10-Q.

Included throughout this Management's Discussion and Analysis are terms that are common to our industry:

/d	= per day	MMBtu	= million British thermal units
Bbl	= barrel	Mcf	= thousand cubic feet
BBtu	= billion British thermal units	MMcf	= million cubic feet
BBtue	= billion British thermal unit equivalents	MTons	= thousand tons
MBbls	= thousand barrels	MWh	= megawatt hours

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 is equal to six Mcf of natural gas. Also, when we refer to cubic feet measurements, all measurements are at 14.73 pounds per square inch.

Recent Developments

Since the fourth quarter of 2001, a number of developments in our businesses and industry have impacted our operations and liquidity. These have included:

- The bankruptcy of Enron Corp. and the resulting decline in the energy trading industry; and
- The modification of credit standards by the rating agencies.

As a response to these industry developments, the credit rating agencies, Moody's and Standard and Poor's, re-evaluated the credit ratings of companies involved in energy trading activities, which included our parent and affiliates (and us to a lesser degree) as well as the credit ratings of most of the largest participants in the energy trading industry. Many of these participants have been downgraded to below investment grade and some have experienced significant financial distress. In September 2002, Moody's downgraded our senior unsecured debt from Baa2 to Baa3 (their lowest "investment grade" rating) and has kept us under review for possible further downgrade. In November 2002, Standard and Poor's downgraded our senior unsecured debt from BBB to BBB– (their lowest "investment grade" rating), and we remain on negative credit watch. The rating agencies also lowered our commercial paper rating which resulted in the commercial paper markets currently being unavailable to us at attractive prices.

While these developments do not have an immediate impact on our financial position or results of operations, a further downgrade of our debt securities would result in higher cash requirements to conduct our operations (through cash collateral requirements). If this were to occur we would have less cash available to use for capital expenditures and other purposes, although we do believe we would have sufficient operating resources to fund our ongoing operating activities.

In addition, as a result of the downgrade in the credit rating of several of our customers, and the placement of them on negative credit watch, the credit-worthiness of these companies have been questioned. We have taken actions to mitigate our exposure by requesting these companies provide us with a letter of credit or prepayment as permitted by our pipelines' tariffs. Our pipelines' tariffs permit us to request additional credit assurance from our customers equal to the cost of performing transportation services for either a two or three month period depending on the pipeline. With respect to new construction projects, we have requested credit assurance for longer periods of time from the customers supporting those projects. If these companies file for Chapter 11 bankruptcy protection and our contracts are not assumed by other counterparties, or if the capacity is unavailable for resale, it could have a material adverse effect on our financial position, operating results or cash flows.

Segment Results

Our four segments: Pipelines, Production, Merchant Energy and Field Services are strategic business units that offer a variety of different energy products and services; each requires different technology and marketing strategies. We use earnings before interest expense and income taxes (EBIT) to assess the operating results and effectiveness of our business segments. We define EBIT as operating income, adjusted for several items, including:

- equity earnings from unconsolidated investments;
- minority interests on consolidated, but less than wholly-owned operating subsidiaries;
- gains and losses on sales of assets; and
- other miscellaneous non-operating items.

Items that are not included in this measure are:

- financing costs, including interest and debt expense and returns on preferred interests of consolidated subsidiaries;
- income taxes;
- discontinued operations;
- extraordinary items; and
- the impact of accounting changes.

We believe this measurement is useful to our investors because it allows them to evaluate the effectiveness of our businesses and operations and our investments from an operational perspective, exclusive of the costs to finance those activities and exclusive of income taxes, neither of which are directly relevant to the efficiency of those operations. This measurement may not be comparable to measurements used by other companies and should not be used as a substitute for net income or other performance measures such as operating cash flow. For a further discussion of our individual segments, see Item 1, Financial Statements, Note 12, as well as our 2001 Annual Report on Form 10-K. The segment EBIT results for the periods presented below:

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2002	2001	2002	2001
	(In millions)			
Pipelines	$ 96	$ 86	$388	$ 147
Production	71	143	153	554
Merchant Energy	(52)	14	377	1
Field Services	(36)	7	(4)	50
Segment total	79	250	914	752
Corporate and other	21	(65)	(6)	(737)
Consolidated EBIT	$100	$185	$908	$ 15

Pipelines

Our Pipelines segment includes our interstate natural gas transmission and gas storage operations. Our interstate natural gas transmission systems face varying degrees of competition from other pipelines, as well as alternate energy sources, such as electricity, hydroelectric power, coal and fuel oil.

