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 June 30, 2001

OR

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

For the transition period from to

Commission File Number 1-14365

El Paso Corporation

(Exact Name of Registrant as Specified in its Charter)

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

Registrant's Telephone Number, Including Area Code: **(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 $3.00 per share. Shares outstanding on August 6, 2001: 509,760,907

PART I — FINANCIAL INFORMATION

Item 1. Financial Statements

EL PASO CORPORATION

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

	Quarter Ended June 30,		Six Months Ended June 30,	
	2001	2000	2001	2000
Operating revenues	$13,363	$10,216	$31,117	$19,264
Operating expenses				
Cost of natural gas and other products	11,580	8,663	27,269	16,187
Operation and maintenance	825	574	1,488	1,123
Merger-related costs and asset impairments	601	49	1,762	53
Depreciation, depletion, and amortization	333	304	659	597
Taxes, other than income taxes	100	78	227	154
	13,439	9,668	31,405	18,114
Operating income (loss)	(76)	548	(288)	1,150
Other income				
Earnings from unconsolidated affiliates	100	102	200	170
Other, net	126	34	170	129
	226	136	370	299
Income before interest, income taxes, and other charges	150	684	82	1,449
Interest and debt expense	291	249	586	484
Minority interest	56	49	118	91
Income taxes	(63)	125	(98)	274
	284	423	606	849
Income (loss) before extraordinary items	(134)	261	(524)	600
Extraordinary items, net of income taxes	41	—	31	89
Net income (loss)	$ (93)	$ 261	$ (493)	$ 689
Basic earnings per common share				
Income (loss) before extraordinary items	$ (0.26)	$ 0.53	$ (1.04)	$ 1.22
Extraordinary items, net of income taxes	0.08	—	0.06	0.18
Net income (loss)	$ (0.18)	$ 0.53	$ (0.98)	$ 1.40
Diluted earnings per common share				
Income (loss) before extraordinary items	$ (0.26)	$ 0.52	$ (1.04)	$ 1.19
Extraordinary items, net of income taxes	0.08	—	0.06	0.18
Net income (loss)	$ (0.18)	$ 0.52	$ (0.98)	$ 1.37
Basic average common shares outstanding	505	493	504	492
Diluted average common shares outstanding	505	511	504	508
Dividends declared per common share	$ 0.21	$ 0.21	$ 0.43	$ 0.41

See accompanying notes.

EL PASO CORPORATION

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

	June 30, 2001	December 31, 2000
ASSETS		
Current assets		
Cash and cash equivalents	$ 1,053	$ 741
Accounts and notes receivable, net		
Customer	6,258	6,188
Unconsolidated affiliates	489	304
Other	1,005	896
Inventory	1,009	1,370
Assets from price risk management activities	2,388	4,825
Other	960	832
Total current assets	13,162	15,156
Property, plant, and equipment, at cost		
Pipelines	14,374	14,090
Refining, crude oil, and chemical facilities	2,008	2,606
Power facilities	755	383
Natural gas and oil properties, at full cost	12,376	11,032
Gathering and processing systems	2,825	2,884
Other	936	929
	33,274	31,924
Less accumulated depreciation, depletion, and amortization	15,490	14,924
	17,784	17,000
Additional acquisition cost assigned to utility plant, net	5,193	5,262
Total property, plant, and equipment, net	22,977	22,262
Other assets		
Investments in unconsolidated affiliates	4,517	4,454
Assets from price risk management activities	2,341	1,776
Other	3,212	2,666
	10,070	8,896
Total assets	$46,209	$46,314

See accompanying notes.

EL PASO CORPORATION

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

	June 30, 2001	December 31, 2000
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Accounts and notes payable		
Trade	$ 6,395	$ 5,143
Unconsolidated affiliates	12	14
Other	1,437	1,968
Short-term borrowings (including current maturities of long-term debt)	2,444	3,799
Liabilities from price risk management activities	1,449	3,427
Other	1,833	1,324
Total current liabilities	13,570	15,675
Debt		
Long-term debt, less current maturities	11,839	10,902
Notes payable to unconsolidated affiliates	418	343
	12,257	11,245
Other		
Liabilities from price risk management activities	1,830	1,010
Deferred income taxes	3,732	4,106
Other	3,282	2,452
	8,844	7,568
Commitments and contingencies		
Securities of subsidiaries		
Company-obligated preferred securities of consolidated trusts	925	925
Minority interests	2,793	2,782
	3,718	3,707
Stockholders' equity		
Common stock, par value $3 per share; authorized 750,000,000 shares; issued 517,277,262 shares in 2001 and 513,815,775 shares in 2000	1,552	1,541
Additional paid-in capital	2,245	1,925
Retained earnings	4,534	5,243
Accumulated other comprehensive income	(29)	(65)
Treasury stock (at cost) 7,712,051 shares in 2001 and 13,943,779 shares in 2000	(260)	(400)
Unamortized compensation	(222)	(125)
Total stockholders' equity	7,820	8,119
Total liabilities and stockholders' equity	$46,209	$46,314

See accompanying notes.

EL PASO CORPORATION

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

	Six Months Ended June 30, 2001	Six Months Ended June 30, 2000
Cash flows from operating activities		
Net income (loss)	$ (493)	$ 689
Adjustments to reconcile net income (loss) to net cash from operating activities		
Depreciation, depletion, and amortization	659	597
Deferred income tax expense (benefit)	(73)	140
Net gain on the sale of assets	(12)	(24)
Extraordinary items	(53)	(149)
Undistributed earnings of unconsolidated affiliates	(93)	(62)
Non-cash portion of merger-related costs and asset impairments	1,258	—
Other	245	(13)
Working capital changes, net of non-cash transactions	1,403	(1,209)
Other	(287)	(46)
Net cash provided by (used in) operating activities	2,554	(77)
Cash flows from investing activities		
Purchases of property, plant, and equipment	(1,740)	(1,696)
Additions to investments	(571)	(1,063)
Cash paid for acquisitions, net of cash received	—	(163)
Net proceeds from the sale of assets	332	510
Proceeds from the sale of investments	151	364
Repayment of notes receivable from unconsolidated affiliates	172	647
Other	2	25
Net cash used in investing activities	(1,654)	(1,376)
Cash flows from financing activities		
Net repayments of commercial paper and short-term notes	(1,232)	(491)
Revolving credit borrowings	595	425
Revolving credit repayments	(810)	(460)
Payments to retire long-term debt	(830)	(314)
Net proceeds from the issuance of long-term debt	2,140	969
Net proceeds from the issuance of preferred securities	—	293
Issuances of common stock	37	50
Dividends paid	(167)	(120)
Net proceeds from the issuance of minority interests in subsidiaries	—	245
Increase in notes payable to unconsolidated affiliates	375	544
Decrease in notes payable to unconsolidated affiliates	(743)	(82)
Net proceeds from the issuance of notes payable	47	—
Net cash provided by (used in) financing activities	(588)	1,059
Increase (decrease) in cash and cash equivalents	312	(394)
Cash and cash equivalents		
Beginning of period	741	589
End of period	$1,053	$ 195

See accompanying notes.

EL PASO CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME AND CHANGES IN ACCUMULATED OTHER COMPREHENSIVE INCOME

(In millions)
(Unaudited)

Comprehensive Income (Loss)	Quarter Ended June 30, 2001	Quarter Ended June 30, 2000	Six Months Ended June 30, 2001	Six Months Ended June 30, 2000
Net income (loss)	$ (93)	$261	$ (493)	$689
Unrealized net gains (losses) from cash flow hedging activity				
Cumulative-effect transition adjustment (net of tax of $673)	—	—	(1,280)	—
Reclassification of initial cumulative-effect transition adjustment at original value (net of tax of $97 and $419)	181	—	782	—
Additional reclassification adjustments for changes in initial value to settlement date (net of tax of $38 and $35)	38	—	(100)	—
Unrealized mark-to-market gains arising during period (net of tax of $450 and $327)	891	—	652	—
Other	(4)	(4)	(18)	(9)
Comprehensive income (loss)	$1,013	$257	$ (457)	$680

Accumulated Other Comprehensive Income	2001	2000
Beginning balances as of December 31, 2000 and 1999	$ (65)	$(29)
Unrealized net gains (losses) from cash flow hedging activity		
Cumulative-effect transition adjustment, net of taxes	(1,280)	—
Reclassification of initial cumulative-effect transition adjustment at original value, net of taxes	782	—
Additional reclassification adjustments for changes in initial value to settlement date, net of taxes	(100)	—
Unrealized mark-to-market gains arising during period, net of taxes	652	—
Other	(18)	(9)
Balance as of June 30,	$ (29)	$(38)

See accompanying notes.

EL PASO CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

1. Basis of Presentation

In January 2001, we completed our merger with The Coastal Corporation. The transaction was accounted for as a pooling of interests. Therefore, the financial information in this Quarterly Report on Form 10-Q reflects our operations as though our companies had been combined since the earliest period presented. On May 17, 2001, we filed a Current Report on Form 8-K/A that included combined audited financial statements for the same periods as required in our 2000 Annual Report on Form 10-K. You should read that Form 8-K/A in conjunction with this Quarterly Report on Form 10-Q. The financial statements as of June 30, 2001, and for the quarters and six months ended June 30, 2001 and 2000, are unaudited. The balance sheet as of December 31, 2000, is derived from the audited balance sheet filed in the Form 8-K/A. These financial statements have been prepared pursuant to the rules and regulations of the U.S. Securities and Exchange Commission and do not include all disclosures required by accounting principles generally accepted in the United States. In our opinion, we have made all adjustments, all of which are of a normal, recurring nature (except for merger-related costs and asset impairments discussed in Note 3 and changes in accounting estimates discussed in Note 4), to fairly present our interim period results. Information for interim periods may not necessarily indicate the results of operations for the entire year due to the seasonal nature of our businesses. The prior period information also includes reclassifications which were made to conform to the current period presentation. These reclassifications have no effect on our reported net income or stockholders' equity.

Our accounting policies are consistent with those discussed in our Form 8-K/A, except as discussed below. You should refer to the Form 8-K/A for a further discussion of those policies.

Accounting for Price Risk Management Activities

Our business activities expose us to a variety of risks, including commodity price risk, interest rate risk, and foreign currency risk. Our corporate risk management group identifies risks associated with our businesses and determines which risks we want to manage and which types of instruments we should use to manage those risks.

With the adoption of Statement of Financial Accounting Standards (SFAS) No. 133, *Accounting for Derivatives and Hedging Activities,* we now record all derivative instruments on the balance sheet at their fair value. These instruments consist of two types, those derivatives entered into and held to mitigate, or hedge a particular risk, and those that are entered into and held for purposes other than risk mitigation, such as those in our trading activities. Those instruments that do not qualify as hedges are recorded at their fair value with changes in fair value reported in current period earnings. For those instruments entered into to hedge risk, and which qualify as hedges under SFAS No. 133, the appropriate accounting treatment depends on each instrument's intended use and how it is designated. Derivative instruments that qualify as hedges may be designated as:

- hedges of the fair value of a recognized asset or liability or of an unrecognized firm commitment (fair value hedges);
- hedges of a forecasted transaction or of the variability of cash flows to be received or paid related to a recognized asset or liability (cash flow hedges);
- foreign currency fair value or cash flow hedges (foreign currency hedges); or
- hedges of a net investment in a foreign operation (net investment hedges).

