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

Form 10-Q

(Mark One)

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

For the quarterly period ended September 30, 2000

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 Energy 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 Energy Building **1001 Louisiana Street** **Houston, Texas** (Address of Principal Executive Offices)	**77002** (Zip Code)

Registrant's Telephone Number, Including Area Code: **(713) 420-2131**

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 November 6, 2000: 233,968,803

PART I — FINANCIAL INFORMATION

Item 1. Financial Statements

EL PASO ENERGY CORPORATION

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

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2000	1999	2000	1999
Operating revenues	$6,987	$3,262	$14,320	$8,137
Operating expenses				
Cost of gas and other products	6,293	2,633	12,122	6,223
Operation and maintenance	214	250	650	719
Merger-related costs and asset impairment charges	—	58	46	193
Ceiling test charges	—	—	—	352
Depreciation, depletion, and amortization	150	145	443	434
Taxes, other than income taxes	34	32	111	108
	6,691	3,118	13,372	8,029
Operating income	296	144	948	108
Other income				
Equity investment earnings	63	33	101	82
Interest income	13	12	41	32
Net gain on sales of assets	4	1	28	23
Other, net	11	16	21	38
	91	62	191	175
Income before interest, income taxes, and other charges	387	206	1,139	283
Interest and debt expense	140	119	390	331
Minority interest	32	12	81	20
Income tax expense (benefit)	71	29	213	(23)
	243	160	684	328
Income (loss) before preferred dividends of subsidiary, extraordinary gain, and cumulative effect of accounting change	144	46	455	(45)
Preferred stock dividends of subsidiary	7	7	19	19
Income (loss) before extraordinary gain and cumulative effect of accounting change	137	39	436	(64)
Extraordinary gain, net of income taxes	—	—	89	—
Cumulative effect of accounting change, net of income taxes	—	—	—	(13)
Net income (loss)	$ 137	$ 39	$ 525	$ (77)
Comprehensive income (loss)	$ 132	$ 35	$ 518	$ (89)
Basic earnings per common share				
Income (loss) before extraordinary gain and cumulative effect of accounting change	$ 0.59	$ 0.17	$ 1.89	$(0.28)
Extraordinary gain, net of income taxes	—	—	0.39	—
Cumulative effect of accounting change, net of income taxes	—	—	—	(0.06)
Net income (loss)	$ 0.59	$ 0.17	$ 2.28	$(0.34)
Diluted earnings per common share				
Income (loss) before extraordinary gain and cumulative effect of accounting change	$ 0.57	$ 0.17	$ 1.83	$(0.28)
Extraordinary gain, net of income taxes	—	—	0.37	—
Cumulative effect of accounting change, net of income taxes	—	—	—	(0.06)
Net income (loss)	$ 0.57	$ 0.17	$ 2.20	$(0.34)
Basic average common shares outstanding	231	228	230	227
Diluted average common shares outstanding	244	231	242	227
Dividends declared per common share	$ 0.21	$ 0.20	$ 0.62	$ 0.60

See accompanying notes.

EL PASO ENERGY CORPORATION

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

	September 30, 2000	December 31, 1999
ASSETS		
Current assets		
Cash and cash equivalents	$ 169	$ 545
Accounts and notes receivable, net	3,099	1,662
Materials and supplies	76	74
Assets from price risk management activities	2,202	233
Other	311	397
Total current assets	5,857	2,911
Property, plant, and equipment, net	10,448	10,261
Investments in unconsolidated affiliates	2,809	2,029
Assets from price risk management activities	1,575	413
Other	1,057	1,043
Total assets	$21,746	$16,657
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Accounts and notes payable	$ 3,266	$ 1,658
Short-term borrowings (including current maturities of long-term debt)	1,825	1,344
Liabilities from price risk management activities	1,166	197
Other	999	499
Total current liabilities	7,256	3,698
Long-term debt, less current maturities	4,566	5,223
Noncurrent affiliated notes payable	425	—
Deferred income taxes	1,962	1,738
Liabilities from price risk management activities	790	95
Other	1,110	1,263
Commitments and contingencies		
Company-obligated preferred securities of El Paso Energy Capital Trust I and IV	625	325
Minority interest	1,581	1,368
Stockholders' equity		
Common stock, par value $3 per share; authorized 750,000,000 shares; issued 242,218,516 and 238,542,335 shares, respectively	727	716
Additional paid-in capital	1,480	1,367
Retained earnings	1,590	1,207
Accumulated other comprehensive income	(36)	(29)
Treasury stock (at cost); 8,558,324 and 8,947,565 shares, respectively	(269)	(273)
Deferred compensation	(61)	(41)
Total stockholders' equity	3,431	2,947
Total liabilities and stockholders' equity	$21,746	$16,657

See accompanying notes.

EL PASO ENERGY CORPORATION

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

	Nine Months Ended September 30, 2000	Nine Months Ended September 30, 1999
Cash flows from operating activities		
Net income (loss)	$ 525	$ (77)
Adjustments to reconcile net income (loss) to net cash from operating activities		
Depreciation, depletion, and amortization	443	434
Ceiling test charges	—	352
Deferred income tax expense (benefit)	234	(25)
Net gain on sale of assets	(28)	(23)
Undistributed earnings in equity investees	(65)	(58)
Non-cash portion of merger-related charges	—	121
Extraordinary gain on sales	(149)	—
Other	(15)	(4)
Change in price risk management activities	(1,467)	(248)
Other working capital changes, net of non-cash transactions	278	(49)
Other	(61)	(48)
Net cash provided by (used in) operating activities	(305)	375
Cash flows from investing activities		
Purchases of property, plant, and equipment	(992)	(719)
Net proceeds from the sale of assets	500	27
Additions to investments	(1,188)	(841)
Proceeds from the sale of investments	261	50
Change in cash deposited in escrow related to an equity investee	24	(101)
Repayment of notes receivable from Chaparral	647	—
Cash paid for acquisitions, net of cash received	(197)	(141)
Net cash used in investing activities	(945)	(1,725)
Cash flows from financing activities		
Net repayments of commercial paper and short-term notes	(121)	(296)
Revolving credit borrowings	545	532
Revolving credit repayments	(520)	(922)
Net proceeds from the issuance of long-term debt	—	1,781
Payments to retire long-term debt	(121)	(186)
Increase in notes payable to Chaparral	633	—
Increase (decrease) in notes payable to equity investees	(15)	101
Net proceeds from issuance of Company-obligated preferred securities of El Paso Energy Capital Trust IV	293	—
Net proceeds from issuance of minority interests in subsidiaries	245	493
Dividends paid	(140)	(160)
Other	75	16
Net cash provided by financing activities	874	1,359
Increase (decrease) in cash and cash equivalents	(376)	9
Cash and cash equivalents		
Beginning of period	545	104
End of period	$ 169	$ 113

See accompanying notes.

EL PASO ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

1. BASIS OF PRESENTATION

Our 1999 Annual Report on Form 10-K includes a summary of our significant accounting policies and other disclosures. You should read it in conjunction with this Quarterly Report on Form 10-Q. The condensed consolidated financial statements at September 30, 2000, and for the quarters and nine months ended September 30, 2000 and 1999, are unaudited. The condensed consolidated balance sheet at December 31, 1999, is derived from the audited financial statements. 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, 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 financial information for the quarter and nine months ended September 30, 1999, includes the combined historical results of El Paso Energy Corporation and Sonat Inc. to reflect our October 1999 merger with Sonat, which was accounted for as a pooling of interests. The prior period information also includes reclassifications which were made to conform to the current presentation. These reclassifications have no effect on our reported net income or stockholders' equity.

Ceiling Test Charges

Under the full cost method of accounting for natural gas and oil properties, we perform quarterly ceiling tests to ensure that the carrying value of natural gas and oil properties is not overstated. At March 31, 1999, our capitalized costs exceeded this ceiling test limit by $352 million. This write-down is included as ceiling test charges in our statements of income.

Cumulative Effect of Accounting Change

In the first quarter of 1999, we adopted the American Institute of Certified Public Accountants Statement of Position 98-5, *Reporting on the Costs of Start-Up Activities*. This statement required companies to expense start-up and organization costs as incurred and expense any such costs that existed on their balance sheet. We adopted the pronouncement effective January 1, 1999, and reported a charge of $13 million, net of income taxes, as a cumulative effect of an accounting change.