We are regulated by the Federal Energy Regulatory Commission. The FERC sets the rates we can recover from our customers. These rates are generally a function of our costs of providing services to our customers. As a result, our pipeline results have historically been relatively stable. However, they can be subject to volatility due to factors such as weather, changes in natural gas prices, regulatory actions and the creditworthiness of our customers. In addition, our ability to extend our existing contracts or re-market expiring capacity is dependent on the competitive alternatives, regulatory environment and the supply and demand factors at the relevant extension or expiration dates. While every attempt is made to negotiate contract terms at fully-subscribed quantities and at maximum rates allowed under our tariffs, some of our contracts are discounted to meet competition.

In October 2002, we announced our intent to sell our 14.4 percent interest in the Alliance pipeline system to Enbridge Inc. We expect to complete this sale during the first quarter of 2003. Income earned on our investment in Alliance for the quarter and nine months ended September 30, 2002, was approximately $5 million and $17 million.

Results of our Pipelines segment operations were as follows:

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2002	2001	2002	2001
	(In millions, except volume amounts)			
Operating revenues	$ 193	$ 217	$ 680	$ 793
Operating expenses	(123)	(152)	(393)	(722)
Other income	26	21	101	76
EBIT	$ 96	$ 86	$ 388	$ 147
Throughput volumes (BBtu/d)[(1)]	7,626	7,144	7,666	7,411

(1) Throughput volumes exclude those related to pipeline systems sold in connection with FTC orders related to our merger with El Paso including investments in the Empire State and Iroquois pipelines. Throughput volumes also exclude intrasegment activities.

Third Quarter 2002 Compared to Third Quarter 2001

Operating revenues for the quarter ended September 30, 2002, were $24 million lower than the same period in 2001. A decrease of $29 million resulted from lower revenues from natural gas sales and from gathering and processing activities due to CIG's sale of the Panhandle field and other production properties in July 2002. Also contributing to the decrease were lower transportation revenues of $3 million from lower summer capacity sold under short-term contracts, lower 2002 sales of base gas from abandoned storage fields of $2 million, lower prices on liquids sales of $1 million and lower resales of natural gas purchased from the Dakota gasification facility of $1 million. These decreases were partially offset by higher reservation revenues of $12 million primarily due to our system expansion projects, which were placed in service in 2001.

Operating expenses for the quarter ended September 30, 2002, were $29 million lower than the same period in 2001. A decrease of $14 million was due to CIG's sale of the Panhandle field and other production properties in July 2002. Also contributing to the decrease were $6 million of merger-related costs incurred in 2001 primarily associated with asset impairments, $5 million of lower amortization of goodwill due to the implementation of SFAS No. 142 in 2002 and $3 million of lower ad valorem taxes in 2002. For a discussion of our merger-related costs, see Item 1, Financial Statements, Note 3.

Other income for the quarter ended September 30, 2002, was $5 million higher than the same period in 2001 primarily due to the resolution of uncertainties associated with the sale of our interests in the Gulfstream pipeline project in 2001.

Nine Months Ended 2002 Compared to Nine Months Ended 2001

Operating revenues for the nine months ended September 30, 2002, were $113 million lower than the same period. A decrease of $33 million was due to reduced natural gas and liquids sales due to lower prices in 2002, $29 million decrease from natural gas sales, gathering and processing activities due to CIG's sale of the Panhandle field and other production properties in July 2002 and a $25 million decrease in sale of excess natural gas in 2001. Also contributing to the decrease were $23 million from lower resales of natural gas purchased from the Dakota gasification facility, $16 million lower transportation revenues due to milder weather in 2002 and $4 million lower 2002 sales of base gas from abandoned storage fields. These decreases were partially offset by higher reservation revenues of $26 million primarily due to system expansion projects placed in service in 2001.

Operating expenses for the nine months ended September 30, 2002, were $329 million lower than the same period in 2001 primarily as a result of merger-related costs of $217 million incurred in 2001 to relocate our pipeline operations from Detroit, Michigan to Houston, Texas, costs for employee benefits, severance, retention, transition charges and other miscellaneous charges. Also contributing to the decrease were $25 million from lower gas costs for our system supply purchases and royalties resulting from lower natural gas prices and volumes, $23 million from lower prices on natural gas purchased from the Dakota gasification facility, $18 million of a change in accounting estimate primarily for additional environmental remediation liabilities in 2001, $17 million from lower benefit costs and cost efficiencies following our merger with El Paso, $14 million lower amortization of goodwill due to the implementation of SFAS No. 142 in 2002, $14 million decrease in operating expenses due to CIG's sale of the Panhandle field and other production properties in July 2002, $4 million lower corporate overhead allocations and $2 million lower ad valorem taxes in 2002. These decreases were partially offset by an increase in 2002 in our estimated liabilities of $13 million to assess and remediate our environmental exposure due to an ongoing evaluation of our operating facilities.