In addition to its designation, a hedge must be effective. To be effective, the value of the derivative or its resulting cash flows must substantially offset changes in the value or cash flows of the item being hedged. If it is determined that the hedge is no longer effective, hedge accounting is discontinued prospectively. Hedge accounting is also discontinued when:

- the derivative instrument expires or is sold, terminated, or exercised;
- it is no longer probable that the forecasted transaction will occur;
- the hedged firm commitment no longer meets the definition of a firm commitment; or
- management determines that the designation of the derivative instrument as a hedge is no longer appropriate.

At the time we enter into a hedge, we formally document relationships between the hedging instrument and the hedged item. This documentation includes:

- the nature of the risk being hedged;
- our risk management objectives and strategies for undertaking the hedging activity;
- a description of the hedged item and the derivative instrument used to hedge the item;
- a description of how effectiveness is tested at the inception of the hedge; and
- how effectiveness will be tested on an ongoing basis.

When hedge accounting is discontinued, the derivative instrument continues to be carried on the balance sheet at its fair value. However, any further changes in its fair value are recognized in current period earnings. Accounting for the item that was being hedged differs depending on how the hedge was originally designated. Our accounting policies for derivative instruments used in our business that qualify as hedges are discussed below:

Type of Hedge	Accounting Treatment	Impact of the Discontinuation of Hedge Accounting on Item Being Hedged
Fair value	Changes in the fair value of the derivative and changes in the fair value of the related asset or liability attributable to the hedged risk are recorded in current period earnings, generally as a component of revenue in the case of a sale or as a component of the cost of products in the case of a purchase.	When hedge accounting is discontinued, the hedged asset or liability is no longer adjusted for changes in fair value. When hedge accounting is discontinued because the hedged item no longer meets the definition of a firm commitment, any asset or liability that was recorded related to the firm commitment is removed from the balance sheet and recognized in current period earnings.
Cash flow	Changes in the fair value of the derivative are recorded in other comprehensive income for the portion of the change in value of the derivative that is effective. The ineffective portion of the derivative is recorded in earnings in the current period. Classification in the income statement of the ineffective portion is based on the income classification of the item being hedged.	When hedge accounting is discontinued because it is unlikely that the forecasted transaction will occur, gains or losses that were accumulated in other comprehensive income related to the forecasted transaction will be recognized immediately in earnings. When a cash flow hedge is de-designated, but the forecasted transaction is still probable, the accumulated amounts remain in other comprehensive income until the forecasted transaction occurs. At that time, the accumulated amounts are recognized in earnings.

Type of Hedge	Accounting Treatment	Impact of the Discontinuation of Hedge Accounting on Item Being Hedged
Foreign currency	Changes in the fair value of the derivative are recorded in current period earnings if it qualifies as a fair value hedge, or in other comprehensive income if it qualifies as a cash flow hedge.	If hedge accounting is discontinued, accounting for the hedged item depends on whether the hedge is a fair value hedge or a cash flow hedge, and follows the accounting discussed above.

Because our business activities encompass all aspects of the wholesale energy marketplace, including the production, gathering, processing, treating, transmission, refining, and the purchase and sale of highly liquid energy commodities, our normal business contracts may qualify as derivative instruments under the provisions of SFAS No. 133. As a result, we evaluate each of our commercial contracts to see if derivative accounting is appropriate. Contracts that meet the criteria of a derivative are then evaluated to determine whether they qualify as a "normal purchase" or a "normal sale" as those terms are defined in SFAS No. 133. If they qualify as normal purchases and normal sales, we may exclude them from SFAS No. 133 treatment. We also evaluate our contracts for "embedded" derivatives. Embedded derivatives have terms that are not clearly and closely related to the terms of the contract in which they are included. If embedded derivatives exist, they are accounted for separately from the host contract as derivatives, with changes in their fair value recorded in current period earnings.

2. Merger with Coastal

In January 2001, we merged with Coastal. We accounted for the transaction as a pooling of interests and converted each share of Coastal's common stock and Class A common stock on a tax-free basis into 1.23 shares of our common stock. We exchanged Coastal's outstanding convertible preferred stock for our common stock on the same basis as if the preferred stock had been converted into Coastal common stock immediately prior to the merger. The total value of the transaction was approximately $24 billion, including $7 billion of assumed debt and preferred equity. In the merger, we issued approximately 271 million shares of our common stock, including 4 million shares issued in exchange for Coastal stock options.

The following table presents the revenues and net income for the previously separate companies and the combined amounts presented in these financial statements for the periods ended June 30:

	Quarter Ended June 30, 2000	Six Months Ended June 30, 2000
	(In millions)	
Revenues		
El Paso	$ 4,250	$ 7,382
Coastal	3,992	7,589
Conforming reclassifications[1]	1,974	4,293
Combined	$10,216	$19,264
Extraordinary items, net of income taxes		
El Paso	$ —	$ 89
Coastal	—	—
Combined	$ —	$ 89
Net income		
El Paso	$ 134	$ 388
Coastal	127	301
Combined	$ 261	$ 689

[1] Conforming reclassifications include a gross-up of revenues associated with Coastal's physical petroleum marketing and trading activities to be consistent with our method of reporting these revenues.

Under a Federal Trade Commission (FTC) order, as a result of our merger with Coastal, we sold our Midwestern Gas Transmission system, 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 quarter and six months ended June 30, 2001, net proceeds from these sales were approximately $135 million and $279 million, and we recognized extraordinary net gains of approximately $41 million and $31 million, net of income taxes of approximately $23 million and $22 million.

Additionally, El Paso Energy Partners, L.P. sold its interests in several offshore assets. These sales consisted of interests in eight natural gas pipeline systems, a dehydration facility, and two offshore platforms. Proceeds from the sales of these assets were approximately $135 million and resulted in a loss to the partnership of approximately $25 million. As consideration for these sales, we committed to pay Energy Partners a series of payments totaling $29 million. We were also required to contribute $40 million to a trust related to one of the assets sold by Energy Partners. These payments have been recorded as merger-related costs.

We do not anticipate the impact from these sales to be material to our ongoing financial position, operating results, or cash flows.

During the six months ended June 30, 2000, we sold East Tennessee Natural Gas Company, Sea Robin Pipeline Company, and our one-third interest in Destin Pipeline Company to comply with an FTC order related to our merger with Sonat Inc. Net proceeds from these sales were approximately $616 million, and we recognized an extraordinary gain of $89 million, net of income taxes of $60 million.

3. Merger-Related Costs and Asset Impairments

During the quarter and six months ended June 30, we incurred merger-related costs associated with our merger with Coastal and asset impairments as follows:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2001	2000	2001	2000
	(In millions)			
Merger-related costs	$494	$49	$1,655	$53
Asset impairments	107	—	107	—
	$601	$49	$1,762	$53

Merger-Related Costs

Our merger-related costs consisted of the following:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2001	2000	2001	2000
	(In millions)			
Employee severance, retention, and transition costs	$ 19	$—	$ 821	$—
Transaction costs	19	49	67	53
Business and operational integration costs	395	—	416	—
Merger-related asset impairments	19	—	152	—
Other	42	—	199	—
	$494	$49	$1,655	$53

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 the Coastal merger, we completed an employee restructuring across all of our operating segments, resulting in the reduction of 3,285 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 this restructuring. Retention charges include payments to employees who were retained following the merger 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. Substantially all of the costs accrued in connection with these activities had been paid as of June 30, 2001.

Also included in employee severance, retention, and transition costs for the six months ended June 30, 2001, was a charge of $278 million resulting from the issuance of approximately 4 million shares of common stock in exchange for the fair value of Coastal employees' stock options.

Transaction costs include investment banking, legal, accounting, consulting, and other advisory fees incurred to obtain federal and state regulatory approvals and take other actions necessary to complete our merger.

Business and operational integration costs include charges to consolidate facilities and operations of our business segments, such as lease termination and abandonment charges, recognition of the mark-to-market value of energy trading contracts resulting from changes in how these contracts are managed under our combined operating strategy, and incremental fees under software and seismic license agreements.

Merger-related asset impairments 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. These charges occurred in our Merchant Energy and Pipelines segments, and all of these assets continue to be held for use.

Other costs include payments made in satisfaction of obligations arising from the FTC approval of the merger and other miscellaneous charges.

Asset Impairments

During the quarter ended June 30, 2001, we incurred other asset impairment charges of $107 million. These charges consisted of a $60 million write-down of corporate-owned private equity investments, primarily a non-strategic communications company in Brazil, and charges of $47 million primarily related to Merchant Energy's impairment of its East Asia Power investment in the Philippines. These write-downs were a result of weak economic conditions causing a permanent decline in the value of these investments. We continue to hold all of these investments.

4. Changes in Accounting Estimates

Included in our operation and maintenance costs for the quarter and six months ended June 30, 2001, are approximately $204 million in costs related to changes in our estimates of environmental remediation liabilities and the usability of spare parts inventory in our worldwide operations. Both charges arose as a result of an ongoing evaluation of our operating standards and plans following our merger with Coastal and our combined operating strategy. These changes in estimates reduced net income before extraordinary items and net income by approximately $139 million.

5. Earnings Per Share

Our computation of basic and diluted earnings per common share for the periods ended June 30 is presented below:

	Quarter Ended June 30,		
	2001	2000	
	Basic[(1)]	Basic	Diluted
	(In millions, except per common share amounts)		
Income (loss) before extraordinary items	$ (134)	$ 261	$ 261
Interest on trust preferred securities and preferred stock dividends, net of income taxes	—	—	3
Adjusted income (loss) before extraordinary items	(134)	261	264
Extraordinary items, net of income taxes	41	—	—
Adjusted net income (loss)	$ (93)	$ 261	$ 264
Average common shares outstanding	505	493	493
Effect of dilutive securities			
Stock options	—	—	7
Preferred stock	—	—	1
FELINE PRIDES^{SM}	—	—	2
Trust preferred securities	—	—	8
Average common shares outstanding	505	493	511
Earnings (loss) per common share			
Adjusted income (loss) before extraordinary items	$(0.26)	$0.53	$0.52
Extraordinary items, net of income taxes	0.08	—	—
Adjusted net income (loss)	$(0.18)	$0.53	$0.52

	Six Months Ended June 30,		
	2001	2000	
	Basic[(1)]	Basic	Diluted
	(In millions, except per common share amounts)		
Income (loss) before extraordinary items	$ (524)	$ 600	$ 600
Interest on trust preferred securities and preferred stock dividends, net of income taxes	—	—	5
Adjusted income (loss) before extraordinary items	(524)	600	605
Extraordinary items, net of income taxes	31	89	89
Adjusted net income (loss)	$ (493)	$ 689	$ 694
Average common shares outstanding	504	492	492
Effect of dilutive securities			
Stock options	—	—	6
Preferred stock	—	—	1
FELINE PRIDES^{SM}	—	—	1
Trust preferred securities	—	—	8
Average common shares outstanding	504	492	508
Earnings (loss) per common share			
Adjusted income (loss) before extraordinary items	$(1.04)	$1.22	$1.19
Extraordinary items, net of income taxes	0.06	0.18	0.18
Adjusted net income (loss)	$(0.98)	$1.40	$1.37

(1) Due to the loss from continuing operations, adding potentially dilutive securities would have an antidilutive effect to earnings per share resulting in a lower loss per share.

