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, 2005

OR

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

For the transition period from to

Commission File Number 1-14365

El Paso Corporation

(Exact Name of Registrant as Specified in its Charter)

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

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

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

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

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

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

Common stock, par value $3 per share. Shares outstanding on November 1, 2005: 659,331,810

EL PASO CORPORATION

TABLE OF CONTENTS

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

/d	= per day	Mcfe	= thousand cubic feet of natural gas equivalents
Bbl	= barrels	MMBtu	= million British thermal units
BBtu	= billion British thermal units	MMcf	= million cubic feet
Bcf	= billion cubic feet	MMcfe	= million cubic feet of natural gas equivalents
Bcfe	= billion cubic feet of natural gas equivalents	MW	= megawatt
MBbls	= thousand barrels	NGL	= natural gas liquids
Mcf	= thousand cubic feet	TBtu	= trillion British thermal units

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

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

PART I — FINANCIAL INFORMATION

Item 1. Financial Statements

EL PASO CORPORATION

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

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2005	2004	2005	2004
Operating revenues	$ 810	$1,429	$ 3,176	$ 4,510
Operating expenses				
Cost of products and services	118	390	277	1,215
Operation and maintenance	490	475	1,370	1,249
Depreciation, depletion and amortization	275	270	849	808
Loss on long-lived assets	3	582	384	837
Taxes, other than income taxes	75	67	211	197
	961	1,784	3,091	4,306
Operating income (loss)	(151)	(355)	85	204
Earnings from unconsolidated affiliates	13	617	184	802
Other income, net	51	15	155	89
Interest and debt expense	(344)	(396)	(1,034)	(1,229)
Distributions on preferred interests of consolidated subsidiaries	—	(6)	(9)	(18)
Loss before income taxes	(431)	(125)	(619)	(152)
Income taxes	(108)	77	(165)	135
Loss from continuing operations	(323)	(202)	(454)	(287)
Discontinued operations, net of income taxes	11	(12)	10	(118)
Net loss	(312)	(214)	(444)	(405)
Preferred stock dividends	(9)	—	(17)	—
Net loss available to common stockholders	$ (321)	$ (214)	$ (461)	$ (405)
Basic and diluted loss per common share				
Loss from continuing operations	$(0.51)	$(0.31)	$ (0.73)	$ (0.45)
Discontinued operations, net of income taxes	0.01	(0.02)	0.01	(0.18)
Net loss per common share	$(0.50)	$(0.33)	$ (0.72)	$ (0.63)
Basic and diluted average common shares outstanding	648	639	643	639
Dividends declared per common share	$ 0.04	$ 0.04	$ 0.12	$ 0.12

See accompanying notes.

EL PASO CORPORATION

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

	September 30, 2005	December 31, 2004
ASSETS		
Current assets		
Cash and cash equivalents	$ 887	$ 2,117
Accounts and notes receivable		
Customers, net of allowance of $64 in 2005 and $199 in 2004	1,227	1,388
Affiliates	58	133
Other	135	188
Assets from price risk management activities	1,107	601
Margin and other deposits held by others	885	79
Deferred income taxes	787	418
Other	533	708
Total current assets	5,619	5,632
Property, plant and equipment, at cost		
Pipelines	19,696	19,418
Natural gas and oil properties, at full cost	16,203	14,968
Power facilities	957	1,550
Gathering and processing systems	53	171
Other	603	882
	37,512	36,989
Less accumulated depreciation, depletion and amortization	18,349	18,177
Total property, plant and equipment, net	19,163	18,812
Other assets		
Investments in unconsolidated affiliates	2,760	2,614
Assets from price risk management activities	1,470	1,584
Goodwill and other intangible assets, net	413	428
Other	2,277	2,313
	6,920	6,939
Total assets	$31,702	$31,383

See accompanying notes.