Other income for the nine months ended September 30, 2002, was $25 million higher than the same period in 2001. The increase was due to a gain of $11 million on the sale of pipeline expansion rights in February 2002 and $11 million on the resolution of uncertainties associated with the sales of our interests in the Empire State, Iroquois pipeline systems, and our Gulfstream pipeline project in 2001. Also contributing to the increase was higher equity earnings in 2002 of $7 million on our Great Lakes Gas Transmission investment. These increases were partially offset by lower equity earnings of $6 million on Empire State and Iroquois pipeline systems due to the sale of our interests in 2001.

Production

The 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 the lowest total cost level possible.

In the past, our stated goal was to hedge approximately 75 percent of our anticipated current year production, approximately 50 percent of our anticipated succeeding year production and a lesser percentage thereafter. As a component of our strategic repositioning plan in May 2002, we modified this hedging strategy. We now expect to hedge approximately 50 percent or less of our anticipated production for a rolling 12-month forward period. This modification of our hedging strategy will increase our exposure to changes in commodity prices which could result in significant volatility in our reported results of operations, financial position, and cash flows from period to period.

During 2002, we have continued an active onshore and offshore development drilling program to capitalize on our land and seismic holdings. This development drilling is done to take advantage of our large inventory of drilling prospects and to develop our proved undeveloped reserve base. We have also completed asset dispositions in Colorado and Texas as part of our balance sheet enhancement plan. As a result of our asset dispositions, we will likely have a lower reserve base at January 1, 2003 than we did at January 1, 2002. Since our depletion rate is determined under the full cost method of accounting, a lower reserve base coupled with additional capital expenditures in the full cost pool will result in higher depletion expense in future periods. For the fourth quarter of 2002, we expect our unit of production depletion rate to be approximately $1.77 per equivalent unit.

Below are the operating results and an analysis of these results for the periods ended September 30:

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2002	2001	2002	2001
	(In millions)			
Natural gas	$ 208	$ 402	$ 834	$ 1,184
Oil, condensate, and liquids	39	52	125	162
Other	(2)	5	5	17
Total operating revenues	245	459	964	1,363
Transportation and net product costs	(14)	(9)	(39)	(46)
Total operating margin	231	450	925	1,317
Operating expenses[1]	(162)	(307)	(774)	(763)
Other income (expense)	2	—	2	—
EBIT	$ 71	$ 143	$ 153	$ 554
Volumes and prices				
Natural gas				
Volumes (MMcf)	59,625	99,235	208,356	288,363
Average realized prices[2] ($/Mcf)	$ 3.34	$ 3.98	$ 3.87	$ 4.05
Oil, condensate and liquids				
Volumes (MBbls)	1,723	2,263	6,410	6,409
Average realized prices[2] ($/Bbl)	$ 22.24	$ 21.91	$ 18.84	$ 24.50

(1) Include production costs, depletion, depreciation and amortization, ceiling test charges, merger-related costs, change in accounting estimates, corporate overhead, general and administrative expenses and other taxes.

(2) Net of transportation costs.

Third Quarter 2002 Compared to Third Quarter 2001

For the quarter ended September 30, 2002, operating revenues were $214 million lower than the same period in 2001. A 40 percent decrease in natural gas volumes and a 14 percent decrease in natural gas prices, before transportation costs, attributed to $194 million of the decrease in revenues. The decline in natural gas volumes was primarily due to the sale of properties in Texas and Colorado in 2002. In addition, revenues decreased by $13 million due to a 24 percent decrease in oil, condensate and liquids volumes.

Transportation and net product costs for the quarter ended September 30, 2002, were $5 million higher than the same period in 2001 primarily due to costs incurred to meet minimum payments on pipeline agreements.

Operating expenses for the quarter ended September 30, 2002, were $145 million lower than the same period in 2001. Contributing to the decrease in expenses were non-cash full cost ceiling test charges incurred in the third quarter of 2001 totaling $115 million on international properties and lower depletion expenses of $26 million in 2002 due to lower volumes, offsetting higher rates. A $12 million decrease in severance and other taxes in 2002 resulted in an additional decrease to our operating expenses. Offsetting these decreases were higher corporate overhead allocations of $13 million.

Nine Months Ended 2002 Compared to Nine Months Ended 2001

For the nine months ended September 30, 2002, operating revenues were $399 million lower than the same period in 2001. A 28 percent decrease in natural gas volumes and a 2 percent decrease in natural gas prices, before transportation costs, resulted in a $350 million decrease in revenues. The decline in natural gas volumes was primarily due to the sale of properties in Texas and Colorado in 2002. In addition, revenues decreased $37 million due to 23 percent decrease in oil, condensate and liquids prices, before transportation costs.

Transportation and net product costs for the nine months ended September 30, 2002, were $7 million lower than the same period in 2001 primarily due to a higher percentage of gas volumes subject to transportation fees and costs incurred to meet minimum payments on pipeline agreements in 2001.