2. MERGERS AND ACQUISITIONS

Coastal

In January 2000, we entered into a definitive agreement to merge with The Coastal Corporation. In the merger, we will convert each share of Coastal's common stock and Class A common stock into 1.23 shares of our common stock. We will exchange Coastal's outstanding convertible preferred stock for our common stock on the same basis as if we had converted the preferred stock into Coastal's common stock immediately prior to the merger. At September 30, 2000, the total value of the transaction was approximately $23 billion, including $7 billion of assumed debt and preferred equity. We will account for the transaction as a pooling of interests. On May 5, 2000, Coastal's stockholders approved and adopted the merger agreement and our stockholders approved the issuance of the common shares in connection with the merger. On July 26, 2000, the Federal Energy Regulatory Commission (FERC) approved the merger. We expect the transaction to close in the fourth quarter of 2000 once we have received all necessary approvals, including the approval by the Federal Trade Commission (FTC).

Coastal is a diversified energy holding company. It is engaged, through its subsidiaries and joint ventures, in natural gas transmission, storage, gathering, processing and marketing; natural gas and oil exploration and production; and petroleum refining, marketing and distribution. It owns interests in approximately

18,000 miles of natural gas pipelines extending across the midwestern and the Rocky Mountain areas of the United States and has proved reserves of 3.6 Tcfe.

Texas Midstream Operations

In January 2000, we entered into an agreement to purchase the natural gas and natural gas liquids businesses of PG&E Gas Transmission, Texas Corporation, and PG&E Gas Transmission Teco, Inc. The value of the transaction is approximately $840 million, including assumed debt of $561 million. On October 25, 2000, we signed an FTC consent decree to allow us to complete this acquisition. As part of the normal review process, the consent decree must be approved by the FTC. We are also finalizing a similar agreement with the State of Texas. We expect both agreements to become final and the transaction to close in the fourth quarter of 2000. We will account for the transaction as a purchase and will include the acquired assets and operations in our Field Services segment. Some of these acquired operations may be appropriate for acquisition by El Paso Energy Partners, the master-limited partnership of which we are the general partner.

The businesses we are acquiring consist of 8,500 miles of intrastate natural gas transmission pipelines, nine natural gas processing plants that currently process 1.5 Bcf/d, and a 7.2 Bcf natural gas storage field. They also own significant natural gas liquids pipelines and fractionation facilities.

Merger Costs

As we complete our proposed Coastal and Texas Midstream transactions and begin to integrate the activities and operations of these businesses, we will incur transaction, severance, transition, and other merger-related charges that will have a significant impact on our results of operations and financial position. These costs may include, but are not limited to, write-offs or write-downs of duplicate assets, charges to relocate assets and employees, contract termination charges, and charges to align accounting policies and practices. During the third quarter of 2000, we announced a plan to combine our pipeline operations with Coastal's pipeline operations. Under the consolidation plan, El Paso Natural Gas Company's (EPNG) operations will be relocated from El Paso, Texas to Colorado Springs, Colorado, and ANR Pipeline Company, a subsidiary of Coastal, will be relocated from Detroit, Michigan, to Houston, Texas. In addition to merger-related charges, we will be required to sell assets as a condition of the FTC to completing these transactions.

Under current accounting rules, some of our merger-related costs will be accrued at the merger date, while others will be expensed as incurred. All accrued merger-related costs in a pooling of interests transaction, such as our proposed merger with Coastal, will be recorded in our results of operations. In a purchase transaction, such as our proposed Texas Midstream acquisition, these costs will be included as a component of our purchase price.

In October 2000, we entered into an agreement with a third-party to sell our interest in Oasis Pipeline Company. The sale is contingent upon the approval of the FTC and the Texas Attorney General. We expect to incur a loss on this transaction of approximately $20 million, net of income taxes. However, we do not expect this sale or any other required sales, individually or in total, to have a material adverse effect on our ongoing financial position, results of operations, or cash flows.

3. EXTRAORDINARY GAIN

During the first quarter of 2000, we sold East Tennessee Natural Gas Company and Sea Robin Pipeline Company to comply with an FTC order related to our merger with Sonat. Net proceeds from the sales were $457 million and we recognized an extraordinary gain of $89 million, net of income taxes of $60 million. In May 2000, we also disposed of our one-third interest in Destin Pipeline Company to comply with the same FTC order. Net proceeds from this sale were $159 million and no material gain or loss was recognized on the transaction.

4. EARNINGS PER SHARE

Our computations of basic and diluted earnings per common share are presented below.

	Quarter Ended September 30,			
	2000		1999	
	Basic	Diluted	Basic	Diluted[(1)]
	(In millions, except per common share amounts)			
Income before extraordinary gain and cumulative effect of accounting change	$ 137	$ 137	$ 39	$ 39
Interest on trust preferred securities	—	3	—	—
Adjusted net income	$ 137	$ 140	$ 39	$ 39
Average common shares outstanding	231	231	228	228
Effect of dilutive securities				
Restricted stock	—	—	—	—
Stock options	—	5	—	3
Trust preferred securities	—	8	—	—
Average common shares outstanding	231	244	228	231
Earnings per common share	$0.59	$0.57	$0.17	$0.17

(1) Adding trust preferred securities to potential average common shares outstanding would have increased earnings per share for the quarter ended September 30, 1999. Therefore, the trust preferred securities and the interest on these securities have not been factored into diluted earnings per share for this period.

	Nine Months Ended September 30,		
	2000		1999[(1)]
	Basic	Diluted	Basic
	(In millions, except per common share amounts)		
Income (loss) before extraordinary gain and cumulative effect of accounting change	$ 436	$ 436	$ (64)
Interest on trust preferred securities	—	8	—
Adjusted income (loss) before extraordinary gain and cumulative effect of accounting change	436	444	(64)
Extraordinary gain, net of income taxes	89	89	—
Cumulative effect of accounting change, net of income taxes	—	—	(13)
Adjusted net income (loss)	$ 525	$ 533	$ (77)
Average common shares outstanding	230	230	227
Effect of dilutive securities			
Restricted stock	—	—	—
Stock options	—	4	—
Trust preferred securities	—	8	—
Average common shares outstanding	230	242	227
Earnings per common share			
Adjusted income (loss) before extraordinary gain and cumulative effect of accounting change	$1.89	$1.83	$(0.28)
Extraordinary gain, net of income taxes	0.39	0.37	—
Cumulative effect of accounting change, net of income taxes	—	—	(0.06)
Net income (loss)	$2.28	$2.20	$(0.34)

(1) Adding potentially dilutive securities to average common shares outstanding for the nine months ended September 30, 1999, would have reduced the loss per share. Therefore, the diluted loss per share was not presented for that period.

5. PROPERTY, PLANT, AND EQUIPMENT

Our property, plant, and equipment consisted of the following at September 30, 2000 and December 31, 1999:

	2000	1999
	(In millions)	
Property, plant, and equipment, at cost		
Natural Gas Transmission	$ 7,903	$ 8,121
Merchant Energy	248	200
International	313	316
Field Services	1,269	1,220
Production	5,811	5,415
Corporate and other	235	196
	15,779	15,468
Less accumulated depreciation and depletion	7,699	7,656
	8,080	7,812
Additional acquisition cost assigned to utility plant, net of accumulated amortization	2,368	2,449
Total property, plant, and equipment, net	$10,448	$10,261

6. DEBT AND OTHER CREDIT FACILITIES

Since the beginning of 2000, we:

- established, borrowed and repaid $250 million under a non-committed line of credit;
- redeemed the Hattiesburg Gas Storage Company's 8.12% Secured Guaranteed Notes due 2005 in an aggregate principal amount of $36 million;
- formed the El Paso Energy Capital Trust IV, a Delaware statutory business trust, and issued $300 million variable rate preferred securities, as described in Note 11;
- established a $1 billion commercial paper program for El Paso Energy in addition to TGP's and EPNG's current programs;
- redeemed DeepTech's 12% Notes Due 2000, in an aggregate principal amount of $82 million;
- received funds, which were used to pay down short-term borrowings and for other corporate purposes, from Chaparral Investors as described in Note 9; and
- increased our credit facilities as described below.

In August 2000, we replaced our $1,250 million 364-day renewable revolving credit and competitive advance facility with a $2 billion facility and our $750 million 3-year revolving credit and competitive advance facility with a $1 billion facility. EPNG and Tennessee Gas Pipeline Company (TGP) are also designated borrowers under these new facilities. The interest rate for these facilities varies and would have been LIBOR plus 50 basis points on September 30, 2000. The available credit under these facilities is expected to be used for general corporate purposes including, but not limited to, supporting our commercial paper programs.