EL PASO CORPORATION

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

	September 30, 2005	December 31, 2004
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Accounts payable		
Trade	$ 948	$ 1,052
Affiliates	14	21
Other	429	483
Short-term financing obligations, including current maturities	1,267	955
Liabilities from price risk management activities	2,090	852
Margin deposits held by us	245	131
Accrued interest	298	333
Other	829	745
Total current liabilities	6,120	4,572
Long-term financing obligations, less current maturities	16,657	18,241
Other		
Liabilities from price risk management activities	1,745	1,026
Deferred income taxes	1,786	1,312
Other	1,893	2,427
	5,424	4,765
Commitments and contingencies		
Securities of subsidiaries	59	367
Stockholders' equity		
4.99% Convertible perpetual preferred stock, par value $0.01 per share; authorized 50,000,000 shares; issued 750,000 shares in 2005; stated at liquidation value	750	—
Common stock, par value $3 per share; authorized 1,500,000,000 shares; issued 666,891,281 shares in 2005 and 651,064,508 shares in 2004	2,001	1,953
Additional paid-in capital	4,627	4,538
Accumulated deficit	(3,253)	(2,809)
Accumulated other comprehensive income (loss)	(471)	1
Treasury stock (at cost); 7,592,540 shares in 2005 and 7,767,088 shares in 2004	(190)	(225)
Unamortized compensation	(22)	(20)
Total stockholders' equity	3,442	3,438
Total liabilities and stockholders' equity	$31,702	$31,383

See accompanying notes.

EL PASO CORPORATION

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

	Nine Months Ended September 30, 2005	2004
Cash flows from operating activities		
Net loss	$ (444)	$ (405)
Income (loss) from discontinued operations, net of income taxes	10	(118)
Net loss from continuing operations	(454)	(287)
Adjustments to reconcile net loss to net cash from operating activities		
Depreciation, depletion and amortization	849	808
Loss on long-lived assets	384	837
Earnings from unconsolidated affiliates, adjusted for cash distributions	13	(579)
Deferred income taxes	(67)	99
Other non-cash items	58	114
Change in margin and other deposits	(692)	62
Other asset and liability changes	(484)	(446)
Cash (used in) provided by continuing operations	(393)	608
Cash (used in) provided by discontinued operations	(5)	191
Net cash (used in) provided by operating activities	(398)	799
Cash flows from investing activities		
Capital expenditures	(1,266)	(1,272)
Net proceeds from the sale of assets and investments	1,113	1,758
Proceeds from settlement of a foreign currency derivative	131	—
Cash paid for acquisitions, net of cash acquired	(1,023)	(47)
Net change in restricted cash	132	470
Other	76	108
Cash (used in) provided by continuing operations	(837)	1,017
Cash provided by discontinued operations	68	1,140
Net cash (used in) provided by investing activities	(769)	2,157
Cash flows from financing activities		
Payments to retire long-term debt and other financing obligations	(1,621)	(1,705)
Net proceeds from the issuance of long-term debt and other financing obligations	1,225	50
Net proceeds from the issuance of preferred stock	723	—
Redemption of preferred stock of subsidiary	(300)	—
Dividends paid	(85)	(75)
Contributions from discontinued operations	63	966
Issuances of common stock, net	—	73
Other	(5)	(34)
Cash used in continuing operations	—	(725)
Cash used in discontinued operations	(63)	(1,331)
Net cash used in financing activities	(63)	(2,056)
Change in cash and cash equivalents	(1,230)	900
Cash and cash equivalents		
Beginning of period	2,117	1,429
End of period	$ 887	$ 2,329

See accompanying notes.

EL PASO CORPORATION

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

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2005	2004	2005	2004
Net loss	$(312)	$(214)	$(444)	$(405)
Foreign currency translation adjustments (net of income taxes of $11 and $4 in 2005 and less than $1 and $51 in 2004)	(5)	3	2	(17)
Unrealized net gains (losses) from cash flow hedging activity				
Unrealized mark-to-market losses arising during period (net of income taxes of $180 and $269 in 2005 and $33 and $45 in 2004)	(325)	(47)	(497)	(70)
Reclassification adjustments for changes in initial value to the settlement date (net of income taxes of $15 and $3 in 2005 and $3 and $18 in 2004)	42	4	23	43
Other comprehensive loss	(288)	(40)	(472)	(44)
Comprehensive loss	$(600)	$(254)	$(916)	$(449)

See accompanying notes.