Operating expenses for the nine months ended September 30, 2002, were $11 million higher than the same period in 2001. Contributing to the increase in expenses were non-cash full cost ceiling test charges totaling $243 million incurred in 2002 for our Canadian full cost pool and other international properties primarily in Brazil and Australia, offset by non-cash full cost ceiling test charges incurred in the third quarter of 2001 totaling $115 million for international properties. Higher corporate overhead allocations of $30 million also contributed to the increase in expenses. Partially offsetting these increases were merger-related costs and other charges of $61 million incurred in 2001 associated with combining operations with El Paso and $10 million of changes in accounting estimates primarily related to a write-down of materials and supplies resulting from the ongoing evaluation of our operating standards recognized in 2001. For a discussion of merger-related costs, see Item 1, Financial Statements, Note 3. For a discussion of write-down of materials and supplies, see Item 1, Financial Statements, Note 5, and for a discussion of our ceiling test charges, see Item 1, Financial Statements, Note 4. In addition, offsetting increased expenses were $67 million of decreased severance and other taxes in 2002, decreased oilfield service costs of $4 million primarily due to lower workovers and production processing and lower depletion expense of $6 million in 2002 due to lower volumes, offsetting higher rates. The severance taxes decreased primarily because of lower natural gas volumes and prices and for tax credits in 2002 for high cost gas wells.

Merchant Energy

Our customer origination and trading activities, as well as our power, refining and chemical activities are conducted through our Merchant Energy segment. As part of the power operations of our Merchant Energy segment, we engage in power contract restructuring activities. As in the case of our Eagle Point Cogeneration restructuring transaction discussed in results of operations below, our restructuring of power plant facilities and related assets are consolidated in our financial statements.

Domestic and International Power

Our domestic and international power business includes the ownership and operation of power generating facilities. In most cases, we partially own our power generating facilities and account for them using the equity method. We also engage in power contract restructuring activities that involve power plants and related assets that are consolidated in our financial statements, as in the case of our Eagle Point Cogeneration restructuring transaction that occurred this year and is discussed in our results of operations below.

Power Contract Restructuring Activities

Many of our domestic power plants have long-term power sales contracts with regulated utilities that were entered into under the Public Utility Regulatory Policies Act of 1978 (PURPA). The power sold to the utility under these PURPA contracts is required to be delivered from a specified power generation plant at power prices that are usually significantly higher than the cost of power in the wholesale power market. Our cost of generating power at these PURPA power plants is typically higher than the cost we would incur by obtaining the power in the wholesale power market, principally because the PURPA power plants are less efficient than newer power generation facilities.

Typically, in a power contract restructuring, the PURPA power sales contract is amended so that the power sold to the utility does not have to be provided from the specific power plant. Because we are able to buy lower cost power in the wholesale power market, we have the ability to reduce the cost paid by the utility, thereby inducing the utility to enter into the power contract restructuring transaction. Following the contract restructuring, the power plant operates on a merchant basis, which means that it is no longer dedicated to one buyer and will operate only when power prices are high enough to make operations economical. In addition, we may assume, and in the case of Eagle Point Cogeneration we did assume, the business and economic risks of supplying power to the utility to satisfy the delivery requirements under the restructured power contract over its term. When we assume this risk, we manage these obligations by entering into transactions to buy power from third parties that mitigate our risk over the life of the contract. These activities are reflected as part of our trading activities and reduce our exposure to changes in power prices from period to period. Power contract restructurings generally result in a higher return in our power generation business because we can deliver reliable power at lower prices than our cost to generate power at these PURPA power plants. In addition, we can use the restructured contracts as collateral to obtain financing at a cost that is comparable to, or lower than, our existing financing costs. The manner in which we account for these activities is discussed in Item 1, Financial Statements, Note 1, of this Form 10-Q.

Power restructuring transactions are often extensively negotiated and can take a significant amount of time to complete. In addition, there are a limited number of facilities to which the restructuring process applies. Our ability to successfully restructure a power plant's contracts and the future financial benefit of that effort is difficult to determine, and may vary significantly from period to period. Since we began these activities in 1999, we have completed five restructuring transactions, including contract terminations, of varying financial significance, and we have additional facilities which we will consider for restructuring in the future.

Petroleum

We own or have interests in oil refineries, chemical production facilities, petroleum terminalling and marketing operations, and blending and packaging operations for lubricants and automotive products. Our refinery operations are cyclical in nature and sensitive to movements in the price of crude oil. We are currently operating in an environment where the differences in the price of our crude oil input and the resulting products output is so narrow that we are experiencing losses in our refinery operations. This has been compounded at our Aruba facility where we have experienced operational difficulties following a fire at the facility last year. We anticipate that our capacity utilization at Aruba will improve in the fourth quarter of 2002 since we have just completed a maintenance turnaround that is expected to bring the facility back up to full capacity. We are also making significant progress in reducing costs at our petroleum facilities, and we believe that conditions are favorable for improved earnings from our petroleum activities in the future. We will continue to rationalize our assets in this business and evaluate our petroleum activities and their strategic fit with our core natural gas business.