At September 30, 2000, our weighted average interest rate on short-term borrowings was 6.8% and at December 31, 1999, it was 6.6%. We had the following short-term borrowings, including current maturities of long-term debt, at September 30, 2000 and December 31, 1999:

	2000	1999
	(In millions)	
Commercial paper	$1,095	$1,217
Other credit facilities	60	35
Current maturities of long-term debt	945	92
	2,100	1,344
Reclassification to long-term debt	(275)	—
	$1,825	$1,344

In October 2000, we issued $300 million ($296 million, net of issuance costs) aggregate principal amount 8.05% medium-term notes due 2030. The proceeds were used to repay $275 million of commercial paper borrowings with the remainder used for other corporate purposes. As a result of this transaction, we classified $275 million of short-term borrowings as long-term debt in our September 30, 2000 balance sheet.

In November 2000, we terminated an interest rate swap with a notional amount of $600 million and a termination date of July 2001. The swap was originally put into place to swap the 6.625% fixed interest rate on our July 1999, $600 million aggregate principal Senior Notes due 2001 with a variable interest rate. The termination of the swap did not have a material impact on our financial results.

7. COMMITMENTS AND CONTINGENCIES

Rates and Regulatory Matters

Each of our pipeline systems has contracts covering a portion of its firm transportation capacity with various terms of maturity, and each operates in different markets and regions with different competitive and regulatory pressures which can impact its ability to renegotiate and renew existing contracts, or enter into new long-term firm transportation commitments. Currently, approximately 70 percent of TGP's capacity is subject to firm contracts, with an average term in excess of five years, that will expire after 2001. In March 2000, Southern Natural Gas Company (SNG) extended its firm transportation and storage contracts until 2005 or later, substantially all of which were at the maximum tariff rates allowed under its settlement. EPNG has 27 percent of its capacity subscribed under shorter-term contracts. On each of our pipeline systems, we are aggressively pursuing the renegotiation and renewal of expiring contracts, and the sale of excess capacity under firm transportation arrangements. However, we are uncertain if future contracts will be on terms as favorable to us as those that currently exist. Also, customers and other groups may dispute new or renewed contracts. As a result, we cannot be sure that regulators or other jurisdictional bodies will not intercede in our re-contracting process and alter the ultimate outcome of our efforts.

All of EPNG's customers who were parties to its rate case settlement participate in risk sharing provisions under the settlement. As of September 30, 2000, EPNG had unearned risk sharing revenues of $104 million and had $43 million remaining to be collected from customers under this provision. If revenue from remarketing its relinquished capacity to customers exceeds certain dollar levels specified in the risk sharing agreement, EPNG may be obligated to refund a portion of the excess to customers. Under this provision, EPNG refunded $15 million for 1999 revenues to customers and, as of September 30, 2000, has reserved $9 million against 2000 revenues. The risk sharing provisions of the rate settlement extend through 2003, at which time EPNG will be at risk for all unsubscribed, excess capacity on its system.

As changes in the regulatory and economic environment evolve and our pipelines continue to experience discounting of rates and unsubscribed capacity, we will continue to evaluate the application of regulatory accounting principles. Factors which could impact this assessment include an inability to recover cost increases under rate caps and rate case moratoriums, an inability to recover capitalized costs, including an adequate return on those costs through the ratemaking process, excess capacity or significant discounting of rates in the markets we serve, and the impacts of ongoing initiatives in, and deregulation of, the natural gas industry.

While we cannot predict with certainty the final outcome or timing of the resolution of rates and regulatory matters, the outcome of our current re-contracting and capacity subscription efforts, or the outcome of ongoing industry trends and initiatives, 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.

Legal Proceedings

In November 1993, TransAmerican Natural Gas Corporation filed a complaint in a Texas state court against us which sought approximately $7.5 billion in actual and punitive damages related to our 1990 settlement agreement with TransAmerican and others. TransAmerican's complaint advanced ten causes of action. Some of the causes of action were previously dismissed. Trial on the remaining claims began on May 1, 2000. During the trial commencement, all claims against all defendants were settled. The settlement had no material adverse effect on our financial position, results of operations, or cash flows.

In April 1996, a former employee of TransAmerican filed a related case in Harris County, Texas, *Vickroy E. Stone v. Godwin & Carlton, P.C., et al.*, seeking other damages in unspecified amounts related to litigation consulting work allegedly performed for various entities, including EPNG, in cases involving TransAmerican. In June 1998, the court granted our motion for summary judgment and dismissed all claims in the *Stone* litigation. In May 2000, the Texas Court of Appeals in Houston, Texas, upheld the trial court's rulings, except for one claim relating to failure to pay *Stone* a bonus and, in September 2000, the Court of Appeals denied motions for rehearing. EPNG has filed a petition for review with the Texas Supreme Court. Based on information available at this time, we believe that the claims asserted against us in this case have no factual or legal basis.

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 fourteen companies, including some of our current and former affiliates, relating 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.

TGP is a party in proceedings involving federal and state authorities regarding the past use of a lubricant containing polychlorinated biphenyls (PCBs) in its starting air systems. TGP has executed a consent order with the EPA governing the remediation of some 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.

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

A number of our subsidiaries are 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. We have also been named defendants in a similar class action suit, *Quinque Operating Company v. Gas Pipelines*. This 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. We believe both complaints are without merit.

In 1999, our production company was sued in *Clint Miller, et. al. v. Sonat Exploration Company, et. al.,* as a result of the blowout of a well in Bienville, Louisiana which resulted in the deaths of seven individuals and injuries to four others. The plaintiffs sought in excess of $5 billion in compensatory and punitive damages against us and our co-defendents. As of September 30, 2000, we have reached settlements with all the plaintiffs in this case. We are now taking appropriate action and negotiating to recover the settlement amounts from other defendants, non-operating working interest owners, and insurance carriers. At this time, we believe it is probable that we will recover the amounts funded under these settlements.

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 resulting in the deaths of twelve individuals. In September 2000, we were served with a complaint for damages in *Heady, et al. v. EPEC and EPNG*, filed in state district court in Harris County, Texas, brought on behalf of four persons. In October 2000, we were served with a complaint for damages in *Smith v. EPEC and EPNG*, filed in federal district court in Albuquerque, New Mexico, brought on behalf of another person. Both complaints are for damages for personal injuries and wrongful death. Our response in each case is due November 24, 2000. Also, in October 2000, *Smith v. EPNG and EPEC* was filed against us in state district court in Harris County, Texas for damages. To date, the plaintiff has not served us with this complaint. The National Transportation Safety Board is conducting an investigation into the cause of the rupture.

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, claiming EPME improperly cancelled its contracts with PCA during the summer of 1998. The trustee alleges we breached contracts damaging PCA in the amount of $120 million. We have entered into a joint defense agreement with the other defendants. In a related matter, PCA appealed the FERC's 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. Oral arguments in this case are scheduled for January 16, 2001.

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 to have a material adverse effect on our financial position, results of operations, 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 September 30, 2000, we had reserved $235 million for expected environmental costs.

In addition, we expect to make capital expenditures of approximately $3 million in 2000 and a total of $120 million for the years 2001 through 2007 for environmental matters primarily relating to compliance with air regulations and control of water discharges. Some of our subsidiaries have been designated, have received notice that they could be designated, or have been asked for information to determine whether they could be designated as a potentially responsible party with respect to 29 active sites under CERCLA.

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.

8. SEGMENT INFORMATION

We segregate our business activities into five distinct operating segments:

- Natural Gas Transmission;
- Merchant Energy;
- International;
- Field Services; and
- Production.

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 and taxes (EBIT). At the beginning of 2000, we transferred EnCap Investments L.L.C. from the Field Services segment to the Merchant Energy segment. All periods presented have been restated for this change.