EL PASO CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

1. Basis of Presentation and Significant Accounting Policies

Basis of Presentation

We prepared this Quarterly Report on Form 10-Q under the rules and regulations of the United States Securities and Exchange Commission. Because this is an interim period filing presented using a condensed format, it does not include all of the disclosures required by generally accepted accounting principles. You should read this Quarterly Report on Form 10-Q along with our 2004 Annual Report on Form 10-K, as amended, which includes a summary of our significant accounting policies and other disclosures. The financial statements as of September 30, 2005, and for the quarters and nine months ended September 30, 2005 and 2004, are unaudited. We derived the balance sheet as of December 31, 2004, from the audited balance sheet filed in our 2004 Annual Report on Form 10-K, as amended. In our opinion, we have made all adjustments which are of a normal, recurring nature to fairly present our interim period results. Due to the seasonal nature of our businesses, information for interim periods may not be indicative of the results of operations for the entire year. During the second quarter of 2005, our Board of Directors approved the sale of our south Louisiana gathering and processing assets, which were part of our Field Services segment. These assets and the results of their operations for the quarter and nine months ended September 30, 2005, have been reflected as discontinued operations. Prior period amounts have not been adjusted as these operations were not material to prior period results or historical trends. Additionally, our financial statements for prior periods include reclassifications to conform to the current period presentation. These reclassifications had no effect on our previously reported net loss or stockholders' equity.

Significant Accounting Policies

Our significant accounting policies are discussed in our 2004 Annual Report on Form 10-K, as amended. The information below provides updating information, disclosure where these policies have changed or required interim disclosures with respect to those policies.

Variable Interest Entities

In 2003, the Financial Accounting Standards Board (FASB) issued Financial Interpretation (FIN) No. 46, *Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51*, which we adopted on January 1, 2004. This interpretation defined a variable interest entity as a legal entity whose equity owners do not have sufficient equity at risk or a controlling financial interest in the entity. This standard requires a company to consolidate a variable interest entity if it is allocated a majority of the entity's losses or income, including fees paid by the entity.

In conjunction with our application of FIN No. 46, we attempted to obtain financial information on several potential variable interest entities but were unable to obtain that information. The most significant of these entities is the Cordova power project which is the counterparty to our largest tolling arrangement. Under this tolling arrangement, we supply on average a total of 54,000 MMBtu of natural gas per day to the entity's two 274 gross MW power facilities and are obligated to market the power generated by those facilities through 2019. In addition, we pay that entity a capacity charge that ranges from $27 million to $32 million annually related to its power plants. The following is a summary of the financial statement impacts of our transactions with this entity for the quarter and nine months ended September 30, 2005 and 2004 and as of September 30, 2005 and December 31, 2004:

	2005	2004
	(In millions)	
Operating revenues for the quarters ended September 30	$ 45	$(27)
Operating revenues for the nine months ended September 30	(66)	(30
Current liabilities from price risk management activities	18	20
Non-current liabilities from price risk management activities	83	29

As of December 31, 2004, our financial statements included two consolidated entities that own a 238 MW power facility and a 158 MW power facility in Manaus, Brazil. In January 2005, these entities entered into agreements with Manaus Energia, under which Manaus Energia will supply substantially all of the fuel consumed and will purchase all of the power generated by the projects through January 2008, at which time Manaus Energia will assume ownership of the plants. We deconsolidated these two entities in January 2005 because Manaus Energia will absorb a majority of the potential losses of the entities under the new agreements and will assume ownership of the plants at the end of the agreements. The impact of this deconsolidation was an increase in investments in unconsolidated affiliates of $103 million, a decrease in property, plant and equipment of $74 million, a decrease in other assets of $32 million and a decrease in other liabilities of $3 million.

Stock-Based Compensation

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

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2005	2004	2005	2004
	(In millions, except per share amounts)			
Net loss available to common stockholders as reported	$ (321)	$ (214)	$ (461)	$ (405)
Add: Stock-based compensation expense in net loss, net of taxes	3	4	8	11
Deduct: Stock-based compensation expense determined under fair value-based method for all awards, net of taxes	5	9	15	28
Net loss available to common stockholders, pro forma	$ (323)	$ (219)	$ (468)	$ (422)
Loss per share:				
Basic and diluted, as reported	$(0.50)	$(0.33)	$(0.72)	$(0.63)
Basic and diluted, pro forma	$(0.50)	$(0.34)	$(0.73)	$(0.66)

New Accounting Pronouncements Issued But Not Yet Adopted

As of September 30, 2005, there were several accounting standards and interpretations that had not yet been adopted by us. Below is a discussion of significant standards that may impact us.

Accounting for Stock-Based Compensation. In December 2004, the FASB issued SFAS No. 123R, *Share-Based Payment: an amendment of SFAS No. 123 and 95*. This standard requires that companies measure and record the fair value of their stock based compensation awards at fair value on the date they are granted to employees. This fair value is determined using a variety of assumptions, including those related to volatility rates, forfeiture rates and the option pricing model used (e.g. binomial or Black Scholes). These assumptions could differ from those we have utilized in determining our pro forma compensation expense (indicated above). This standard will also impact the manner in which we recognize the income tax impacts of our stock compensation programs in our financial statements. This standard is required to be adopted beginning January 1, 2006. Upon adoption, we will apply the standard prospectively for new stock-based compensation arrangements and for the unvested portion of existing arrangements. We are currently evaluating the impact of adoption on our consolidated financial statements.