Results of Operations

Below are Merchant Energy's operating results and an analysis of these results for the periods ended September 30:

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2002	2001	2002	2001
	(In millions, except volume amounts)			
Trading and refining gross margins	$ 86	$ 190	$ 758	$ 741
Operating and other revenues	54	5	259	41
Operating expenses	(236)	(226)	(680)	(908)
Other income	44	45	40	127
EBIT	$ (52)	$ 14	$ 377	$ 1
Volumes[(1)]				
Physical				
Natural gas (BBtue/d)	—	—	—	3,457
Power (MMWh)	81	164	200	356
Crude oil and refined products (MBbls)	166,961	181,773	530,226	512,220
Financial Settlements (BBtue/d)	1,058	90,593	2,801	78,255

(1) Volumes include those traded over-the-counter in our origination and trading activities, as well as those generated or produced at our consolidated power plants and refineries.

Trading and refining gross margins consist of revenues from commodity trading activities less the cost of commodities sold, the impact of power contract restructuring activities and revenues from refineries and chemical plants, less the costs of feedstocks used in the refining and production processes.

Third Quarter 2002 Compared to Third Quarter 2001

For the quarter ended September 30, 2002, trading and refining gross margins were $104 million lower than the same period in 2001 primarily due to refining margins being lower by $107 million in 2002 resulting from lower spreads between the sales prices of the refined product and the underlying feedstock cost and lower throughput at our Aruba refinery.

Operating and other revenues consist of revenues from domestic and international power generation facilities. For the quarter ended September 30, 2002, operating and other revenues were $49 million higher than the same period in 2001 primarily due to consolidation of domestic and international power facilities in the fourth quarter of 2001 and the first quarter of 2002, which contributed a $45 million increase to operating and other revenues.

Operating expenses for the quarter ended September 30, 2002, were $10 million higher than the same period in 2001. This was due primarily to a $71 million increase in operating expenses, partially offset by a $61 million increase in the third quarter of 2001 primarily for additional estimated environmental remediation liabilities. Contributing to the overall $71 million increase in operating expenses were $23 million of higher expenses resulting from the consolidation of international and domestic power-related entities in the fourth quarter of 2001 and the first quarter of 2002. Besides the consolidation of these entities, operating expenses also reflected a $21 million increase in international employee expenses, training program expenses and unscheduled maintenance expenses at our Aruba refinery in the third quarter of 2002.

Other income for the quarter ended September 30, 2002, was $1 million lower than the same period in 2001. This was primarily due to a $16 million decrease in other income, partially offset by a $15 million gain on sale of our 50 percent interest in a petroleum product terminal in the third quarter of 2002. Contributing to the overall $16 million decrease in other income were $10 million due to lower equity earnings from unconsolidated projects in 2002.

Nine Months Ended 2002 Compared to Nine Months Ended 2001

During the nine months ended September 30, 2002, we completed power restructurings or contract terminations at our Eagle Point Cogeneration and Nejapa power plants. The Eagle Point Cogeneration restructuring transaction, completed in March 2002, was our most significant power restructuring transaction to date.

The Eagle Point restructuring involved several steps. First, we amended the existing PURPA power sales contract with Public Service Electric and Gas (PSEG) to eliminate the requirement that power be delivered specifically from the Eagle Point power plant. This amended contract has fixed prices with stated increases over the 14-year term that range from $85 per MWh to $126 per MWh. We entered into the amended power sales contract through a consolidated subsidiary, Utility Contract Funding, L.L.C. (UCF). UCF was created to hold and execute the terms of the restructured power sales contract, to enter into a supply contract to meet the requirements of the restructured agreement and to monetize the value of these contracts by issuing debt. In keeping with its purpose, UCF entered into a power supply agreement with El Paso Merchant Energy L.P. (EPME), an affiliated company. The terms of the EPME power supply contract were identical to the restructured power contract, with the exception of price, which was set at $37 per MWh over its 14-year term.

For credit enhancement purposes, in anticipation of the financing transaction associated with the restructuring, UCF terminated the EPME supply contract in the second quarter of 2002 and replaced it with a supply contract with a Morgan Stanley affiliate. UCF entered into the Morgan Stanley contract solely for the purpose of reducing the cost of debt UCF would issue.