6. Accounting for Hedging Activities

On January 1, 2001, we adopted the provisions of SFAS No. 133, and recorded a cumulative-effect adjustment of $1,280 million, net of income taxes, in accumulated other comprehensive income to recognize the fair value of all derivatives designated as cash flow hedging instruments. The majority of the initial charge related to hedging forecasted sales of natural gas for 2001 and 2002. During the quarter and six months ended June 30, 2001, $181 million and $782 million, net of income taxes, of this initial transition adjustment was reclassified to earnings as a result of hedged sales and purchases during the periods, and an additional $279 million of this adjustment will be reclassified by the end of 2001. A discussion of our hedging activities is as follows:

Fair Value Hedges. We have crude oil and refined products inventories that change in value daily due to changes in the commodity markets. We use futures and swaps to protect the value of these inventories. For the quarter and six months ended June 30, 2001, the financial statement impact of our hedges of the fair value of these inventories was immaterial.

Cash Flow Hedges. A majority of our commodity sales and purchases are at spot market or forward market prices. We use futures, forward contracts, and swaps to limit our exposure to fluctuations in the commodity markets and allow for a fixed cash flow stream from these activities. As of June 30, 2001, the value of cash flow hedges included in accumulated other comprehensive income was an unrealized gain of $54 million, net of income taxes. Of this amount, we estimate that $31 million will be reclassified from accumulated other comprehensive income over the next 12 months. Reclassifications occur upon physical delivery of the hedged commodity and the corresponding expiration of the hedge. The maximum term of our cash flow hedges is 12 years; however, most of our cash flow hedges expire within the next 24 months.

Our other comprehensive income also includes our proportionate share of amounts recorded in other comprehensive income by our unconsolidated affiliates who use derivatives as cash flow hedges.

Foreign Currency Hedges. In our international activities, we have fixed rate foreign currency denominated debt that exposes us to changes in exchange rates between the foreign currency and U.S. dollar. During the quarter ended June 30, 2001, we used a currency swap to effectively convert the fixed amounts of foreign currency due under foreign currency denominated debt to fixed U.S. dollar amounts. See Note 9 for further information.

For the quarter and six months ended June 30, 2001, we recognized net gains of $12 million and $13 million, net of income taxes, related to the ineffective portion of all cash flow hedges.

7. Property, Plant, and Equipment

In June 2001, we entered into a 20-year agreement related to our Corpus Christi refinery with Valero Energy Corporation that qualified as a sales-type capital lease. The net investment of the lease at June 30, 2001, discounted using a rate of 7.5%, consisted of the following:

	June 30, 2001
	(In millions)
Minimum lease payments	$288
Estimated residual value	91
Net investment	$379

At June 30, 2001, the undiscounted minimum lease payments are as follows: $14 million in 2001; $19 million in 2002; $37 million in 2003; and $43 million per year thereafter.

8. Inventory

Our inventory consisted of the following:

	June 30, 2001	December 31, 2000
	(In millions)	
Refined products, crude oil, and chemicals	$ 737	$1,011
Coal, materials and supplies, and other	248	266
Natural gas in storage	24	93
Total	$1,009	$1,370

9. Debt and Other Credit Facilities

At June 30, 2001, our weighted average interest rate on short-term borrowings was 4.4%, and at December 31, 2000, it was 7.4%. We had the following short-term borrowings, including current maturities of long-term debt:

	June 30, 2001	December 31, 2000
	(In millions)	
Short-term credit facility	$ —	$ 455
Notes payable	—	343
Notes payable to unconsolidated affiliates	95	396
Commercial paper	524	1,416
Other credit facilities	250	10
Current maturities of long-term debt	1,575	1,179
	$2,444	$3,799

Acquisition of PG&E's Texas Midstream Operations

In connection with our acquisition of PG&E's Texas Midstream operations in December 2000, we assumed $527 million in debt. We also established a $700 million short-term credit facility for use in connection with this acquisition and borrowed $455 million under this facility in December 2000. In February 2001, we borrowed the balance of this facility and redeemed $293 million of debt assumed from PG&E. In two payments occurring in March and June 2001, we repaid the outstanding balance of the credit facility, and the facility was terminated.

Revolving Credit Facilities

In January 2001, Coastal terminated approximately $1.5 billion in revolving credit facilities and became a designated borrower under our 364-day and our 3-year revolving credit and competitive advance facilities. In June 2001, we replaced our 364-day revolving credit facility with a renewable $3 billion, 364-day revolving credit and competitive advance facility. El Paso Natural Gas Company (EPNG) and Tennessee Gas Pipeline Company (TGP) are designated borrowers under the new facility. Coastal, EPNG, and TGP remain designated borrowers under our 3-year facility. The interest rate on these facilities varies and was LIBOR plus 50 basis points at June 30, 2001. No amounts were outstanding under these facilities at June 30, 2001.

Other

In February 2001, Southern Natural Gas (SNG) issued $300 million aggregate principal amount 7.35% notes due 2031. Proceeds of approximately $297 million, net of issuance costs, were used to pay off $100 million of SNG's 8.875% notes due 2001 and for general corporate purposes.

Also in February 2001, we issued approximately $1.8 billion zero coupon convertible debentures due 2021, with a yield to maturity of 4%. Proceeds of approximately $784 million, net of issuance costs, were used to repay short-term borrowings and for general corporate purposes. These debentures are convertible into 8,456,589 shares of our common stock which is based on a conversion rate of 4.7872 shares per $1,000 principal amount at maturity. This rate was equivalent to an initial conversion price of $94.604 per share of our common stock.

In March 2001, we issued €550 million (approximately $510 million) of euro notes at 5.75% due 2006. Proceeds of approximately $505 million, net of issuance costs, were used to repay short-term debt and for general corporate purposes. To reduce our exposure to foreign currency risk, we entered into a swap transaction exchanging the euro note for a $510 million U.S. dollar denominated obligation with a fixed interest rate of 6.61% for the five-year term of the note.

In April 2001, we filed a shelf registration with the Securities and Exchange Commission to sell, from time to time, up to a total of $3 billion in debt securities, preferred and common stock, medium term notes, or trust securities.

In May 2001, we issued $500 million aggregate principal amount 7.00% notes due 2011. Proceeds of approximately $496 million, net of issuance costs, were used to repay short-term indebtedness and for general corporate purposes.

In addition to the items discussed above, during the six months ended June 30, 2001, we issued $45 million of long-term debt and retired long-term debt with the aggregate principal amount of approximately $256 million.

In July 2001, we issued $700 million aggregate principal amount 7.80% medium term notes due 2031. Net proceeds of approximately $689 million, net of issuance costs, were used to repay our short-term borrowings and for general corporate purposes.

10. Commitments and Contingencies

Legal Proceedings

We and several of our subsidiaries were named defendants in eight purported class action or citizen lawsuits and one individual lawsuit filed in 2000 and 2001 in California state courts (a list of the *California* cases is included in Part II, Item 1, Legal Proceedings). These cases contend generally that our entities acted alone or in combination with other unrelated companies to create artificially high prices for natural gas in California, and that EPME's acquisition of capacity on the EPNG pipeline system was utilized to manipulate the market for natural gas in California. We removed each of these cases to federal court and have requested that they be consolidated for all pretrial activities. In June 2001, the Federal Judicial Panel on Multi-District Litigation granted our consolidation motion relating to four of the lawsuits, sending them to the U.S. District Court in Nevada. In July 2001, the remaining five cases were conditionally consolidated to the Nevada District Court. The Nevada court has scheduled oral arguments in September 2001 on the issue of whether some or all of these cases should be remanded to the California state court system for all further proceedings.

On August 19, 2000, a main transmission line owned and operated by EPNG ruptured at the crossing of the Pecos River near Carlsbad, New Mexico. Twelve individuals at the site were fatally injured. Eleven lawsuits brought on behalf of the 12 deceased persons have been filed against us for damages for personal injuries and wrongful death (a list of the *Carlsbad* cases is included in Part II, Item 1, Legal Proceedings). In March 2001, we settled all claims in the *Heady* cases, and in June 2001, we settled the claims in the *Jennifer Smith* case. Payments for the claimants in the settled cases will be fully covered by insurance. We are cooperating with the National Transportation Safety Board in an investigation into the facts and circumstances concerning the possible causes of the rupture. In addition, on June 20, 2001, the U.S. Department of Transportation's Office of Pipeline Safety issued a Notice of Proposed Violation to EPNG. The Notice alleged five probable violations of its regulations (a list of the alleged five probable violations is included in Part II, Item 1, Legal Proceedings), proposed fines totaling $2.5 million, and proposed corrective actions. On July 20, 2001, EPNG contested the proposed violations in its response to the Office of Pipeline Safety.

In August 2000, the Liquidating Trustee in the bankruptcy of Power Corporation of America (PCA) sued El Paso Merchant Energy (EPME), and several other power traders, in the U.S. Bankruptcy Court in Connecticut claiming EPME improperly cancelled its contracts with PCA during the summer of 1998. The trustee alleged we breached contracts damaging PCA in the amount of $120 million. In May 2001, we agreed to settle this matter for a cash payment of $3 million. In a related matter, PCA appealed the Federal Energy Regulatory Commission's (FERC) ruling that power marketers such as EPME did not have to give 60 days notice to cancel its power contracts under the Federal Power Act. PCA has appealed this decision to the United States Court of Appeals, which ruled in FERC's favor.

In February 1998, the United States and the state of Texas filed in a U.S. District Court a Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) cost recovery action against 14 companies, including some of our current and former affiliates, related to the Sikes Disposal Pits Superfund Site located in Harris County, Texas. The suit claims that the United States and the state of Texas have spent over $125 million in remediating Sikes and seeks to recover that amount plus interest from the defendants to the suit. The Environmental Protection Agency (EPA) has recently indicated that it may seek an additional amount up to $30 million, plus interest, in indirect costs from the defendants under a new cost allocation methodology. Defendants are challenging this allocation policy. Although an investigation relating to Sikes is ongoing, we believe that the amount of material, if any, disposed at Sikes by our former affiliates was small, possibly *de minimis*. However, the plaintiffs have alleged that the defendants are each jointly and severally liable for the entire remediation costs and have also sought a declaration of liability for future response costs such as groundwater monitoring. Settlement discussions are ongoing.

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 under report 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. 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). In May 2001, the court denied the defendants' motions to dismiss.

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. 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 Quinque complaint was transferred to the same court handling the Grynberg complaint and has now been sent back to Kansas State Court for further proceedings.