	As of and for the Quarter Ended September 30, 2000						
	Natural Gas Transmission	Merchant Energy	International	Field Services	Production	Other[a]	Total
	(In millions)						
Revenues from external customers	$ 331	$ 6,367	$ 20	$ 165	$ 100	$ 4	$ 6,987
Intersegment revenues	40	2	—	24	34	(100)	—
Operating income (loss)	182	53	(4)	22	52	(9)	296
EBIT	207	81	24	30	52	(7)	387
Segment assets	8,661	6,838	1,726	1,683	1,713	1,125	21,746

	As of and for the Quarter Ended September 30, 1999						
	Natural Gas Transmission	Merchant Energy	International	Field Services	Production	Other[a]	Total
	(In millions)						
Revenues from external customers	$ 380	$2,717	$ 14	$ 106	$ 27	$ 18	$ 3,262
Intersegment revenues	15	24	—	18	103	(160)	—
Merger-related costs and asset impairment charges	17	36	—	—	5	—	58
Operating income (loss)	151	(47)	(10)	13	34	3	144
EBIT	166	(33)	12	22	32	7	206
Segment assets	8,811	2,680	1,281	1,463	1,244	901	16,380

[a] Includes corporate, eliminations, and other non-operating segment activities.

	As of and for the Nine Months Ended September 30, 2000						
	Natural Gas Transmission	Merchant Energy	International	Field Services	Production	Other[(a)]	Total
	(In millions)						
Revenues from external customers	$1,071	$12,536	$ 75	$ 425	$ 207	$ 6	$14,320
Intersegment revenues	106	18	—	57	195	(376)	—
Merger-related costs and asset impairment charges	—	—	—	—	—	46	46
Operating income (loss)	575	246	(11)	65	159	(86)	948
EBIT	621	283	69	85	159	(78)	1,139
Segment assets	8,661	6,838	1,726	1,683	1,713	1,125	21,746

	As of and for the Nine Months Ended September 30, 1999						
	Natural Gas Transmission	Merchant Energy	International	Field Services	Production	Other[(a)]	Total
	(In millions)						
Revenues from external customers	$1,179	$6,542	$ 43	$ 281	$ 80	$ 12	$ 8,137
Intersegment revenues	47	32	—	56	260	(395)	—
Merger-related costs and asset impairment charges	17	36	—	—	5	135	193
Ceiling test charges	—	—	—	—	352	—	352
Operating income (loss)	570	(38)	(29)	35	(277)	(153)	108
EBIT	610	(20)	31	73	(278)	(133)	283
Segment assets	8,811	2,680	1,281	1,463	1,244	901	16,380

(a) Includes corporate, eliminations, and other non-operating segment activities.

9. INVESTMENT 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 September 30,		Nine Months Ended September 30,	
	2000	1999	2000	1999
	(In millions)			
Operating results data				
Revenues and other income	$325	$246	$813	$690
Costs and expenses	262	197	688	564
Income from continuing operations	63	49	125	126
Net income	63	33	101	82

East Asia Power

At December 31, 1999, we held a 92 percent ownership interest in East Asia Power Resources Corporation. In March 2000, we converted our investment into a 50/50 joint venture with a third party. In the transaction, we received $85 million, net of transaction costs, and recognized a $20 million benefit. At the time of the conversion, our investment in East Asia Power was $131 million. East Asia Power owns and operates seven power generation facilities in the Philippines and one plant in China, with a total generating capacity of 412 megawatts. Electric power generated by the facilities is supplied to a diversified base of customers, including National Power Corporation, the Philippine state-owned utility, private distribution companies and industrial users.

Chaparral Investors

During the first quarter of 2000, Chaparral completed its acquisitions of several domestic non-utility generation assets including equity interests in eleven natural gas-fired combined generation facilities in California, two natural gas-fired electric generation plants located in Dartmouth, Massachusetts and Pawtucket, Rhode Island, and all the outstanding shares of Bonneville Pacific Corporation, which owns a 50 percent interest in a power generation facility. Chaparral also acquired several operating companies which provide the services required to operate and maintain these newly acquired facilities and a natural gas service company which provides fuel procurement services to eight of Chaparral's natural gas-fired combined generation facilities in California. Chaparral acquired these assets from us in exchange for notes payable in the amount of $385 million. In March 2000, Chaparral's third-party investor increased its overall investment in Chaparral by $1,027 million. The proceeds were used by Chaparral to repay $647 million of notes from us, to make a $278 million contribution to a trust as provided in the Chaparral agreement, to invest in a note with us, and to fund transaction costs. Also, in March 2000, we issued mandatorily convertible preferred stock to a trust we control. Upon the occurrence of certain negative events, the trustee of the trust may be required to remarket this preferred stock on terms that are designed to generate $1 billion to distribute to the third party investor.

Under our management agreement with Chaparral, we earn a performance-based management fee. We are also reimbursed for expenses we incur on behalf of Chaparral. For 2000, our management fee related to Chaparral has been established at $100 million. This fee includes an $80 million performance-based component and a $20 million reimbursement for costs we will incur on behalf of Chaparral. This fee is collected and recognized ratably throughout the year as management services are provided.

El Paso Energy Partners

During the third quarter of 2000, El Paso Energy Partners, the master-limited partnership in which we are the general partner, completed a public offering of 4.6 million common units. The offering reduced our common unit ownership interest from 32.5 percent to 28.4 percent. This transaction had no effect on our general partner interest or our non-managing member interest. Also, in the third quarter, we received $170 million of Series B 10% Cumulative Redeemable Preference Units in exchange for the transfer to the partnership of the natural gas storage businesses of Crystal Gas Storage, Inc., our wholly owned subsidiary.

10. MINORITY INTEREST

In May 2000, we formed Clydesdale Associates, L.P., a limited partnership, and several other separate legal entities to generate funds to invest in capital projects and other assets. We contributed $55 million into this structure and a third-party investor contributed $250 million. The third-party investor is entitled to an adjustable preferred return derived from the net income of the partnership. Clydesdale used the proceeds to invest in a note receivable with us. The third-party's contributions are collateralized by production properties, rental income from real estate assets, and notes receivable from us. We have the option to acquire the third-party's interest in the structure at any time prior to May 2005. If we do not exercise this option, or if the agreement is not extended, the note receivable will mature and a portion of the proceeds will be used to redeem the third-party investor's interest in the structure. The assets, liabilities, and operations of the partnership and the other entities involved in this transaction are included in our consolidated financial statements. The third-party investor's interest is included as minority interest in our balance sheets and their preferred return is included in minority interest in our statements of income.

11. COMPANY-OBLIGATED PREFERRED SECURITIES

In May 2000, we formed El Paso Energy Capital Trust IV which issued $300 million of preferred securities to a third party investor. These preferred securities pay cash distributions at a floating rate equal to the three-month LIBOR plus 75 basis points. As of September 30, 2000, the floating rate was 7.43%. These preferred securities must be redeemed by Trust IV no later than November 30, 2003. Proceeds from the sale of the securities were used by Trust IV to purchase a series of our floating rate senior debentures whose yield and maturity terms mirror those of Trust IV's preferred securities. The sole assets of Trust IV are these floating rate senior debentures. We guarantee the obligations of Trust IV related to its preferred securities. At the time Trust IV issued the preferred securities, we also agreed to issue $300 million of equity securities, including, but not limited to, our common stock in one or more public offerings prior to May 31, 2003.

12. NEW ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

Accounting for Derivative Instruments and Hedging Activities

In June of 1998, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards (SFAS) No. 133, *Accounting for Derivative Instruments and Hedging Activities.* In June of 1999, the FASB extended the adoption date of SFAS No. 133 through the issuance of SFAS No. 137, *Deferral of the Effective Date of SFAS 133.* In June 2000, the FASB issued SFAS No. 138, *Accounting for Certain Derivative Instruments and Certain Hedging Activities,* which also amended SFAS No. 133. SFAS No. 133, and its amendments and interpretations, establishes accounting and reporting standards for derivative instruments, including derivative instruments embedded in other contracts, and derivative instruments used for hedging activities. It will require that we measure all derivative instruments at their fair value, and classify them as either assets or liabilities on our balance sheet, with a corresponding offset to income or other comprehensive income depending on their designation, their intended use, or their ability to qualify as hedges under the standard.

We will adopt SFAS No. 133 beginning January 1, 2001, and will apply the standard to all derivative instruments that exist on that date, except for derivative instruments embedded in other contracts. As provided for in SFAS No. 133, we will apply the provisions of the standard to derivative instruments embedded in other contracts issued, acquired, or substantively modified after December 31, 1998.

We use a variety of derivative instruments to conduct both energy trading activities and to hedge risks associated with commodity prices, foreign currencies and interest rates. The derivative instruments we use in commodity trading activities are currently recorded at their fair value in our financial statements under the provisions of Emerging Issues Task Force Issue No. 98-10, *Accounting for Contracts Involved in Energy Trading and Risk Management Activities.* As a result, SFAS No. 133 will not impact our accounting for these instruments.