As a result of the various steps we have taken to accomplish this restructuring, we have been able to improve the expected margin associated with the original PURPA contract by replacing the high-cost of the power generated from the Eagle Point plant, which had averaged over $75 per MWh, with power that we have purchased at a cost of $37 per MWh. We have also shifted the collection and credit risk to a third party over the term of the restructured power sales agreement.

From an accounting standpoint, the actions taken to restructure the contract required us to mark the contract to its fair value under SFAS No. 133. As a result, we recorded non-cash revenue representing the estimated fair value of the derivative contracts of approximately $898 million in our first quarter results. We also amended or terminated other ancillary agreements associated with the cogeneration facility, such as gas supply and transportation agreements, a steam contract and existing financing agreements. In the second quarter, we paid $103 million to the utility to terminate the original PURPA contract. Also included in our first quarter results were a $98 million non-cash charge to adjust the Eagle Point Cogeneration plant to fair value based on its new status as a peaking merchant plant and a non-cash charge of $230 million to write off the book value of the original PURPA contract. Based on these amounts, and including closing and other costs, our first quarter results reflected a net benefit from the Eagle Point Cogeneration restructuring transaction of $348 million. Total operating cash flows from this transaction amounted to approximately $120 million of cash paid to the utility to amend the original contract and other miscellaneous closing costs. In July 2002, UCF completed the restructuring transaction by monetizing the contract with PSEG and issuing $829 million of 7.944% senior notes collateralized solely by the contracts and cash flows of UCF. The proceeds of the monetization are reported as financing cash flow.

We also employed the principles of our power restructuring business in contract termination at our Nejapa power plant in the second quarter of 2002. In March 2002, an arbitration award panel approved the termination of the power purchase agreement between Comision Ejecutiva Hydroelectrica del Rio Lempa and the Nejapa Power Company, one of our consolidated subsidiaries, in exchange for a cash payment of $90 million. The award was finalized and paid to Nejapa in the second quarter of 2002. We recorded, as revenue, a $90 million gain and also recorded $13 million in other expense for the minority owner's share of this gain. We applied the proceeds of the award to retire a portion of Nejapa's debt.

For the nine months ended September 30, 2002, trading and refining gross margins were $17 million higher than the same period in 2001. Our trading and refining margins were affected by our restructuring transactions. We recorded income of $397 million in the first quarter of 2002 related to the Eagle Point Cogeneration power contract restructuring described above. The fair value of our power contract restructurings decreased by $33 million from the initial gain through September 30, 2002. Partially offsetting this net increase in trading and refining gross margins was a $128 million decrease in marine revenues due to lower freight rates, a decrease in vessels owned and on charter, and lower throughput at our marine terminals, and a decrease of $87 million in refining margins resulting from the lease of our Corpus Christi refinery and related assets to Valero in June 2001. When we leased our refinery to Valero, we began including income from the lease as other income. In addition, trading and refining gross margins decreased $87 million from lower spreads between the sales prices of refined product and the underlying feedstock cost and lower throughput at our Eagle Point and Aruba refineries and $37 million due to reimbursement from the insurance company received in 2001 related to the fire at our Aruba facility in April 2001.

For the nine months ended September 30, 2002, operating and other revenues were $218 million higher than the same period in 2001. Contributing to the overall increase were revenues of $147 million from domestic and international power facilities that were consolidated in the fourth quarter of 2001 and the first quarter of 2002 and a $90 million gain from the termination of the Nejapa power contract. Partially offsetting these increases was $20 million from the transfer of power index swaps on our Fulton and Rensselaer power facilities and the sale of a power facility in 2001.

Operating expenses for the nine months ended September 30, 2002, were $228 million lower than the same period in 2001 primarily as a result of decrease of $152 million of merger-related costs and asset impairment recorded in 2001 associated with combining operations with El Paso (see Item 1, Financial Statements, Note 3) and a $133 million increase in estimate in 2001 primarily for additional environmental remediation and legal liabilities. Also contributing to the decrease was a decrease of $54 million in fuel costs used in our refining operations resulting from lower gas prices and the lease of our Corpus Christi refinery and related assets to Valero in June 2001. These decreases were partially offset by $105 million of higher expenses resulting from the consolidation of international and domestic power-related entities in the fourth quarter of 2001 and the first quarter of 2002 and higher international employee expenses, training program expenses and unscheduled maintenance expenses of $29 million at our Aruba refinery in 2002.

Other income for the nine months ended September 30, 2002, was $87 million lower than the same period in 2001. Contributing to the overall decrease was $49 million of minority ownership interest in the initial income earned on our Eagle Point Cogeneration restructuring transaction in the first quarter of 2002, and $13 million of minority owner's interest in the gain on the termination of the Nejapa power contract. Besides the above factors, other income also reflected lower equity earnings of $32 million from unconsolidated projects and foreign currency losses of $4 million in 2002. Partially offsetting these decreases were a $15 million gain on sale of our 50 percent interest in a petroleum product terminal in the third quarter of 2002 and an increase of $7 million in lease income related to the lease of our Corpus Christi refinery to Valero in June 2001.