In October 1992, several property owners in McAllen, Texas, filed suit in the 93rd Judicial District Court, Hidalgo County, Texas, against, among others, one of our subsidiaries (*Timely Adventures, Inc. et al,* v. *Phillips Properties, Inc., et al* and *Garza* v. *Coastal Mart, Inc.*). The suit sought damages for the alleged diminution of property value and damages related to the exposure to hazardous chemicals arising from the operation of service stations and storage facilities. In July 2000, the trial court entered a judgment for approximately $1.2 million in actual damages for property diminution and approximately $100 million in punitive damages. The judgment is being appealed.

In November 1988, the Kentucky environmental agency filed a complaint in a Kentucky state court alleging that TGP discharged pollutants into the waters of the state and disposed of polychlorinated biphenyls (PCBs) without a permit. The agency sought an injunction against future discharges, an order to remediate or remove PCBs, and a civil penalty. TGP entered into agreed orders with the agency to resolve many of the issues raised in the original allegations and received water discharge permits from the agency for its Kentucky compressor stations. The relevant Kentucky compressor stations are being characterized and remediated under a 1994 consent order with the EPA.

We are also a named defendant in numerous lawsuits and a named party in numerous governmental proceedings arising in the ordinary course of our business.

While the outcome of the matters discussed above cannot be predicted with certainty, we do not expect the ultimate resolution of these matters will have a material adverse effect on our financial position, operating results, or cash flows.

Environmental

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 June 30, 2001, we had a reserve of approximately $463 million for expected remediation costs. In addition, we expect to make capital expenditures for environmental matters of approximately $300 million in the aggregate for the years 2001 through 2006. These expenditures primarily relate to compliance with clean air regulations.

From March to October 2000, our Eagle Point Oil Company received several Administrative Order Notices of Civil Administrative Penalty Assessment from the New Jersey Department of Environmental Protection. All of the assessments are related to similar alleged noncompliances with the New Jersey Air Pollution Control Act pertaining to occurrences of air pollution from the second quarter 1998 through the third quarter 2000 by Eagle Point's refinery in Westville, New Jersey. The New Jersey Department of Environmental Protection has assessed penalties totaling approximately $1 million for these alleged violations. Eagle Point has requested an administrative hearing on all issues raised by the assessments and, concurrently, is in negotiations to settle these assessments.

Since 1988, TGP has been engaged in an internal project to identify and deal with the presence of PCBs and other substances, including those on the EPA List of Hazardous Substances, at compressor stations and other facilities it operates. While conducting this project, TGP has been in frequent contact with federal and state regulatory agencies, both through informal negotiation and formal entry of consent orders, to ensure that its efforts meet regulatory requirements.

In May 1995, following negotiations with its customers, TGP filed a Stipulation and Agreement (the Environmental Stipulation) with FERC that established a mechanism for recovering a substantial portion of the environmental costs identified in its internal project. The Environmental Stipulation was effective July 1, 1995, and all amounts have been collected from customers. Refunds may be required to the extent actual eligible expenditures are less than amounts collected.

TGP is a party in proceedings involving federal and state authorities regarding the past use of a lubricant containing PCBs in its starting air systems. TGP executed a consent order in 1994 with the EPA governing the remediation of the relevant compressor stations and is working with the EPA and the relevant states regarding those remediation activities. TGP is also working with the Pennsylvania and New York environmental agencies regarding remediation and post-remediation activities at the Pennsylvania and New York stations.

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 53 active sites under CERCLA or state equivalents. We have sought to resolve our liability as a PRP at these CERCLA sites, as appropriate, through indemnification by third parties and/or settlements which provide for payment of our allocable share of remediation costs. As of June 30, 2001, we have estimated our share of the remediation costs at these sites to be between approximately $72 million and $208 million and have provided reserves that we believe are adequate for such costs. Since the cleanup 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 the determination of our estimated liabilities. We presently believe that the costs associated with these CERCLA sites will not 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 environmental matters. We may incur significant costs and liabilities in order to comply with existing environmental laws and regulations. It is also possible that other developments, such as increasingly strict environmental laws and regulations and claims for damages to property, employees, other persons and the environment resulting from our current or past operations, could result in substantial costs and liabilities in the future. As this information becomes available, or other relevant developments occur, we will adjust our accrual amounts accordingly. While there are still uncertainties relating to the ultimate costs we may incur, based upon our evaluation and experience to date, we believe the recorded reserves are adequate. For a further discussion of specific environmental matters, see Legal Proceedings above.

Rates and Regulatory Matters

In April 2000, the California Public Utilities Commission (CPUC) filed a complaint with FERC alleging that EPNG's sale of approximately 1.2 billion cubic feet per day of California capacity to EPME was anticompetitive and an abuse of the affiliate relationship under FERC's policies. In August 2000, the CPUC filed a motion requesting that the contract between EPNG and EPME be terminated. Other parties in the proceedings have requested that the original complaint be set for hearing and that EPME pay back any profits it has earned under the contract. In March 2001, FERC established a hearing, before an administrative law judge, to address the issue of whether EPNG and/or EPME had market power and, if so, had exercised it. The hearing on the anticompetitive issue concluded in May 2001. In June 2001, FERC issued an order granting the request of the CPUC and others to allow the administrative law judge to take evidence on the affiliate abuse issue. The hearing for the purpose of taking evidence on this issue concluded on August 6, 2001, with final briefs due by September 9, 2001. We expect the administrative law judge to issue a decision in the fourth quarter 2001.

Two groups of EPNG's customers, those within California and those east of California, have recently filed complaints with FERC. The filings involve a dispute over the allocation of pipeline capacity. In July 2001, twelve parties composed of California customers, natural gas producers, and natural gas marketers, filed a complaint against EPNG with FERC. The complaint alleges that EPNG's full requirements contracts with its east of California customers should be converted to contracts with specific volumetric entitlements, that EPNG should be required to expand its interstate pipeline system, and that firm shippers who experience reductions in their nominated gas volumes should be awarded demand charge credits. EPNG filed its response to this complaint on August 2, 2001. In July 2001, ten parties, most of which are east of California full-requirement contract customers, filed a complaint against EPNG with FERC, alleging that EPNG violated the Natural Gas Act of 1938 and breached its contractual obligations by failing to expand its system in order to serve the needs of the full-requirement contract shippers. The complainants have requested that FERC require EPNG to show cause why it should not be required to augment its system capacity. EPNG filed its response to this complaint on August 6, 2001, and requested that both groups' complaints be consolidated for future proceedings.

In June 2001, the Western Australia regulators issued a draft rate decision at lower than expected levels for the Dampier-to-Bunbury pipeline owned by EPIC Energy Australia Trust (EPIC), in which we have a 33 percent ownership interest. EPIC's management is currently analyzing the impact of the draft rate decision on its current and anticipated future operating results, the results of which could impact our investment.

While we cannot predict with certainty the final outcome or the timing of the resolution of all of our rates and regulatory matters, we believe the ultimate resolution of these issues will not have a material adverse effect on our financial position, results of operations, or cash flows.

Other

In May 2001, we entered into an operating lease for the Lakeside Technology Center, a telecommunications carrier hotel located in Chicago, Illinois. The lease term expires in 2006, at which time we have an option to buy the facility for approximately $275 million. If we do not purchase the facility at the end of the lease term, we have an obligation to pay a residual guaranty amount equal to approximately 86 percent of the purchase option price. Payments under the lease are indexed to the lessor's financing costs and are subject to change as a result of changes in LIBOR. Based on LIBOR at June 30, 2001, aggregate minimum lease payments totaled $69 million; $8 million in 2001; $14 million in 2002 through 2005; and $5 million thereafter. For the quarter and six months ended June 30, 2001, we recorded rental expense of $2 million for this lease.

In April 2001, we entered into agreements to charter two separate ships to secure transportation for our developing liquefied natural gas business. The agreements commence in 2003 and 2004, and each agreement has a 20-year term with the possibility of two 5-year extensions. In June 2001, we exercised options to charter 2 additional ships.

11. Segment Information

We segregate our business activities into four distinct operating segments: Pipelines, Merchant Energy, Production, 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. We measure segment performance using earnings before interest expense and income taxes (EBIT). The following are our results as of and for the periods ended June 30:

	Quarter Ended June 30, 2001					
	Pipelines	Merchant Energy	Production	Field Services	Other[(1)]	Total
			(In millions)			
Revenues from external customers	$ 568	$12,390	$ —	$ 289	$ 116	$13,363
Intersegment revenues	84	206	570	115	(975)	—
Merger-related costs and asset impairments	226	58	—	9	308	601
Operating income (loss)	31	(16)	286	40	(417)	(76)
EBIT	69	134	289	55	(397)	150
Segment assets	14,101	16,389	7,736	4,137	3,846	46,209

	Quarter Ended June 30, 2000					
	Pipelines	Merchant Energy	Production	Field Services	Other[(1)]	Total
			(In millions)			
Revenues from external customers	$ 563	$ 8,739	$ 330	$ 277	$ 307	$10,216
Intersegment revenues	46	(16)	79	28	(137)	—
Merger-related costs and asset impairments	—	—	—	—	49	49
Operating income (loss)	255	149	173	40	(69)	548
EBIT	295	245	169	52	(77)	684
Segment assets	13,950	12,565	5,233	1,950	2,100	35,798

	Six Months Ended June 30, 2001					
	Pipelines	Merchant Energy	Production	Field Services	Other[(1)]	Total
			(In millions)			
Revenues from external customers	$ 1,283	$28,374	$ 220	$ 936	$ 304	$31,117
Intersegment revenues	161	631	906	225	(1,923)	—
Merger-related costs and asset impairments	315	194	63	38	1,152	1,762
Operating income (loss)	325	153	474	60	(1,300)	(288)
EBIT	402	392	474	91	(1,277)	82
Segment assets	14,101	16,389	7,736	4,137	3,846	46,209

	Six Months Ended June 30, 2000					
	Pipelines	Merchant Energy	Production	Field Services	Other[(1)]	Total
			(In millions)			
Revenues from external customers	$ 1,254	$16,335	$ 597	$ 498	$ 580	$19,264
Intersegment revenues	94	156	190	51	(491)	—
Merger-related costs and asset impairments	—	—	—	—	53	53
Operating income (loss)	609	216	331	82	(88)	1,150
EBIT	685	397	323	108	(64)	1,449
Segment assets	13,950	12,565	5,233	1,950	2,100	35,798

(1) Includes Corporate and eliminations as well as our telecommunication and retail operations.

12. Investments in Unconsolidated Affiliates

We hold investments in various affiliates which we account for using the equity method of accounting. Summarized financial information for our proportionate share of these investments is as follows:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2001	2000	2001	2000
	(In millions)			
Operating results data				
Revenues and other income	$918	$2,606	$1,444	$3,788
Costs and expenses	(816)	(2,484)	(1,206)	(3,584)
Income from continuing operations	102	122	238	204
Net income	100	102	200	170

13. New Accounting Pronouncements Not Yet Adopted

Business Combinations

In July 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 141, *Business Combinations*. This statement requires that all transactions that fit the definition of a business combination be accounted for using the purchase method and prohibits the use of the pooling of interests method for all business combinations initiated after June 30, 2001. This statement also establishes specific criteria for the recognition of intangible assets separately from goodwill and requires unallocated negative goodwill to be written off immediately as an extraordinary item. This standard will have an impact on any business combination we undertake in the future. We are currently evaluating the effects of this pronouncement on our historical financial statements.