Based on commodity prices and quarter ending interest rates existing at September 30, 2000, we estimate that the impact on our financial statements of adopting SFAS No. 133 on January 1, 2001, will be to record a charge to other comprehensive income which could range from $450 to $500 million, and a charge to income which could range from $0 to $30 million. These amounts will be classified as a cumulative effect of a change in accounting principle. The majority of the initial charge to other comprehensive income relates to contracts to sell the natural gas we expect to produce through the end of 2001.

The amounts that will be recorded upon adoption of SFAS No. 133 may materially differ from those disclosed above since the amounts recorded will be based on the fair values that exist at the adoption date. In addition, further interpretation and guidance from the standard setting groups on the proper application of SFAS No. 133's provisions may also substantially alter these estimates.

Revenue Recognition in Financial Statements

In December 1999, the Securities and Exchange Commission issued Staff Accounting Bulletin (SAB) No. 101, *Revenue Recognition in Financial Statements*, to provide guidance for revenue recognition issues and disclosure requirements. SAB No. 101 offers guidelines, examples, and explanations for certain matters relating to the recognition of revenue and will be effective for us in the fourth quarter of 2000. We do not believe the adoption of SAB No. 101 will have a material impact on our financial position, results of operations, or cash flows.

Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities

In September 2000, the FASB issued SFAS No. 140, *Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities,* which replaces SFAS No. 125. This statement revises the standards for accounting for securitizations and other transfers of financial assets and collateral and requires certain disclosures, but carries over most of SFAS No. 125's provisions without reconsideration. This standard has various effective dates, the earliest of which is for fiscal years ending after December 15, 2000. 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 this section updates, and should be read in conjunction with, information disclosed in Part II, Items 7, 7A, and 8, in our Annual Report on Form 10-K for the year ended December 31, 1999, in addition to the financial statements and notes presented in Item 1 of this Quarterly Report on Form 10-Q.

Recent Developments

Merger with The Coastal Corporation

In January 2000, we entered into a definitive agreement to merge with Coastal. In the merger, we will convert each share of Coastal's common stock and Class A common stock into 1.23 shares of our common stock. We will exchange Coastal's outstanding convertible preferred stock for our common stock on the same basis as if we had converted the preferred stock into Coastal's common stock immediately prior to the merger. At September 30, 2000, the total value of the transaction was approximately $23 billion, including $7 billion of assumed debt and preferred equity. We will account for the transaction as a pooling of interests. On May 5, 2000, Coastal's stockholders approved and adopted the merger agreement and our stockholders approved the issuance of the common shares in connection with the merger. On July 26, 2000, the FERC approved the merger. We expect the transaction to close in the fourth quarter of 2000 once we have received all necessary approvals, including the approval by the FTC.

Coastal is a diversified energy holding company. It is engaged, through its subsidiaries and joint ventures, in natural gas transmission, storage, gathering, processing and marketing; natural gas and oil exploration and production; and petroleum refining, marketing and distribution. It owns interests in approximately 18,000 miles of natural gas pipelines extending across the midwestern and the Rocky Mountain areas of the United States and has proved reserves of 3.6 Tcfe.

Purchase of Texas Midstream Operations

In January 2000, we entered into an agreement to purchase the natural gas and natural gas liquids businesses of PG&E Gas Transmission, Texas Corporation, and PG&E Gas Transmission Teco, Inc. The value of the transaction is approximately $840 million, including assumed debt of $561 million. On October 25, 2000, we signed an FTC consent decree to allow us to complete this acquisition. As part of the normal review process, the consent decree must be approved by the FTC. We are also finalizing a similar agreement with the State of Texas. We expect both agreements to become final and the transaction to close in the fourth quarter of 2000. We will account for the transaction as a purchase and will include the acquired assets and operations in our Field Services segment. Some of these acquired operations may be appropriate for acquisition by El Paso Energy Partners, the master-limited partnership of which we are the general partner.

The businesses we are acquiring consist of 8,500 miles of intrastate natural gas transmission pipelines, nine natural gas processing plants that currently process 1.5 Bcf/d, and a 7.2 Bcf natural gas storage field. They also own significant natural gas liquids pipelines and fractionation facilities.

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[1] As generally used in the energy industry and in this document, the following terms have the following meanings:

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

When we refer to natural gas and oil in "equivalents," we are doing so to compare quantities of oil with quantities of natural gas or to express these different commodities in a common unit. In calculating equivalents, we use a generally recognized standard in which one Bbl is equal to approximately six Mcf.

Merger Costs

As we complete our proposed Coastal and Texas Midstream transactions and begin to integrate the activities and operations of these businesses, we will incur transaction, severance, transition, and other merger-related charges that will have a significant impact on our results of operations and financial position. These costs may include, but are not limited to, write-offs or write-downs of duplicate assets, charges to relocate assets and employees, contract termination charges, and charges to align accounting policies and practices. During the third quarter of 2000, we announced a plan to combine our pipeline operations with Coastal's pipeline operations. Under the consolidation plan, EPNG's operations will be relocated from El Paso, Texas to Colorado Springs, Colorado, and ANR Pipeline Company, a subsidiary of Coastal, will be relocated from Detroit, Michigan, to Houston, Texas. In addition to merger-related charges, we will be required to sell assets as a condition of the FTC to completing these transactions.

Under current accounting rules, some of our merger-related costs will be accrued at the merger date, while others will be expensed as incurred. All accrued merger-related costs in a pooling of interests transaction, such as our proposed merger with Coastal, will be recorded in our results of operations. In a purchase transaction, such as our proposed Texas Midstream acquisition, these costs will be included as a component of our purchase price.

In October 2000, we entered into an agreement with a third-party to sell our interest in Oasis Pipeline Company. The sale is contingent upon the approval of the FTC and the Texas Attorney General. We expect to incur a loss on this transaction of approximately $20 million, net of income taxes. However, we do not expect this sale or any other required sales, individually or in total, to have a material adverse effect on our ongoing financial position, results of operations, or cash flows.

Results of Operations

For the quarter ended September 30, 2000, our net income was $137 million versus $39 million for the same period in 1999. EBIT was $387 million for the quarter ended September 30, 2000, versus $206 million for the same period in 1999. Growth in earnings of our non-regulated segments contributed to the increase in consolidated EBIT and amounted to 47 percent of our overall third quarter 2000 EBIT. Partially offsetting this increase were higher interest and debt expense and income taxes in the third quarter of 2000.

For the nine months ended September 30, 2000, our net income was $525 million versus a net loss of $77 million for the same period in 1999. EBIT was $1,139 million for the nine months ended September 30, 2000 versus $283 million for the same period in 1999, with our non-regulated business units comprising approximately 45 percent of our 2000 total. Stronger performance in all of our non-regulated segments and a gain on the sales of our East Tennessee and Sea Robin pipeline systems in compliance with the FTC order related to our 1999 merger with Sonat contributed to the increase. The variance was further impacted by a first quarter 1999 ceiling test write-down in our Production segment under the full cost accounting method and merger costs related to Sonat in the second quarter of 1999. These increases were offset by higher interest and debt expense and income taxes during 2000.

Segment Results

Our September 30, 1999, financial information includes the combined historical results of El Paso Energy and Sonat to reflect our October 1999 merger with Sonat, which was accounted for as a pooling of interests.

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2000	1999	2000	1999
	(In millions)			
Earnings Before Interest Expense and Income Taxes				
Natural Gas Transmission	$207	$166	$ 621	$ 610
Merchant Energy	81	(33)	283	(20)
International	24	12	69	31
Field Services	30	22	85	73
Production	52	32	159	(278)
Segment total	394	199	1,217	416
Corporate, net	(7)	7	(78)	(133)
Consolidated EBIT	$387	$206	$1,139	$ 283

Natural Gas Transmission

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2000	1999	2000	1999
	(In millions, except volume amounts)			
Operating revenues	$ 371	$ 395	$ 1,177	$ 1,226
Operating expenses	(189)	(244)	(602)	(656)
Other income	25	15	46	40
EBIT	$ 207	$ 166	$ 621	$ 610
Throughput volumes (BBtu/d)				
TGP	4,226	4,197	4,651	4,845
EPNG	4,617	3,992	4,185	3,956
SNG	1,848	2,562	2,231	2,698
Equity investments (our share)	827	1,378	1,074	1,120
Total throughput	11,518	12,129	12,141	12,619

Third Quarter 2000 Compared to Third Quarter 1999

Operating revenues for the quarter ended September 30, 2000, were $24 million lower than the same period in 1999. This decrease was due to the impact of our sale of the East Tennessee Pipeline and Sea Robin systems in the first quarter of 2000. Also contributing to the decrease was the impact of customer settlements in 2000 on TGP, lower rates as a result of SNG's May 2000 rate case settlement, and the elimination of the minimum bill provisions on our Elba Island facility that the FERC approved for reactivation. These decreases were partially offset by higher revenues from transportation and other services on each of our transmission systems and revenues from our January 2000 acquisition of Crystal Gas Storage, Inc. In August 2000, we transferred Crystal's gas storage businesses to El Paso Energy Partners in exchange for preference units of the Partnership.