Field Services

In October 2002, we announced the sale of our 14.4 percent equity interest in the Aux Sable natural gas liquids plant for approximately $10 million. We anticipate a loss on this sale of approximately $47 million and recorded a corresponding writedown of our investment in September 2002. In November 2002, we entered into an agreement to sell our Natural Buttes and Ouray natural gas gathering systems to Westport Resources Corporation for approximately $43 million. We expect to complete the transaction and record a gain on this sale of approximately $29 million in the fourth quarter of 2002. These assets generated EBIT of approximately $8 million during the year ended December 31, 2001.

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

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2002	2001	2002	2001
	(In millions, except volumes and prices)			
Gathering, treating and processing gross margins	$ 28	$ 41	$ 84	$ 126
Operating expenses	(15)	(33)	(49)	(76)
Other income (loss)	(49)	(1)	(39)	—
EBIT	$ (36)	$ 7	$ (4)	$ 50
Volume and prices				
Gathering and treating				
Volumes (BBtu/d)	574	750	619	906
Prices ($/MMBtu)	$ 0.12	$ 0.18	$ 0.13	$ 0.14
Processing				
Volumes (inlet BBtu/d)	1,716	1,964	1,746	1,947
Prices ($/MMBtu)	$ 0.13	$ 0.15	$ 0.12	$ 0.15

Third Quarter 2002 Compared to Third Quarter 2001

Total gross margins for the quarter ended September 30, 2002, were $13 million lower than the same period in 2001. Margins decreased by approximately $8 million primarily due to lower natural gas liquids prices and natural declines in production in 2002, which unfavorably impacted our volumes and margins in the Rockies and south Louisiana regions. Also contributing to the decrease was approximately $3 million related to the sale of the Dragon Trail processing plant in May 2002.

Operating expenses for the quarter ended September 30, 2002, were $18 million lower than the same period in 2001. The decrease was primarily due to a change in our estimated environmental remediation liabilities and other merger-related charges in 2001 of $16 million. Other income for the quarter ended September 30, 2002, was a loss of $49 million attributable to the write down of our investment in the Aux

Sable natural gas liquids plant of approximately $47 million, in anticipation of the loss from our announced sale of this interest.

Nine Months Ended 2002 Compared to Nine Months Ended 2001

Total gross margins for the nine months ended September 30, 2002, were $42 million lower than the same period in 2001. Margins decreased by approximately $34 million primarily due to lower natural gas liquids prices and natural declines in production in 2002, which unfavorably impacted our volumes and margins in the Rockies and south Louisiana regions. Also contributing to the decrease was approximately $4 million related to the sale of the Dragon Trail processing plant in May 2002.

Operating expenses for the nine months ended September 30, 2002, were $27 million lower than the same period in 2001. The decrease was primarily due to merger-related costs of $13 million, a change in our estimated environmental remediation liabilities of $9 million in 2001 and $6 million of lower operating expenses as a result of our cost reduction plan in 2002.

Other income for the nine months ended September 30, 2002, was a loss of $39 million. In September 2002, we wrote down our investment in the Aux Sable natural gas liquids plant by approximately $47 million, in anticipation of the loss from our announced sale of this interest. This loss was partially offset by a $10 million gain from the sale of our Dragon Trail processing plant in 2002.

Corporate and Other

Corporate and other net expenses, which include general and administrative activities as well as other miscellaneous businesses, for the quarter and nine months ended September 30, 2002, were $86 million and $731 million lower than the same periods in 2001. The decrease was primarily due to a charge of $554 million in merger-related costs for the nine months ended September 30, 2001, in connection with our 2001 merger with El Paso. Additional costs for the quarter and nine months ended September 30, 2001, were charges of $42 million and $145 million related to increased estimates of environmental remediation and reductions in fair value of spare parts inventories to reflect changes in usability of spare parts inventories in our corporate operations based on an ongoing evaluation of our operating standards and plans following the merger. Also contributing to the decrease in corporate and other expenses for the quarter and nine months ended September 30, 2002, were losses in 2001 of $13 million and $32 million in our Retail business as a result of the sale of substantially all of our retail gas stations in 2001.

Interest and Debt Expense

Non-affiliated Interest and Debt Expense

Non-affiliated interest and debt expense for the quarter ended September 30, 2002, was $119 million, or $16 million higher than the same period in 2001 primarily due to $22 million increase in interest from Mohawk River Funding IV debt borrowed in June 2002 and the UCF debt borrowed in July 2002. These debts were borrowed for ongoing capital projects, investment programs and operating requirements. These increases were partially offset by $4 million decrease in interest due to lower receivable factoring, $3 million decrease in interest due to repayment of $400 million long-term debt in the first quarter of 2002 as well as the conversion of $435 million FELINE PRIDES℠ to El Paso common stock in August 2002.