Goodwill and Other Intangible Assets

In July 2001, the FASB issued SFAS No. 142, *Goodwill and Other Intangible Assets*. This statement requires that goodwill no longer be amortized but intermittently tested for impairment at least on an annual basis. Other intangible assets are to be amortized over their useful life and reviewed for impairment in accordance with the provisions of SFAS No. 121, *Accounting for the Impairment of Long-Lived Assets and Long-Lived Assets to be Disposed of*. An intangible asset with an indefinite useful life can no longer be amortized until its useful life becomes determinable. This statement has various effective dates, the most significant of which is January 1, 2002. We are currently evaluating the effects of this pronouncement.

Accounting for Asset Retirement Obligations

In July 2001, the FASB approved for issuance SFAS No. 143, *Accounting for Asset Retirement Obligations*. This statement requires companies to record a liability relating to the retirement and removal of assets used in their business. The liability is discounted to the present value, and the related asset value is increased by the amount of the resulting liability. Over the life of the asset, the liability will be accreted to its future value and eventually extinguished when the asset is taken out of service. The provisions of this statement are effective for fiscal years beginning after June 15, 2002. We are currently evaluating the effects of this pronouncement.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations[1]

The information contained in Item 2 updates, and you should read it in conjunction with, information disclosed in our amended Current Report on Form 8-K/A filed May 17, 2001, in addition to the financial statements and notes presented in Item 1, Financial Statements, of this Quarterly Report on Form 10-Q.

Recent Developments

Merger with The Coastal Corporation

In January 2001, we merged with Coastal. We accounted for the merger as a pooling of interests and converted each share of Coastal common stock and Class A common stock on a tax-free basis into 1.23 shares of our common stock. We also exchanged Coastal's outstanding convertible preferred stock for our common stock on the same basis as if the preferred stock had been converted into Coastal common stock immediately prior to the merger. We issued a total of approximately 271 million shares, including 4 million shares issued to holders of Coastal stock options. The discussion and analysis of our financial condition and results of operations reflects the combined information of our two companies for all periods presented.

Merger-Related Costs, Asset Impairments, and Other Charges

During the quarters and six months ended June 30, 2001 and 2000, we incurred charges that had a significant impact on our results of operations, financial position, and cash flows, and that are not expected to continue. These charges include those primarily related to our merger with Coastal, asset impairments, and other charges as follows:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2001	2000	2001	2000
	(In millions)			
Merger-related costs	$494	$49	$1,655	$53
Asset impairments	107	—	107	—
Total merger-related costs and asset impairments	601	49	1,762	53
Other charges	204	—	204	—
	$805	$49	$1,966	$53

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[1] Below is a list of terms that are common to our industry and used throughout our Management's Discussion and Analysis:

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

Merger-related costs include employee severance, retention, and transition charges; write-offs and write-downs of assets; charges to relocate assets and employees and consolidate operations; contract termination charges; and other charges. Although we expect to incur additional merger-related charges during the remainder of 2001, we do not expect the level of charges to be as high as those incurred during the first and second quarters of 2001.

Asset impairments include non-merger related write-downs of our investments in an international power project, as well as corporate-owned, private equity investments. These write-downs were a result of weak economic conditions causing a permanent decline in the value of these investments.

Other charges consist of changes in estimates of our environmental remediation obligations and the usability of spare parts inventories in our operations. These charges were necessitated by an ongoing evaluation of our operating standards and plans following the Coastal merger.

Each of these charges is discussed more fully in Item 1, Financial Statements, Notes 3 and 4. By segment, these charges were recorded as follows:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2001	2000	2001	2000
	(In millions)			
Merger-related costs, asset impairments, and other charges				
Pipelines	$246	$—	$ 335	$—
Merchant Energy	131	—	267	—
Production	7	—	70	—
Field Services	10	—	39	—
Segment total	394	—	711	—
Corporate and other	411	49	1,255	53
Consolidated total	$805	$49	$1,966	$53

Results of Operations

For the quarter ended June 30, 2001, we had a net loss of $93 million versus net income of $261 million for the quarter ended June 30, 2000. The 2001 loss was a result of merger-related costs, asset impairments, and other charges discussed above totaling $805 million, or $547 million after taxes. In addition, we recorded net extraordinary gains totaling $41 million, net of income taxes, as a result of FTC ordered sales of our Midwestern Gas Transmission system and our investments in the U-T Offshore and Iroquois pipeline systems. During the second quarter of 2000, merger-related costs were $49 million, or $33 million net of income taxes. Net income, excluding the effects of these charges and extraordinary items, would have been $413 million in 2001 versus $294 million in 2000, or an increase of 40 percent.

For the six months ended June 30, 2001, we had a net loss of $493 million versus net income of $689 million for the six months ended June 30, 2000. The 2001 loss was a result of merger-related costs, asset impairments, and other charges totaling $1,966 million, or $1,437 million after taxes. In addition, we recorded net extraordinary gains totaling $31 million, net of income taxes, as a result of FTC ordered sales of our Gulfstream pipeline project and Midwestern Gas Transmission system, and our investments in the Empire State, Stingray, U-T Offshore, and Iroquois pipeline systems. For the six months ended June 30, 2000, merger-related charges were $53 million, or $36 million net of income taxes, and we recorded extraordinary gains on FTC ordered sales of our East Tennessee and Sea Robin pipeline systems totaling $89 million, net of income taxes. Net income, excluding the after-tax effects of these charges and extraordinary items, would have been $913 million in 2001 versus $636 million in 2000, or an increase of 44 percent.

For the quarter ended June 30, 2001, our earnings before interest expense and income taxes (EBIT) was $150 million in 2001 versus $684 million in 2000. Excluding merger-related costs, asset impairments, and other charges mentioned above, adjusted EBIT would have been $955 million in 2001 versus $733 million in

2000, or an increase of 30 percent. Adjusted EBIT from the non-regulated segments of our business, which includes our Merchant Energy, Production, and Field Services segments, totaled 67 percent of all operating segments, with our Pipelines segment contributing 33 percent of the total.

For the six months ended June 30, 2001, EBIT was $82 million in 2001 versus $1,449 million in 2000. Excluding merger-related costs, asset impairments, and other charges, adjusted EBIT would have been $2,048 million in 2001 versus $1,502 million in 2000, or an increase of 36 percent. Adjusted EBIT from the non-regulated segments of our business, which included our Merchant Energy, Production, and Field Services segments, totaled 64 percent of all operating segments, with our Pipelines segment contributing 36 percent of the total.

Segment Results

Our business activities are segregated into four segments: Pipelines, Merchant Energy, Production, and Field Services. These segments are strategic business units that offer a variety of different energy products and services and each requires different technology and marketing strategies. These segments are consistent with those reported by us prior to our merger with Coastal. Coastal's historical segments (natural gas systems; refining, marketing, and chemicals; exploration and production; power; and coal) have been included in the segments in which these businesses are being operated in the combined company, and all prior periods have been restated to reflect this presentation. The results presented in this analysis are not necessarily indicative of the results that would have been achieved had this business segment structure been in place during those periods. Operating revenues and expenses by segment include intersegment revenues and expenses which are eliminated in consolidation. Because changes in energy commodity prices have a similar impact on both our operating revenues and cost of products sold from period to period, we believe that gross margin (revenue less cost of sales) provides a more accurate and meaningful basis for analyzing operating results for the trading and refining portions of Merchant Energy and the Field Services segment. For a further discussion of our individual segments, see Item 1, Financial Statements, Note 11. The segment results presented below include merger-related costs, asset impairments, and other charges as discussed above:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2001	2000	2001	2000
	(In millions)			
Earnings Before Interest Expense and Income Taxes				
Pipelines	$ 69	$295	$ 402	$ 685
Merchant Energy	134	245	392	397
Production	289	169	474	323
Field Services	55	52	91	108
Segment total	547	761	1,359	1,513
Corporate and other, net	(397)	(77)	(1,277)	(64)
Consolidated EBIT	$ 150	$684	$ 82	$1,449

Pipelines

Our Pipelines segment operates our interstate pipeline businesses. Each pipeline system operates under a separate tariff that governs its operations and rates. Operating results for our pipeline systems have generally been stable because the majority of the revenues are based on fixed reservation charges. As a result, we expect changes in this aspect of our business to be primarily driven by regulatory actions and contractual events. Commodity or throughput-based revenues account for a smaller portion of our operating results. These revenues vary from period to period, and system to system, and are impacted by factors such as weather, operating efficiencies, competition from other pipelines, and fluctuations in natural gas prices. Results of operations of the Pipelines segment were as follows for the periods ended June 30:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2001	2000	2001	2000
	(In millions, except volume amounts)			
Operating revenues	$ 652	$ 609	$ 1,444	$ 1,348
Operating expenses	(621)	(354)	(1,119)	(739)
Other income	38	40	77	76
EBIT	$ 69	$ 295	$ 402	$ 685
Throughput volumes (BBtu/d)[(1)]				
TGP	4,092	4,012	4,566	4,426
EPNG	4,552	4,000	4,688	3,969
ANR	3,776	3,823	3,857	3,860
CIG	2,284	1,941	2,357	2,044
SNG	1,657	2,037	1,943	2,227
Equity investments (our proportional share)	2,118	1,999	2,056	2,110
Total throughput	18,479	17,812	19,467	18,636

(1) Throughput volumes exclude those related to pipeline systems sold in connection with our Coastal and Sonat mergers including the Midwestern Gas Transmission, East Tennessee Natural Gas, and Sea Robin systems, and the Empire State, and Iroquois investments.

Second Quarter 2001 Compared to Second Quarter 2000

Operating revenues for the quarter ended June 30, 2001, were $43 million higher than the same period in 2000. The increase was primarily a result of higher transportation and storage revenues due to completed system expansions and new storage and transportation contracts during 2001, higher reservation revenues on the EPNG system as a result of a larger portion of its capacity earning maximum tariff rates versus the same period in 2000, higher throughput from increased deliveries to California and other western states, and the impact of higher natural gas prices on sales of production, sales of excess natural gas, and sales under natural gas sales contracts. Partially offsetting this increase were lower 2001 revenues resulting from contract remarketing during 2000 and the impact of the sale of the Midwestern Gas Transmission system in April 2001.

Operating expenses for the quarter ended June 30, 2001, were $267 million higher than the same period in 2000 primarily as a result of merger-related charges incurred in 2001, including costs related to facility consolidations and closures, costs to write-off assets whose value was impaired as a result of strategic decisions in the combined company, merger-related employee benefits and severance costs, and other merger charges. Also contributing to the increase were higher natural gas prices under natural gas purchase contracts, and higher fuel usage costs. Partially offsetting the increase were lower operating expenses due to cost efficiencies following the merger and reduced operating and depreciation expenses due to the sale of the Midwestern Gas Transmission system in April 2001.