Operating expenses for the quarter ended September 30, 2000, were $55 million lower than the same period in 1999. The decrease was due to cost efficiencies following our merger with Sonat, the sales of our East Tennessee Pipeline and Sea Robin systems, and lower system operating costs. Also contributing to the decrease was the resolution of a contested rate matter with a customer of EPNG, revised estimates of regulatory recoveries on EPNG, and impairment of several SNG expansion projects, all occurring in the third quarter of 1999. The decrease was partially offset by higher utility costs in the third quarter of 2000.

Other income for the quarter ended September 30, 2000, was $10 million higher than the same period in 1999 due to increased equity earnings from Citrus as a result of a one-time gain recorded in 2000 and a gain on the sale of non-pipeline assets during 2000. The increase was partially offset by lower allowance for funds used during construction.

Nine Months Ended 2000 Compared to Nine Months Ended 1999

Operating revenues for the nine months ended September 30, 2000, were $49 million lower than the same period in 1999. This decrease was due to the impact of our sales of the East Tennessee Pipeline and Sea Robin systems in the first quarter of 2000 as well as the favorable resolution of regulatory issues in 1999 on TGP. Also contributing to the decrease were lower rates as a result of SNG's May 2000 rate case settlement, lower revenues from relinquished capacity on EPNG, the impact of customer settlements in 2000 on TGP, and the elimination of the minimum bill provisions on our Elba Island facility. These decreases were partially offset by higher revenues from transportation and other services provided on each of our transmission systems and revenues from our January 2000 acquisition of Crystal Gas Storage, Inc.

Operating expenses for the nine months ended September 30, 2000, were $54 million lower than the same period in 1999. The decrease was due to cost efficiencies following our merger with Sonat, the sales of our East Tennessee Pipeline and Sea Robin systems in March 2000, lower system operating costs, and the favorable impact of FERC's authorization to reactivate SNG's Elba Island facility in the first quarter of 2000. Also contributing to the decrease was the resolution of a contested rate matter with a customer of EPNG, revised estimates of regulatory recoveries on EPNG, and the impairment of several SNG expansion projects, all occurring in the third quarter of 1999. The decrease was partially offset by resolutions of TGP's customer imbalance issues in 1999 as well as the impact of unfavorable producer settlements in the second quarter of 2000 on EPNG. Additionally, higher utility costs in the third quarter of 2000 also offset the decrease.

Other income for the nine months ended September 30, 2000, was $6 million higher than the same period in 1999. The increase was due to higher earnings on Citrus as a result of a one-time gain recorded in 2000 as well as gains on the sale of non-pipeline assets in the third quarter of 2000. The increase was partially offset by the favorable settlement of a regulatory issue in 1999, the elimination of an asset for the future recovery of costs of the Elba Island facility, and a lower allowance for funds used during construction.

Merchant Energy

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2000	**1999**	**2000**	**1999**
	(In millions)			
Gross margin and other revenues	$ 78	$ 18	$315	$ 82
Operating expenses	(25)	(65)	(69)	(120)
Other income	28	14	37	18
EBIT	$ 81	$(33)	$283	$ (20)

Third Quarter 2000 Compared to Third Quarter 1999

Total gross margin and other revenues for the quarter ended September 30, 2000, was $60 million higher than the same period in 1999. Commodity market and trading margins were higher as a result of power price volatility, particularly in the western United States, asset management fees earned from Chaparral, which began operations during the latter part of 1999, income from transactions originated in the third quarter of 2000, and margins on the West Georgia power project, which began operating in June 2000. The West Georgia plant is a seasonal peaking facility. These increases were partially offset by transactions originating in the third quarter of 1999. Other revenues increased in 2000 as a result of higher earnings from EnCap's financial services activities in the quarter.

Operating expenses for the quarter ended September 30, 2000 were $40 million lower than the same period in 1999. The decrease was due to reimbursements in 2000 of general and administrative costs relating to Chaparral as well as impairments of tangible and intangible assets in the third quarter of 1999 related to our merger with Sonat.

Other income for the quarter ended September 30, 2000, was $14 million higher than the same period in 1999 due to an increase in equity earnings from power projects and investments, primarily CE Generation.

Nine Months Ended 2000 Compared to Nine Months Ended 1999

Total gross margin and other revenues for the nine months ended September 30, 2000, was $233 million higher than the same period in 1999. Commodity marketing and trading margins increased due to second and third quarter 2000 price volatility in gas and power markets, asset management fees earned from Chaparral, which began operations during the latter part of 1999, higher income from power transactions originated in 2000, and margins on the West Georgia power project. These increases were partially offset by transactions originating in 1999. Other revenues increased due to the acquisition of EnCap in March 1999.

Our commodity marketing and trading margins during 2000 have been significantly impacted by price volatility in the energy markets and the growth of our trading portfolio in 2000. During periods of high price volatility, market opportunities exist that can enhance trading portfolio values and improve operating results. For the remainder of 2000, we anticipate the commodity prices will continue to be volatile, although not necessarily at the same levels or in the same markets as we experienced in the second and third quarters. Our margins are also impacted by asset management fees and cost reimbursements from Chaparral. These fees should continue through the remainder of 2000. Chaparral asset management fees for 2001 are expected to be higher than 2000, and such fees will be finalized in the fourth quarter.

Operating expenses for the nine months ended September 30, 2000, were $51 million lower than the same period in 1999. The decrease was due to reimbursements in 2000 of general and administrative costs relating to Chaparral and impairments of tangible and intangible assets in the third quarter of 1999 related to our merger with Sonat.

Other income for the nine months ended September 30, 2000, was $19 million higher than the same period in 1999 due to higher earnings from power projects and investments, primarily CE Generation.

International

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2000	1999	2000	1999
	(In millions)			
Operating revenues	$ 20	$ 14	$ 75	$ 43
Operating expenses	(24)	(24)	(86)	(72)
Other income	28	22	80	60
EBIT	$ 24	$ 12	$ 69	$ 31

Third Quarter 2000 Compared to Third Quarter 1999

Operating revenues for the quarter ended September 30, 2000, were $6 million higher than the same period in 1999. The increase was due to higher revenues from the Rio Negro project consolidated in August 1999, offset by slightly lower revenues from the Manaus project in 2000.

Operating expenses for the quarter ended September 30, 2000, were unchanged compared to the same period in 1999. Higher costs from the Rio Negro project and higher project development and general and administrative costs were offset by lower costs from the Manaus project during 2000.

Other income for the quarter ended September 30, 2000, was $6 million higher than the same period in 1999. Higher equity earnings from South American and European investments in 2000, earnings on the Hanwha power generation project in South Korea acquired in the third quarter of 2000, and higher interest income were partially offset by gains recorded on the CAPSA equity swap in the third quarter of 1999.

Nine Months Ended 2000 Compared to Nine Months Ended 1999

Operating revenues for the nine months ended September 30, 2000, were $32 million higher than the same period in 1999. Higher revenues from the Rio Negro and Manaus projects were partially offset by lower revenues from the EMA project.

Operating expenses for the nine months ended September 30, 2000, were $14 million higher than the same period in 1999. Higher project development and general and administrative costs as well as higher operating costs from the Rio Negro project were partially offset by lower operating costs on the Manaus and EMA projects.

Other income for the nine months ended September 30, 2000, was $20 million higher than the same period in 1999. The increase was due to the benefit realized from the formation of our East Asia Power joint venture in March 2000, a settlement received from our Indonesian project in May 2000, and 2000 equity swap gains recognized on our CAPSA project, as well as higher interest income. These increases were partially offset by lower equity earnings from investments in various international projects, primarily our investment in East Asia Power in Asia.