Accounting for Deferred Taxes on Foreign Earnings. In December 2004, the FASB issued FASB Staff Position (FSP) No. 109-2, *Accounting and Disclosure Guidance for the Foreign Earnings Repatriation Provision within the American Jobs Creation Act of 2004.* FSP No. 109-2 clarified the existing accounting literature that requires companies to record deferred taxes on foreign earnings, unless they intend to indefinitely reinvest those earnings outside the U.S. This pronouncement will temporarily allow companies that are evaluating whether to repatriate foreign earnings under the American Jobs Creation Act of 2004 to delay recognizing any related taxes until that decision is made. This pronouncement also requires companies that are considering repatriating earnings to disclose the status of their evaluation and the potential amounts being considered for repatriation. We have determined that we will not repatriate any foreign earnings under the American Jobs Creation Act and, as a result, this pronouncement will not have an impact on our financial statements.

Accounting for Asset Retirement Obligations. In March 2005, the FASB issued FIN No. 47, *Accounting for Conditional Asset Retirement Obligations.* FIN No. 47 requires companies to record a liability for those asset retirement obligations in which the timing and/or amount of settlement of the obligation are uncertain. These conditional obligations were not addressed by SFAS No. 143, *Accounting for Asset Retirement Obligations*, which we adopted on January 1, 2003. FIN No. 47 will require us to accrue a liability when a range of scenarios indicates that the potential timing and/or settlement amounts of our conditional asset retirement obligations can be determined. We will adopt the provisions of this standard in the fourth quarter of 2005, and anticipate that we will record an asset retirement obligation and related pre-tax charge of up to $30 million to reflect the cumulative effect of accounting change associated with the adoption of this standard.

Accounting for Pipeline Integrity Costs. In June 2005, the Federal Energy Regulatory Commission (FERC), issued an accounting release that will impact certain costs our interstate pipelines incur related to their pipeline integrity programs. This release will require us to expense certain pipeline integrity costs incurred after January 1, 2006, instead of capitalizing them as part of our property, plant and equipment. One of our regulated pipeline subsidiaries, El Paso Natural Gas Company (EPNG), filed a request with the FERC to allow EPNG to adopt the provisions of this release in December 2005. Although we continue to evaluate the impact that this accounting release will have on our consolidated financial statements, we currently estimate that we will be required to expense an additional amount of pipeline integrity costs under this accounting release in the range of approximately $23 million to $39 million annually.

2. Acquisitions

In August 2005, our subsidiary, El Paso Production Holding Company (EPPH), acquired Medicine Bow Energy Corporation, a privately held energy company with an estimated 383 Bcfe of proved reserves, for total cash consideration of $851 million. Of this amount, $814 million was paid for the interests acquired, $23 million was used to repay Medicine Bow indebtedness and $14 million was used for various advisor fees and other costs. Of the proved reserves, our net interest of approximately 253 Bcfe will not be consolidated in our reserves, as these reserves are owned by Four Star Oil and Gas Company, an unconsolidated affiliate of Medicine Bow. Our proportionate share of the future operating results associated with these unconsolidated reserves will be reflected as earnings from unconsolidated affiliates in our financial statements.

We have reflected Medicine Bow's results of operations in our income statement beginning September 1, 2005.

The following summary presents unaudited pro forma consolidated results of operations for the quarters and nine months ended September 30, 2005 and 2004 as if the acquisition had occurred as of the beginning of the periods presented and are not necessarily indicative of the operating results that would have occurred had the acquisition been consummated at that date, nor are they necessarily indicative of future operating results.

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2005[(1)]	2004	2005[(1)]	2004
	(In millions, except per share amounts)			
Revenues	$ 821	$1,436	$ 3,215	$4,546
Net loss	(312)	(217)	(434)	(417)
Basic and diluted loss per share	(0.50)	(0.34)	(0.70)	(0.65)

(1) Excludes a $13 million charge of Medicine Bow for change in control payments triggered as a result of the acquisition.