Six Months Ended 2001 Compared to Six Months Ended 2000

Operating revenues for the six months ended June 30, 2001, were $96 million higher than the same period in 2000. The increase was a result of higher transportation and storage revenues due to completed system expansions and new storage and transportation contracts during 2001, higher reservation revenues on the EPNG system as a result of a larger portion of its capacity earning maximum tariff rates versus the same period in 2000, higher throughput from increased deliveries to California and other western states, and the impact of higher natural gas prices on sales of production, sales of excess natural gas and sales under natural gas sales contracts. Partially offsetting the increase were lower 2001 revenues resulting from contract remarketing during 2000 and the impact of the sale of Midwestern in April 2001 and the sales of the East Tennessee Natural Gas and Sea Robin systems in the first quarter of 2000.

Operating expenses for the six months ended June 30, 2001, were $380 million higher than the same period in 2000 primarily as a result of merger-related charges in 2001, including costs related to facility consolidations and closures, costs to write-off assets whose value was impaired as a result of strategic decisions in the combined company, merger-related employee benefits and severance costs, and other merger charges. Also contributing to the increase were higher natural gas prices under natural gas purchase contracts, higher fuel usage costs, and higher depreciation in 2001 as a result of the approval to reactivate the Elba Island facility during the first quarter of 2000 and additions of capital projects. Partially offsetting the increase were lower operating expenses due to cost efficiencies following the merger and reduced operating and depreciation expenses due to the sales of Midwestern in April 2001 and East Tennessee and Sea Robin in the first quarter of 2000.

Merchant Energy

Merchant Energy is involved in a wide range of activities in the wholesale energy marketplace, including trading and risk management, asset ownership, and financial services. Each market served by Merchant Energy is highly competitive and is influenced directly or indirectly by energy market economics. Prior to October 2000, Coastal conducted its marketing and trading activities through Engage Energy US, L.P. and Engage Energy Canada, L.P., a joint venture between Coastal and Westcoast Energy Inc., a Canadian natural gas company. During the fourth quarter of 2000, Coastal terminated the Engage joint venture and commenced its own marketing and trading activities.

Merchant Energy's trading and risk management activities provide energy trading and energy management solutions for its customers and affiliates involving such energy commodities as natural gas, power, crude oil, refined products, chemicals, and coal. The segment maintains a substantial trading portfolio that manages its risk across multiple commodities and over seasonally fluctuating energy demands.

Merchant Energy's asset ownership activities include ownership interests in 84 power plants in 20 countries and domestic and international refining, transportation, and chemical operations, as well as a 20 percent interest in Chaparral Investors, L.L.C., an entity established to acquire, hold, and manage domestic power generation assets. During the six month period ended June 30, 2001, Merchant Energy earned $74 million in fee-based revenues from Chaparral, and was reimbursed $10 million for operating expenses. For the six months ended June 30, 2000, fee-based revenues were $40 million, and expense reimbursements were $10 million.

In the financial services area, Merchant Energy owns EnCap Investments and Enerplus Global Energy Management, Inc., and conducts other energy financing activities. EnCap manages three separate oil and natural gas investment funds in the U.S., and serves as an investment advisor to one fund in Europe. EnCap also holds investments in emerging energy companies, and earns a return from these investments. In 2000, Merchant Energy acquired Enerplus, a Canadian investment management company, through which it conducts fund management activities similar to EnCap, but in Canada. Below are Merchant Energy's operating results and an analysis of these results for the periods ended June 30:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2001	2000	2001	2000
	(In millions, except volume amounts)			
Trading and refining gross margin	$ 349	$ 383	$ 868	$ 622
Operating and other revenues	150	135	342	268
Operating expenses	(515)	(369)	(1,057)	(674)
Other income	150	96	239	181
EBIT	$ 134	$ 245	$ 392	$ 397

	Quarter Ended June 30,		Six Months Ended June 30,	
	2001	2000	2001	2000
	(In millions, except volume amounts)			
Volumes				
Physical				
Natural gas (BBtue/d)	9,187	6,081	10,912	5,818
Power (MMWh)	44,538	22,412	80,026	46,148
Crude oil and refined products (MBbls)	166,546	165,195	335,783	328,883
Coal (MTons)	2,665	2,618	5,328	5,092
Financial settlements (BBtue/d)	186,860	118,301	217,060	128,625

Second Quarter 2001 Compared to Second Quarter 2000

Trading and refining gross margin consists of revenues from commodity trading and origination activities less the costs of commodities sold as well as revenues from refineries and chemical plants, less the cost of the feedstocks used in these refining processes. For the quarter ended June 30, 2001, these gross margins were $34 million lower than the same period in 2000. The decrease resulted from lower throughput at our refineries due to a fire at our Aruba facility in April 2001, as well as the lease of our Corpus Christi refinery to Valero in June 2001.

Merchant Energy is a provider of power and natural gas to the state of California. During the latter half of 2000 and continuing into 2001, California experienced sharp increases in natural gas prices and wholesale power prices due to energy shortages resulting from a combination of unusually warm summer weather followed by high winter demand, low gas storage levels, lower hydroelectric power generation, maintenance downtime of significant generation facilities, and price caps that discouraged power movement from other nearby states into California. The increase in power prices caused by the imbalance of natural gas and power supply and demand coupled with electricity price caps imposed on rates allowed to be charged to California electricity customers has resulted in large cash deficits of the two major California utilities, Southern California Edison and Pacific Gas and Electric. As a result, both utilities have defaulted on payments to creditors and have accumulated substantial under-collections from customers. This resulted in their credit ratings being downgraded in 2001 from above investment grade to below investment grade, and in April 2001, Pacific Gas and Electric filed for bankruptcy. Both utilities have filed for emergency rate increases with the CPUC and are working with the state authorities to restore the companies' financial viability. We have historically been one of the largest suppliers of energy to California, and we are actively participating with all parties in California to be a part of the long-term, stable solution to California's energy needs. We have established reserves that we believe are sufficient to cover our exposure to these issues. As a result, we do not believe, based on information known to date, these matters will have a material impact on our operating results.

Our investee, Chaparral, has ownership interests in 11 power plants in the state of California. As of June 30, 2001, customers of these facilities had only partially paid for power generated. This, coupled with Pacific Gas and Electric's bankruptcy declaration, has resulted in an event of default under the terms of each facility's loan agreement. Operations of these plants have been reduced, and each facility continues to take necessary actions to enforce the terms of its power purchase agreement. Management of Chaparral has indicated that it believes existing reserves against potential uncollectible accounts are adequate. We do not believe, based on information known to date, that these matters will have a material adverse impact on our operating results. However, our management fee from Chaparral is based on the value of its assets. As a result, if the value of these power plants is permanently reduced, it could have a similar effect on our management fee in future years.

Operating and other revenues consist of revenues from consolidated domestic and international power generation facilities, coal operations, and revenues from the financial services businesses of Merchant Energy. For the quarter ended June 30, 2001, operating and other revenues were $15 million higher than the same period in 2000. The increase resulted from higher management fees from Chaparral, revenues from the ManChief power project that commenced operations in July 2000, and revenues from the CEBU power project, a Philippine project in which we acquired an additional interest and began consolidating during the first quarter of 2001. Offsetting the increase were lower coal revenues due to a decrease in coal prices realized in the second quarter of 2001.

Operating expenses for the quarter ended June 30, 2001, were $146 million higher than the same period in 2000. The increase was primarily a result of merger-related costs and asset impairments associated with combining our merchant operations and implementing our combined strategy with Coastal, as well as increases in estimated environmental remediation costs and write-downs of spare parts inventory at our operating locations based on an ongoing evaluation of our operating standards and plans following the Coastal merger. Also contributing to the increase were higher professional fees and salaries resulting from the expansion of our operations in Europe and in our liquefied natural gas business and higher operating expenses from the consolidation of the CEBU power project.

Other income for the quarter ended June 30, 2001, was $54 million higher than the same period in 2000. The increase resulted from agency and marketing fees received in the second quarter of 2001 for a Brazilian power transaction, as well as increased equity earnings on unconsolidated power project investments.

Six Months Ended 2001 Compared to Six Months Ended 2000

Trading and refining gross margin for the six months ended June 30, 2001, was $246 million higher than the same period in 2000. The increase was primarily due to higher margins from natural gas trading activities in the first six months of 2001 resulting from increased trading volumes and price volatility, as well as increased refining margins in the first quarter largely due to higher prices received for refined products without a corresponding increase in feedstock prices. During the first six months of 2001, U.S. refining margins were at a level significantly higher than historical averages. We anticipate that these levels will be lower during the remainder of 2001.

Operating and other revenues for the six months ended June 30, 2001, were $74 million higher than the same period in 2000. The increase was a result of higher management fees from Chaparral, revenues on Enerplus which was acquired in August 2000, an increase in the value of Encap's investments, revenues from the ManChief power project that commenced operations in July 2000, and revenues from the CEBU power project, a Philippine project in which we acquired an additional interest and began consolidating during the first quarter of 2001.

Operating expenses for the six months ended June 30, 2001, were $383 million higher than the same period in 2000. The increase was primarily a result of merger-related costs and asset impairments associated with combining operations and implementing our combined strategy with Coastal and changes in our estimates of environmental remediation costs and spare parts inventory usability. Also contributing to the increase were higher professional fees and salaries resulting from the expansion of our operations into Europe and in our liquefied natural gas business and higher operating expenses from the consolidation of the CEBU power project.

Other income for the six months ended June 30, 2001, was $58 million higher than the same period in 2000. The increase was a result of a marketing and agency fee on a Brazilian power transaction in the second quarter of 2001, higher equity earnings on unconsolidated power project investments, and higher interest income resulting from increased broker-trading margin activity.

Production

Production's operating results are driven by a variety of factors including its ability to locate and develop economic gas and oil reserves, extract those reserves with minimal production costs, sell the products at attractive prices, and operate at the lowest cost level possible.