Field Services

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2000	1999	2000	1999
	(In millions, except volume amounts)			
Gathering and treating margin	$ 45	$ 41	$ 134	$ 121
Processing margin	19	11	51	32
Total gross margin	64	52	185	153
Operating expenses	(42)	(39)	(120)	(118)
Other income	8	9	20	38
EBIT	$ 30	$ 22	$ 85	$ 73
Throughput volumes (Bbtu/d)				
Gathering and treating	2,871	3,194	2,952	3,270
Processing	1,125	997	1,079	1,036
Throughput rates ($/MMBtu)				
Gathering and treating	$ 0.17	$ 0.14	$ 0.17	$ 0.14
Processing	$ 0.17	$ 0.13	$ 0.17	$ 0.11

Third Quarter 2000 Compared to Third Quarter 1999

Total gross margin for the quarter ended September 30, 2000, was $12 million higher than the same period in 1999. Gathering and treating margins increased due to higher average gathering rates, which are substantially indexed to natural gas prices, and higher average condensate prices, offset by lower gathering and treating volumes. The increase was also partially offset by the March 2000 sale of El Paso Intrastate-Alabama (EPIA) to El Paso Energy Partners. Processing margins increased due to higher liquids prices in 2000 and the acquisition, in April 2000, of an interest in the Indian Basin processing assets.

Operating expenses for the quarter ended September 30, 2000, were $3 million higher than the same period in 1999. The increase is due to higher depreciation and amortization from assets transferred to Field Services from EPNG following a FERC order, partially offset by lower operating costs following the sale of EPIA to El Paso Energy Partners. The increase was also partially offset by cost recoveries from managed facilities in the third quarter of 2000.

Nine Months Ended 2000 Compared to Nine Months Ended 1999

Total gross margin for the nine months ended September 30, 2000, was $32 million higher than the same period in 1999. Gathering and treating margins increased due to higher average gathering rates, which are substantially indexed to natural gas prices, and higher average condensate prices, offset by lower gathering and treating volumes. The increase was also partially offset by the sale of EPIA to El Paso Energy Partners. Processing margins increased due to higher liquids prices in 2000 and the acquisition, in April 2000, of an interest in the Indian Basin processing assets.

Operating expenses for the nine months ended September 30, 2000, were $2 million higher than the same period in 1999 due to higher depreciation and amortization from assets transferred to Field Services from EPNG following a FERC order. The increase was partially offset by lower costs for labor and benefits and operating leases as well as cost recoveries from managed facilities.

Other income for the nine months ended September 30, 2000, was $18 million lower than the same period in 1999. The decrease was primarily due to net gains in 1999 from the sale of our interest in Viosca Knoll, partially offset by a 2000 gain on the sale of a gathering facility in Colorado.

Production

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2000	**1999**	**2000**	**1999**
	(In millions, except volume amounts)			
Natural gas	$ 108	$ 104	$ 324	$ 275
Oil, condensate, and liquids	21	26	72	61
Other	5	—	6	4
Total operating revenues	134	130	402	340
Operating expenses	(82)	(96)	(243)	(617)
Other expenses	—	(2)	—	(1)
EBIT	$ 52	$ 32	$ 159	$ (278)
Volumes				
Natural gas sales (MMcf)	46,297	47,858	139,972	140,714
Oil, condensate, and liquid sales (MBbls)	1,222	1,500	3,965	4,301
Weighted average realized prices				
Natural gas ($/Mcf)	$ 2.32	$ 2.18	$ 2.31	$ 1.96
Oil, condensate, and liquids ($/Bbl)	$ 17.62	$ 17.62	$ 18.20	$ 14.35

Third Quarter 2000 Compared to Third Quarter 1999

Operating revenues for the quarter ended September 30, 2000, were $4 million higher than the same period in 1999. The increase was due to higher realized prices for natural gas partially offset by lower volumes. Realized prices were affected by hedges in place during the period.

We engage in hedging activities on our oil and natural gas production to obtain more determinable cash flows and to mitigate the risk of downward price movements on sales of these commodities. We do this through oil and natural gas swaps.

Operating expenses for the quarter ended September 30, 2000, were $14 million lower than the same period in 1999. The operating expenses reflected decreased labor costs following our 1999 merger with Sonat as well as asset impairment charges in the third quarter of 1999, offset by higher depletion rates during 2000.

Nine Months Ended 2000 Compared to Nine Months Ended 1999

Operating revenues for the nine months ended September 30, 2000, were $62 million higher than the same period in 1999. The increase was due to higher realized prices for natural gas and oil, condensate and liquids. Realized prices were affected by hedges in place during the period.

Operating expenses for the nine months ended September 30, 2000, were $374 million lower than the same period in 1999. The decrease was due to full cost ceiling test charges incurred in the first quarter of 1999, decreased labor costs following our 1999 merger with Sonat, and asset impairment charges in the third quarter of 1999. The decrease was partially offset by higher depletion rates and severance taxes in 2000.

Corporate, net

Third Quarter 2000 Compared to Third Quarter 1999

Corporate expenses for the quarter ended September 30, 2000, were $14 million higher than the same period in 1999. The increase was primarily due to higher equity based compensation costs and lower interest income in the third quarter of 2000.

Nine Months Ended 2000 Compared to Nine Months Ended 1999

Corporate expenses for the nine months ended September 30, 2000, were $55 million lower than the same period in 1999. The decrease was primarily due to the receipt of interest income on a note from the Chaparral project and higher 1999 costs related to our merger with Sonat, partially offset by 2000 costs incurred related to our pending merger with Coastal.

We expect to incur additional merger-related costs throughout the remainder of 2000 and into 2001 as a result of our pending merger with Coastal.

Interest and Debt Expense

Interest and debt expense for the quarter and nine months ended September 30, 2000, was $21 million and $59 million higher than the same periods in 1999 primarily due to higher average borrowings for ongoing capital projects, investment programs, and operating requirements. We anticipate interest and debt expense will continue to exceed last year's levels throughout the remainder of 2000.

Minority Interest

Minority interest for the quarter and nine months ended September 30, 2000, was $20 million and $61 million higher than the same periods in 1999 due to the formation of Sabine River Investors, L.L.C. in June 1999 and the formation of Clydesdale Associates, L.P. and Capital Trust IV in May 2000.

Income Tax Expense (Benefit)

The effective income tax rates for the quarter and nine months ended September 30, 2000, were 33% and 32%. The effective tax rates were lower than the statutory rate of 35% due to foreign income that is not taxed in the U.S., exclusions of part of the earnings of our unconsolidated equity investees where we anticipate receiving dividends, and the utilization of loss carryforwards. This decrease was offset by foreign income taxed at foreign tax rates higher than U.S. tax rates.

The effective income tax rates for the quarter and nine months ended September 30, 1999, were 39% and 34%. For both periods, the difference from the 35% statutory rate was primarily due to merger-related costs, offset by foreign income that is not taxable in the U.S. and exclusions of part of the earnings from unconsolidated equity investees where we anticipate receiving dividends.

Liquidity and Capital Resources

Cash From Operating Activities

Net cash used in our operating activities was $305 million for the nine months ended September 30, 2000, compared to net cash provided of $375 million for the same period of 1999. The decrease was primarily attributable to increases in our price risk management activities, higher cash payments in 2000 for charges related to the Sonat merger, higher interest payments in 2000, and higher cash payments for legal settlements.

Cash From Investing Activities

Net cash used in our investing activities was $945 million for the nine months ended September 30, 2000. Our investing activities consisted of additions to joint ventures and equity investments, including an increase in our Chaparral equity investment, the purchase of an additional 18.5% interest in CAPSA, and the purchase of an investment in Hanwha Energy Co., Ltd. Other additions included the acquisitions of Crystal Gas Storage, Inc. and Enerplus Global Management, the All American pipeline assets, an interest in the Indian

Basin gas processing plant assets, and expenditures for expansion and construction projects. Investment activities also included proceeds from the sales of our East Tennessee pipeline system, Sea Robin pipeline system, El Paso Intrastate-Alabama pipeline system, our one-third interest in the Destin pipeline system, the proceeds from the formation of our East Asia Power joint venture, and the repayment of a note receivable from Chaparral.

Cash From Financing Activities

Net cash provided by our financing activities was $874 million for the nine months ended September 30, 2000. Cash provided from our financing activities included the issuance of preferred securities of El Paso Energy Capital Trust IV, an interest in Clydesdale Associates, L.P., and notes related to Chaparral. During 2000, we repaid short-term borrowings, paid dividends, and retired long-term debt.