Affiliated Interest Expense, Net

Affiliated interest expense, net for the quarter ended September 30, 2002, was $4 million, or $8 million lower than the same period in 2001 due to lower short-term interest rates on decreased average advances from El Paso under our cash management program. The average short-term interest rates for the third quarter decreased from 3.8% in 2001 to 1.8% in 2002.

Affiliated interest expense, net for the nine months ended September 30, 2002, was $9 million, or $25 million lower than the same period in 2001 primarily due to lower short-term interest rates on average advances from El Paso under our cash management program. The average short-term interest rates for the nine months decreased from 4.9% in 2001 to 1.9% in 2002.

Returns on Preferred Interests of Consolidated Subsidiaries

Returns on preferred interests of consolidated subsidiaries for the quarter and nine months ended September 30, 2002, were $7 million and $28 million, or $4 million and $9 million lower than the same periods in 2001, primarily due to a redemption of preferred stock in a consolidated trust in July 2002.

Income Taxes

Income tax benefit for the quarter ended September 30, 2002, was $10 million, resulting in an effective tax rate of 33 percent. Income tax expense for the nine months ended September 30, 2002, was $174 million, resulting in an effective tax rate of 33 percent. Our effective tax rates were different than the statutory rate of 35 percent primarily due to the following:

- state income taxes; and
- foreign income taxed at different rates.

Income tax expense for the quarter ended September 30, 2001, was $20 million resulting in an effective tax rate of 34 percent. Income tax benefit for the nine months ended September 30, 2001, was $31 million, resulting in an effective tax rate of 8 percent. The nine months ended September 30, 2001 benefit included $105 million of tax expense associated with non-deductible merger charges and changes in our estimates of additional tax liabilities. The majority of these estimated additional liabilities were paid in 2001 and are being contested by us. The effective tax rate excluding these charges for the nine months ended September 30, 2001 was 34 percent. Other differences between the effective tax rates and the statutory tax rate of 35 percent were primarily due to the following:

- state income taxes; and
- foreign income taxed at different rates.

Commitments and Contingencies

See Item 1, Financial Statements, Note 11, which is incorporated herein by reference.

New Accounting Pronouncements Not Yet Adopted

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

CAUTIONARY STATEMENT FOR PURPOSES OF THE "SAFE HARBOR" PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

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 to be made 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 Part II, Item 7A in our Annual Report on Form 10-K for the year ended December 31, 2001, 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 2001 Annual Report on Form 10-K.

Item 4. Controls and Procedures

Under the supervision and with the participation of our 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 within 90 days of the filing date of this quarterly report pursuant to Rules 13a-15 and 15d-15 under the Securities Exchange Act of 1934 (the "Exchange Act"). Based on that evaluation, our principal executive officer and principal financial officer have concluded that these controls and procedures are effective. There were no significant changes in our internal controls or in other factors that could significantly affect these controls subsequent to the date of their evaluation.

Disclosure controls and procedures 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 and procedures 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.

The principal executive officer and principal financial officer certifications required under Sections 302 and 906 of the Sarbanes-Oxley Act of 2002 have been included herein, or as Exhibits to this Quarterly Report on Form 10-Q, as appropriate.

PART II — OTHER INFORMATION

Item 1. Legal Proceedings.

See Part I, Item 1, Financial Statements, Note 11, which is incorporated herein by reference.

Item 2. Changes in Securities.

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
*99.A	Certification of Chief Executive Officer pursuant to 18 U.S.C. §1350 as adopted pursuant to §906 of the Sarbanes-Oxley Act of 2002.
*99.B	Certification of Chief Financial Officer pursuant to 18 U.S.C. §1350 as adopted pursuant to §906 of the Sarbanes-Oxley Act of 2002.

Undertaking

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

b. Reports on Form 8-K

None.

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 14, 2002

/s/ D. DWIGHT SCOTT

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

Date: November 14, 2002

/s/ JEFFREY I. BEASON

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

CERTIFICATION

I, William A. Wise, certify that:

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

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

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

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

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

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

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

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

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

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

6. The registrant's other certifying officers and I have indicated in this quarterly report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: November 14, 2002

/s/ WILLIAM A. WISE

William A. Wise
Chairman of the Board and
Chief Executive Officer
(Principal Executive Officer)
El Paso CGP Company

CERTIFICATION

I, D. Dwight Scott, certify that:

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

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

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

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

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

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

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

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

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

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

6. The registrant's other certifying officers and I have indicated in this quarterly report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: November 14, 2002

/s/ D. DWIGHT SCOTT

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