Production engages in hedging activities on its natural gas and oil production in order to stabilize cash flows and reduce the risk of downward commodity price movements on sales of its production. This is achieved through natural gas and oil swaps. We attempt to hedge approximately 75 percent of our anticipated current year production and approximately 50 percent of our anticipated succeeding year production. Production's hedge positions are closely monitored and evaluated in an effort to achieve its earnings objectives and reduce the risks associated with spot-market price volatility. Below are the operating results and an analysis of these results for the periods ended June 30:

	Quarter Ended		Six Months Ended	
	2001	2000	2001	2000
	(In millions, except volumes and prices)			
Natural gas	$ 486	$ 340	$ 952	$ 652
Oil, condensate, and liquids	77	65	163	127
Other	7	4	11	8
Total operating revenues	570	409	1,126	787
Operating expenses	(284)	(236)	(652)	(456)
Other income (loss)	3	(4)	—	(8)
EBIT	$ 289	$ 169	$ 474	$ 323
Volumes and prices				
Natural gas				
Volumes (MMcf)	139,277	132,833	273,221	259,154
Average realized prices ($/Mcf)	$ 3.49	$ 2.56	$ 3.49	$ 2.52
Oil, condensate and liquids				
Volumes (MBbls)	3,353	2,821	6,487	5,784
Average realized prices ($/Bbl)	$ 22.98	$ 23.09	$ 25.13	$ 22.02

Second Quarter 2001 Compared to Second Quarter 2000

For the quarter ended June 30, 2001, operating revenues were $161 million higher than the same period in 2000. The increase was the combined result of higher realized natural gas prices coupled with higher production. Realized natural gas sales prices were 36 percent higher than the second quarter of 2000, and natural gas production volumes rose during the second quarter 2001 by 5 percent over the same period in 2000. Oil, condensate, and liquids production volumes were 19 percent higher than the same period in 2000, with realized average prices slightly lower than 2000 levels.

Operating expenses for the quarter ended June 30, 2001, were $48 million higher than the same period in 2000 as a result of higher oilfield services costs, along with higher severance and other production taxes in 2001, which are generally tied to natural gas and oil prices, and write-downs of materials and supplies caused by the ongoing evaluation of our operating standards and plans in our combined production operations. Also contributing to the increase was higher depletion expense in 2001 as a result of the increased production volumes and higher capitalized costs in the full cost pool.

Six Months Ended 2001 Compared to Six Months Ended 2000

For the six months ended June 30, 2001, operating revenues were $339 million higher than the same period in 2000. The increase was the combined result of higher realized natural gas prices coupled with higher production. For the six months ended June 30, 2001, realized sales prices were 38 percent higher than the same period in 2000, and natural gas production volumes rose by 5 percent over the same period in 2000. Oil, condensate, and liquids production volumes were 12 percent higher than the same period in 2000, with average realized prices increasing 14 percent.

Operating expenses for the six months ended June 30, 2001, were $196 million higher than the same period in 2000 as a result of higher production costs due to increased oilfield services costs, and higher severance and other production taxes in 2001, which are generally tied to natural gas and oil prices, and merger-related costs and other charges related to our combined production operations. Also contributing to the increase was higher depletion expense in 2001 as a result of the increased production volumes and higher capitalized costs in the full cost pool.

Field Services

Field Services provides a variety of services for the midstream component of our operations, including gathering and treating of natural gas, processing and fractionation of natural gas, natural gas liquids and natural gas derivative products, such as ethane, propane, and butane. A subsidiary of Field Services also serves as the general partner of El Paso Energy Partners, a publicly traded master limited partnership. As the general partner, Field Services earns a combination of management fees and partner distributions for services rendered to Energy Partners. Field Services attempts to balance its earnings from its activities through a combination of fixed fee-based and market-based services.

Our gathering and treating operations earn margins substantially from fixed-fee based services; however, some of these operations earn margins from market-based rates. Revenues for these commodity rate services are the product of the market price, usually related to the monthly natural gas price index, and the volume gathered.

Processing and fractionation operations earn a margin based on fixed-fee contracts, percentage-of-proceeds contracts, and make-whole contracts. Percentage-of-proceeds contracts allow us to retain a percentage of the product as a fee for processing or fractionation service. Make-whole contracts allow us to retain the extracted liquid products and return to the producer a Btu equivalent amount of natural gas. Under our percentage-of-proceeds contracts and make-whole contracts, Field Services may have more sensitivity to price changes during periods when natural gas and natural gas liquids prices are volatile.

Field Services' operating results and an analysis of these results are as follows for the periods ended June 30:

	Quarter Ended		Six Months Ended	
	2001	2000	2001	2000
	(In millions, except volumes and prices)			
Gathering and treating margin	$ 72	$ 53	$ 155	$ 111
Processing margin	64	48	127	92
Other margin	9	(5)	13	6
Total gross margin	145	96	295	209
Operating expenses	(105)	(56)	(235)	(127)
Other income	15	12	31	26
EBIT	$ 55	$ 52	$ 91	$ 108
Volumes and prices				
Gathering and treating				
Volumes (BBtu/d)	8,968	5,582	8,699	5,516
Prices ($/MMBtu)	$ 0.12	$ 0.15	$ 0.13	$ 0.15
Processing				
Volumes (inlet BBtu/d)	4,340	3,098	4,117	3,011
Prices ($/MMBtu)	$ 0.16	$ 0.17	$ 0.17	$ 0.17

Second Quarter 2001 Compared to Second Quarter 2000

Total gross margin for the quarter ended June 30, 2001, was $49 million higher than the same period in 2000. The increase was a result of higher gathering and treating margins, which increased approximately 36 percent, primarily due to higher volumes as a result of our acquisition of PG&E's Texas Midstream operations in December 2000. Processing margins in 2001 were also higher, increasing 33 percent over 2000, as a result of contributions from the processing operations acquired from PG&E and higher natural gas and natural gas liquids prices in the San Juan Basin.

Operating expenses for the quarter ended June 30, 2001, were $49 million higher than the same period in 2000. The increase was a result of higher operating costs and depreciation expenses from the addition of PG&E's Texas Midstream operations and merger-related costs arising from commitments made related to FTC ordered sales of assets owned by Energy Partners, merger-related employee benefits and severance costs, and other merger charges.

Other income for the quarter ended June 30, 2001, was $3 million higher than the same period in 2000. The increase was a result of higher earnings in 2001 from our interests in Energy Partners, partially offset by equity investment losses from our Aux Sable liquids and Mobile Bay processing facilities.

Six Months Ended 2001 Compared to Six Months Ended 2000

Total gross margin for the six months ended June 30, 2001, was $86 million higher than the same period in 2000. The increase was a result of higher gathering and treating margins, which increased approximately 40 percent, primarily due to higher San Juan gathering rates, along with higher volumes as a result of our acquisition of PG&E's Texas Midstream operations in December 2000. Processing margins in 2001 were also higher, increasing 38 percent over 2000, as a result of contributions from the processing operations acquired from PG&E and higher natural gas and natural gas liquids prices in the San Juan Basin.

Operating expenses for the six months ended June 30, 2001, were $108 million higher than the same period in 2000. The increase was a result of higher operating costs and depreciation expenses from the addition of PG&E's Texas Midstream operations and merger-related costs arising from commitments made related to FTC ordered sales of assets owned by Energy Partners, merger-related employee benefits and severance, and other merger charges.

Other income for the six months ended June 30, 2001, was $5 million higher than the same period in 2000. The increase was a result of higher earnings in 2001 from our interests in Energy Partners, partially offset by our 2000 gains on the sales of the Colorado dry gathering system and equity investment losses from our Aux Sable liquids and Mobile Bay processing facilities.

Corporate and Other, net

Second Quarter 2001 Compared to Second Quarter 2000

Corporate expenses, which include results from our retail gas stations and telecommunications businesses for the quarter ended June 30, 2001, were $320 million higher than the same period 2000. The increase was primarily a result of merger-related charges in connection with our January 2001 merger with Coastal, costs associated with increased estimates of environmental remediation costs and usability of spare parts inventories in our corporate operations based on an ongoing evaluation of our operating standards and plans following the Coastal merger, and lower margins due to the sale of over 300 retail gas stations in 2001. Operating losses associated with our telecommunications business during the second quarter of 2001 were approximately $23 million.

Six Months Ended 2001 Compared to Six Months Ended 2000

Corporate expenses for the six months ended June 30, 2001, were $1,213 million higher than the same period in 2000. The increase was primarily a result of merger-related charges in connection with our January 2001 merger with Coastal, costs associated with increased estimates of environmental remediation costs and usability of spare parts inventories in our corporate operations based on an ongoing evaluation of our operating standards and plans following the Coastal merger, and lower margins due to the sale of over 300 retail gas stations in 2001. Operating losses associated with our telecommunications business for this period were approximately $28 million.

Interest and Debt Expense

Interest and debt expense for the quarter and six months ended June 30, 2001, was $42 million and $102 million higher than the same periods in 2000. The increase was a result of higher average borrowings in

2001 for ongoing capital projects, investment programs, and operating requirements. We also had an increase in short-term borrowings related to our revolving credit facility. We anticipate interest and debt expense will continue to exceed last year's levels throughout the remainder of 2001.

Minority Interest

Minority interest for the quarter and six months ended June 30, 2001, was $7 million and $27 million higher than the same periods in 2000 due to the sale of preferred interests in Clydesdale Associates, L.P. in May and December 2000.

For a further discussion of our borrowing and other financing activities during the period, see Part I, Item I, Financial Statements, Note 9.

Income Taxes

The income tax benefits for the quarter and six months ended June 30, 2001, were $63 million and $98 million, resulting in effective tax rates of 32 percent and 16 percent. Our effective tax rates were different than the statutory rate of 35 percent primarily due to the following:

- the non-deductible portion of merger-related costs and, for the six months ended June 30, 2001, other tax adjustments to provide for revised estimated liabilities;
- state income taxes;
- earnings from unconsolidated affiliates where we anticipate receiving dividends; and
- foreign income not taxed in the U.S., but taxed at foreign rates.

The income tax expenses for the quarter and six months ended June 30, 2000, were $125 million and $274 million, resulting in effective tax rates of 32 percent and 31 percent. Our effective tax rates were different than the statutory rate of 35 percent primarily due to the following:

- state income taxes;
- earnings from unconsolidated affiliates where we anticipate receiving dividends; and
- foreign income not taxed in the U.S., but taxed at foreign rates.

Liquidity and Capital Resources

Cash From Operating Activities

Net cash provided by our operating activities was $2,554 million for the six months ended June 30, 2001, compared to net cash used of $77 million for the same period of 2000. The increase was primarily due to liquidations of net derivative trading positions during the first half of 2001, coupled with the impact of lower commodity prices. Partially offsetting these increases were cash payments in 2001 for charges related to the merger with Coastal and higher interest payments.

Cash From Investing Activities

Net cash used in our investing activities was $1,654 million for the six months ended June 30, 2001. Our investing activities principally consisted of additions to property, plant, and equipment, including an increase in our oil and natural gas properties for developmental drilling, and expenditures for expansion and construction projects. We also had additions to joint ventures and investments in unconsolidated affiliates, primarily related to our investment in two international power companies located in Brazil and China, and additions of short-term notes from unconsolidated affiliates. Cash inflows from investment-related activities included proceeds from the sales of our Midwestern Gas Transmission system, our Gulfstream pipeline project, and our interests in the Empire State and Iroquois pipeline systems, along with proceeds from the sales of over 300 of our retail gas stations.

In August 2001, we completed the acquisition of Velvet Exploration Ltd., at a cost of approximately $230 million (approximately C$353 million). Velvet is a Canadian exploration and development company, with properties located in the Foothills and Deep Basin areas of western Alberta Province.

Cash From Financing Activities

Net cash used in our financing activities was $588 million for the six months ended June 30, 2001. During 2001, we repaid short-term borrowings and notes to unconsolidated affiliates, retired long-term debt, and paid dividends. Cash provided from our financing activities included the issuance of long-term debt and issuances of common stock as a result of the exercise of employee stock options.