In August 2000, we replaced our $1,250 million 364-day renewable revolving credit and competitive advance facility with a $2 billion facility and our $750 million 3-year revolving credit and competitive advance facility with a $1 billion facility. EPNG and TGP are also designated borrowers under these new facilities. The interest rate for these facilities varies and would have been LIBOR plus 50 basis points on September 30, 2000. The available credit under these facilities is expected to be used for general corporate purposes including, but not limited to, supporting our commercial paper programs.

In October 2000, we issued $300 million ($296 million, net of issuance costs) aggregate principal amount 8.05% medium-term notes due 2030. The proceeds were used to repay $275 million of commercial paper borrowings with the remainder used for other corporate purposes.

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)
October 20, 1999	$0.200	January 11, 2000	$46
January 17, 2000	$0.206	April 3, 2000	$47
April 27, 2000	$0.206	July 3, 2000	$47
July 10, 2000	$0.206	October 2, 2000	$48

In October 2000, we declared a quarterly dividend of $0.206 per share on our common stock, payable on January 2, 2001, to stockholders of record on November 30, 2000. Also during the nine months ended September 30, 2000, we paid dividends of $19 million on the 8¼% cumulative preferred stock, Series A of our subsidiary, El Paso Tennessee Pipeline Co.

We expect that future funding for 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.

Commitments and Contingencies

See Note 7, which is incorporated herein by reference.

Other

As part of our ongoing strategy, we may consider assets we acquire or intend to acquire, as well as assets we own, as potential acquisitions by El Paso Energy Partners. Any of these transactions would be subject to the approval of El Paso Energy Partners' unitholders or board of directors, and, as necessary, appropriate regulatory bodies, as well as subject to a fairness opinion of a third party on the price to be paid by the partnership.

Since the beginning of 2000, we transferred our El Paso Intrastate-Alabama pipeline system and our natural gas storage businesses of Crystal Gas Storage, Inc. to El Paso Energy Partners. The total consideration for these transactions was $197 million.

New Accounting Pronouncements Not Yet Adopted

See Note 12, 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 PG&E's Texas midstream and Coastal's 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 political and economic risks associated with current and future operations in foreign countries; 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 Annual Report on Form 10-K for the year ended December 31, 1999.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

This information updates, and should be read in conjunction with, information disclosed in Part II, Item 7A in our Annual Report on Form 10-K for the year ended December 31, 1999, in addition to the information presented in Items 1 and 2 of this Quarterly Report on Form 10-Q.

Presented below is our estimated potential one-day unfavorable impact on EBIT, as measured by Value at Risk (VAR) calculations, related to contracts held for trading purposes. The average VAR value is calculated from the month end values for the first nine months during 2000. The high and low VAR values represent the highest and lowest month end values during 2000. The VAR calculation is directly impacted by higher volatility in natural gas and power prices. Assuming a confidence level of 95 percent and a one-day holding period, our estimated potential one-day unfavorable impact on EBIT is as follows:

	Quarter Ended September 30, 2000	Nine Months Ended September 30, 2000
	(In millions)	
Highest	$13	$15
Lowest	$ 7	$ 2
Average	$10	$ 7

Our VAR was approximately $3 million at December 31, 1999, and approximately $10 million at September 30, 2000.

In May 2000, we exercised our right to terminate our CAPSA Equity Swap Agreement and to purchase the counterparty's 18.5 percent interest in CAPSA's common stock secured under the swap agreement for approximately $127 million.

During the third quarter of 2000, we entered into additional hedge transactions relating to our Production segment activities and entered into transactions to protect pricing differentials on certain pipeline capacity contracts.

In November, we terminated an interest rate swap with a notional amount of $600 million and a termination date of July 2001. The swap was originally put into place to swap the 6.625% fixed interest rate on our July 1999, $600 million aggregate principal Senior Notes due 2001 with a variable interest rate. The termination of the swap did not have a material impact on our financial results.

We have entered into additional Canadian dollar foreign currency forward purchase and sale contracts subsequent to December 31, 1999. The following table summarizes the notional amounts, average settlement rates, and fair value for Canadian dollar foreign currency forward purchase and sale contracts as of September 30, 2000:

		Notional Amount in Foreign Currency (in millions)	Average Settlement Rates	Fair Value in U.S. Dollars (in millions)
Canadian Dollars	Purchase	(604)	0.675	$(4)
	Sell	465	0.673	5
				$ 1

The following table summarizes Canadian dollar foreign currency forward purchase and sale contracts by expected maturity dates along with annual anticipated cash flow impacts as of September 30, 2000:

		Expected Maturity Dates						
		2000	2001	2002	2003	2004	Thereafter	Total
Canadian Dollars	Purchase	$(9)	$(209)	$(74)	$(70)	$(23)	$(23)	$(408)
	Sell	11	162	58	60	22	—	313
	Net cash flow effect	$ 2	$ (47)	$(16)	$(10)	$ (1)	$(23)	$ (95)

PART II — OTHER INFORMATION

Item 1. Legal Proceedings

See Part I, Financial Information, Note 7, which is incorporated herein by reference.

Item 2. Changes in Securities and Use of Proceeds

None.

Item 3. Defaults Upon Senior Securities

None.

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

None.

Item 5. Other Information

None.

Item. 6. Exhibits and Reports on Form 8-K

a. Exhibits

Each exhibit identified below is filed as a part of this report. Exhibits not incorporated by reference to a prior filing are designated by an asterisk; all exhibits not so designated are incorporated herein by reference to a prior filing as indicated.

Exhibit Number		Description
1.A	—	Restated Distribution Agreement dated October 5, 2000 between the Registrant, Banc of America Securities LLC, ABN AMRO Incorporated and Chase Securities Inc. (Exhibit 1.1 to the El Paso Energy Form 8-K dated October 18, 2000)
1.B	—	Terms Agreement dated October 5, 2000, between the Registrant, Banc of America Securities LLC, ABN AMRO Incorporated and Chase Securities Inc. (Exhibit 1.2 to the El Paso Energy Form 8-K dated October 18, 2000)
1.C	—	Calculation Agent Agreement dated October 5, 2000, between the Registrant and The Chase Manhattan Bank. (Exhibit 1.3 to the El Paso Energy Form 8-K dated October 18, 2000)
4.E	—	Indenture dated as of May 10, 1999, by and between the Registrant and The Chase Manhattan Bank, as Trustee. (Exhibit 4.1 to the El Paso Energy Form 8-K dated May 10, 1999)
4.J	—	Form of 8.050% Medium Term Senior Note. (Exhibit 4.2 to the El Paso Energy Form 8-K dated October 18, 2000)
*10.A	—	$2,000,000,000 364-Day Revolving Credit and Competitive Advance Facility Agreement dated August 4, 2000, by and among El Paso Energy 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, Citibank N.A. and ABN Amro Bank, N.V. as co-documentation agents for the Lenders and Bank of America, N.A. as syndication agent for the Lenders.

Exhibit Number	Description
*10.B	— $1,000,000,000 3-Year Revolving Credit and Competitive Advance Facility Agreement dated August 4, 2000, by and among El Paso Energy 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, Citibank N.A. and ABN Amro Bank, N.V. as co-documentation agents for the Lenders and Bank of America, N.A. as syndication agent for the Lenders.
*27	— Financial Data Schedule

Undertaking

The undersigned hereby undertakes, 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 long-term debt of El Paso Energy and its consolidated subsidiaries not filed herewith for the reason that the total amount of securities authorized under any of such instruments does not exceed 10 percent of the total consolidated assets of El Paso Energy and its consolidated subsidiaries.

b. Reports on Form 8-K

We filed a current report on Form 8-K, dated July 28, 2000, announcing that we received approval from FERC on our anticipated merger with Coastal.

We filed a current report on Form 8-K, dated August 18, 2000, updating pro forma financial statements relating to the proposed merger with The Coastal Corporation.

We filed a current report on Form 8-K, dated October 18, 2000, filing exhibits in connection with an offering of medium term notes pursuant to a Registration Statement on Form S-3.

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 ENERGY CORPORATION

Date: November 8, 2000

/s/ H. BRENT AUSTIN

H. Brent Austin
Executive Vice President and
Chief Financial Officer

Date: November 8, 2000

/s/ JEFFREY I. BEASON

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

INDEX TO EXHIBITS

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