We expect that future funding for working capital needs, capital expenditures, acquisitions, other investing activities, long-term debt retirements, payments of dividends and other financing expenditures will be provided by internally generated funds, commercial paper issuances, available capacity under existing credit facilities, and the issuance of new long-term debt, trust securities, or equity.

The following table reflects quarterly dividends declared and paid on our common stock:

Declaration Date	Amount Per Common Share	Payment Date	Total Amount
			(In millions)
Coastal			
November 1, 2000	$0.0625	January 1, 2001	$ 13
El Paso			
October 26, 2000	$0.2060	January 2, 2001	$ 49
January 24, 2001	$0.2125	April 2, 2001	$108
April 17, 2001	$0.2125	July 2, 2001	$108

In July 2001, we declared a quarterly dividend of $0.2125 per share on our common stock, payable on October 1, 2001, to stockholders of record on September 7, 2001. Also, during the six months ended June 30, 2001, we paid dividends of $12 million on the 8¼% Series A cumulative preferred stock of our subsidiary, El Paso Tennessee Pipeline Co.

Commitments and Contingencies

See Item 1, Financial Statements, Note 10, which is incorporated herein by reference.

New Accounting Pronouncements Not Yet Adopted

See Item 1, Financial Statements, Note 13, which is incorporated herein by reference.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

We have made statements in this document that constitute forward-looking statements, as that term is defined in the Private Securities Litigation Reform Act of 1995. These statements are subject to risks and uncertainties. Forward-looking statements include information concerning possible or assumed future results of operations. These statements may relate to information or assumptions about:

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

Important factors that could cause actual results to differ materially from estimates or projections contained in forward-looking statements include, among others, the following:

- the ability to successfully integrate Coastal's operations and PG&E's Texas Midstream operations;
- the increasing competition within our industry;
- the timing and extent of changes in commodity prices for natural gas and power;
- the uncertainties associated with customer contract expirations on our pipeline systems;
- the potential contingent liabilities and tax liabilities related to our acquisitions;
- the potential contingent liabilities, sanctions, or business restrictions in connection with the energy crisis in California;
- the political and economic risks associated with current and future operations; and
- the conditions of equity and other capital markets.

These risk factors are more fully described in our other filings with the Securities and Exchange Commission, including our Current Report on Form 8-K/A filed on May 17, 2001.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

There are no material changes in our quantitative and qualitative disclosures about market risks from those reported in our Current Report on Form 8-K/A filed on May 17, 2001.

PART II — OTHER INFORMATION

Item 1. Legal Proceedings

See Part I, Item 1, Financial Statements, Note 10, which is incorporated herein by reference.

The eleven *Carlsbad* lawsuits are as follows: three were filed in district court in Harris County, Texas (*Diane Heady, et al v. El Paso Energy Corporation (EPEC) and EPNG,* filed September 7, 2000, and settled in March 2001; *Richard Heady, et al v. EPEC and EPNG,* filed February 15, 2001, and settled in March 2001; and *Geneva Smith, et al v. EPEC and EPNG,* filed October 23, 2000), two were filed in federal district court in Albuquerque, New Mexico (*Dawson, as Personal Representative of Kirsten Janay Sumler, v. EPEC and EPNG,* filed November 8, 2000, and *Jennifer Smith, et al v. EPEC and EPNG,* filed August 29, 2000, and settled in June 2001), and six were filed in state district court in Carlsbad, New Mexico (*Chapman, as Personal Representative of the Estate of Amy Smith Heady, v. EPEC, EPNG, and John Cole,* filed February 9, 2001; and *Chapman, as Personal Representative of the Estate of Dustin Wayne Smith, v. EPEC, EPNG and John Cole; Chapman, as Personal Representative of the Estate of Terry Wayne Smith, v. EPNG, EPEC, and John Cole; Green, as Personal Representative of the Estate of Jesse Don Sumler, v. EPEC, EPNG, and John Cole; Rackley, as Personal Representative of the Estate of Glenda Gail Sumler, v. EPEC, EPNG, and John Cole;* and *Rackley, as Personal Representative of the Estate of Amanda Sumler Smith, v. EPEC, EPNG, and John Cole,* all filed March 16, 2001).

The alleged five probable violations of the regulations of the Department of Transportation's Office of Pipeline Safety are: 1) failure to perform appropriate tasks to prevent corrosion, with an associated proposed fine of $500,000; 2) failure to investigate and minimize internal corrosion, with an associated proposed fine of $1,000,000; 3) failure to consider unusual operating and maintenance conditions and respond appropriately, with an associated proposed fine of $500,000; 4) failure to follow company procedures, with an associated proposed fine of $500,000; and 5) failure to maintain topographical diagrams, with an associated proposed fine of $25,000.

The *California* cases are: four filed in the Superior Court of Los Angeles County (*Continental Forge Company, et al v. Southern California Gas Company, et al,* filed September 25, 2000; *Berg v. Southern California Gas Company, et al;* filed December 18, 2000; *The City of Los Angeles, et al v. Southern California Gas Company, et al* and *The City of Long Beach, et al v. Southern California Gas Company, et al,* both filed March 20, 2001); two filed in the Superior Court of San Diego County (*John W.H.K. Phillip v. El Paso Merchant Energy* and *John Phillip v. El Paso Merchant Energy,* both filed December 13, 2000); and three filed in the Superior Court of San Francisco County (*Sweetie's, et al v. El Paso Corporation, et al,* filed March 22, 2001; *Philip Hackett, et al v. El Paso Corporation, et al,* filed May 9, 2001; and *California Dairies, Inc., et al v. El Paso Corporation, et al,* filed May 21, 2001). The four cases filed in 2000 were the cases consolidated for pretrial activities.

Item 2. Changes in Securities and Use of Proceeds

None.

Item 3. Defaults Upon Senior Securities

None.

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

We held our annual meeting of stockholders on May 21, 2001. Proposals presented for a stockholders' vote included the election of twelve directors, the adoption of two equity plans, the ratification of the appointment of PricewaterhouseCoopers LLP as independent certified public accountants for the fiscal year 2001, and one stockholder proposal.

Each of the twelve incumbent directors nominated by El Paso was elected with the following voting results:

	For	Withheld
Byron Allumbaugh	443,566,565	4,173,138
David A. Arledge	442,976,363	4,763,340
John M. Bissel	443,258,908	4,480,795
Juan Carlos Braniff	443,651,714	4,087,989
James F. Gibbons	443,718,862	4,020,841
Anthony W. Hall, Jr.	443,612,529	4,127,174
Ronald L. Kuehn, Jr.	443,471,984	4,267,719
J. Carlton MacNeil, Jr.	443,737,742	4,001,961
Thomas R. McDade	443,649,037	4,090,666
Malcolm Wallop	443,289,164	4,450,540
William A. Wise	388,115,277	59,624,426
Joe B. Wyatt	443,568,172	4,171,531

There were no broker non-votes for the election of directors.

Two proposals were presented for a stockholder vote. One proposal was to approve the El Paso Corporation 2001 Omnibus Incentive Compensation Plan, and the second proposal was to approve the El Paso Corporation 2001 Stock Option Plan for Non-Employee Directors. The proposals were approved with the following voting results:

	For	Against	Abstain
Approval of the El Paso Corporation 2001 Omnibus Incentive Compensation Plan	306,489,989	138,424,711	2,825,003
Approval of the El Paso Corporation 2001 Stock Option Plan for Non-Employee Directors	324,334,657	120,367,374	3,037,673

There were no broker non-votes on the proposals.

The appointment of PricewaterhouseCoopers LLP as the Company's independent certified public accountants for the fiscal year 2001 was ratified with the following voting results:

	For	Against	Abstain
Ratification of the appointment of PricewaterhouseCoopers LLP	442,538,789	3,265,699	1,935,215

There were no broker non-votes for the ratification of PricewaterhouseCoopers LLP.

One proposal submitted by a stockholder was presented for a stockholder vote. The proposal was the adoption by the Board of Directors of a resolution requiring the Governance Committee to nominate two candidates for each directorship to be filled by voting of stockholders at annual meetings, and in addition to the customary personal background information, the Proxy Statement shall include a statement by each candidate as to why he or she believes they should be elected. The proposal was not approved with the following voting results:

	For	Against	Abstain
Approval of the stockholder proposal to revise the procedure for the election of directors	15,980,055	375,536,401	8,211,922

There were 48,011,324 broker non-votes on the stockholder proposal.

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 asterisk; all exhibits not so designated are incorporated herein by reference to a prior filing as indicated.

Exhibit Number		Description
*10.A	—	$3,000,000,000, 364-Day Revolving Credit and Competitive Advance Facility Agreement, dated as of June 11, 2001, by and among El Paso Corporation, El Paso Natural Gas Company, Tennessee Gas Pipeline Company, the several banks and other financial institutions from time to time parties to the Agreement, The Chase Manhattan Bank, ABN Amro Bank, N.V., and Citibank, N.A., as co-documentation agents for the Lenders, and Bank of America, N.A. and Credit Suisse First Boston, as co-syndication agents for the Lenders.
10.AA	—	2001 Stock Option Plan for Non-Employee Directors, effective as of January 29, 2001. (Exhibit 10.1 to our Form S-8 filed June 29, 2001.)
10.BB	—	2001 Omnibus Incentive Compensation Plan, effective as of January 29, 2001. (Exhibit 10.1 to our Form S-8 filed June 29, 2001.)

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

We filed a current report on Form 8-K, dated May 14, 2001, announcing that we entered into an Underwriting Agreement with Salomon Smith Barney, Inc., BNP Paribas Securities Corp., BNY Capital Markets, Inc., TD Securities (USA) Inc., pursuant to which we issued $500 million aggregate principal amount of 7.0% Senior Notes due 2011.

We filed an amended current report on Form 8-K/A, dated May 17, 2001, to reflect the filing of our quarterly report on Form 10-Q for the period ended March 31, 2001. As a result of the filing of that quarterly report, the combined financial statements included in that report became our primary historical consolidated financial statements.

We filed a current report on Form 8-K, dated July 25, 2001, furnishing our Computation of Earnings to Fixed Charges for the five years ended December 31, 2000, and for the quarters ended March 31, 2000 and 2001.

We filed a current report on Form 8-K, dated July 30, 2001, to report that we entered into an agreement with J.P. Morgan Securities, Inc., ABN AMRO Incorporated and Banc of America Securities LLC, pursuant to which we issued $700 million aggregate principal amount of 7.80% medium term notes.

We filed a current report on Form 8-K/A, dated July 31, 2001, which amended the current report on Form 8-K, dated July 30, 2001, to provide additional information with respect to our use of proceeds from the 7.80% medium term notes offering.

SIGNATURES

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

EL PASO CORPORATION

Date: August 10, 2001

/s/ H. BRENT AUSTIN

H. Brent Austin
Executive Vice President and
Chief Financial Officer

Date: August 10, 2001

/s/ JEFFREY I. BEASON

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