3. Divestitures

Sales of Assets and Investments

During the nine months ended September 30, 2005 and 2004, we completed the sale of a number of assets and investments in each of our business segments. The following table summarizes the proceeds from these sales:

	2005	2004
	(In millions)	
Regulated		
Pipelines	$ 49	$ 54
Non-regulated		
Production	—	24
Power	468	699
Field Services	501	1,029
Other		
Corporate	121	16
Total continuing	1,139[(1)]	1,822[(1)]
Discontinued	87	1,293
Total	$1,226	$3,115

(1) Proceeds exclude returns of invested capital and cash transferred with the assets sold and include costs incurred in preparing assets for disposal. These items decreased our sales proceeds by $26 million and $64 million for the nine months ended September 30, 2005 and 2004. Proceeds also exclude any non-cash consideration received in these sales.

The following table summarizes the significant assets sold during the nine months ended September 30:

	2005	2004
Pipelines	• Facilities located in the southeastern U.S. • Interest in a gathering system in the western U.S.	• Australia pipeline • Aircraft • Interest in several gathering systems
Production	• None	• Brazilian exploration and production assets
Power	• Cedar Brakes I and II • Interest in a power facility in Korea • Interest in a power plant in India • Interest in a power plant in England • 4 domestic power facilities • Power turbines	• Mohawk River Funding IV • Utility Contract Funding (UCF) • Bastrop Company equity investment • 21 domestic power plants • 5 other domestic power plants and turbines
Field Services	• 9.9% interest in general partner of Enterprise Products Partners, L.P. • 13.5 million common units in Enterprise • Interest in Indian Springs natural gas gathering system and processing facility	• General partnership interest, common units and Series C units of GulfTerra • South Texas processing plants • Dauphin Island and Mobile Bay equity investments
Corporate	• Lakeside Technology Center	• Aircraft
Discontinued	• Interest in Paraxylene facility • MTBE processing facility • International natural gas and oil production properties	• Natural gas and oil production properties in Canada and other international production assets • Aruba and Eagle Point refineries and other petroleum assets

In the fourth quarter of 2005, we completed the sales of our south Louisiana gathering and processing assets in our discontinued operations, our interest in the Javelina natural gas processing and pipeline assets in our Field Services segment and our interest in Mohawk River Funding II, a wholly-owned subsidiary in our Power segment that held a restructured power contract. We received approximately $664 million in proceeds and will record a net gain of approximately $495 million in the fourth quarter of 2005 related to these sales. In addition, during 2005, we have announced the sales of our interest in a power facility in Hungary and substantially all of our other Asian power assets. We expect to receive total proceeds of approximately $284 million for these assets.

Under SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, we classify assets to be disposed of as held for sale or, if appropriate, discontinued operations when they have received appropriate approvals by our management or Board of Directors and when they meet other criteria. As of September 30, 2005 and December 31, 2004, we had assets held for sale of $5 million and $75 million.

Discontinued Operations

South Louisiana Gathering and Processing Operations. During the second quarter of 2005, our Board of Directors approved the sale of our south Louisiana gathering and processing assets, which were part of our Field Services segment. In the fourth quarter of 2005, we completed the sale of these assets for net proceeds of approximately $486 million, and will record a pre-tax gain of approximately $400 million.

International Natural Gas and Oil Production Operations. During 2004, our Canadian and certain other international natural gas and oil production operations were approved for sale. As of December 31, 2004, we had completed the sale of all of our Canadian operations and substantially all of our operations in Indonesia for total proceeds of approximately $389 million. We completed the sale of substantially all of our remaining properties in 2005 for total proceeds of approximately $6 million.

Petroleum Markets. During 2003, our Board of Directors approved the sales of our petroleum markets businesses and operations. These businesses and operations consisted of our Eagle Point and Aruba refineries, our asphalt business, our Florida terminal, tug and barge business, our lease crude operations, our Unilube blending operations, our domestic and international terminalling facilities and our petrochemical and chemical plants. In 2004, we completed the sales of our Aruba and Eagle Point refineries for $880 million.

The petroleum markets, other international natural gas and oil production operations, and south Louisiana gathering and processing operations discussed above are reflected as discontinued operations in our financial statements. As of September 30, 2005 and December 31, 2004, the total assets of our discontinued operations were $197 million and $106 million, and our total liabilities were $118 million and $12 million. These amounts are classified in other current assets and liabilities. The assets and liabilities of our south Louisiana gathering and processing operations as of December 31, 2004, and the results of its operations for periods prior to January 1, 2005, were not reclassified to discontinued operations, as these operations were not material to prior period results or historical trends. The summarized operating results of our discontinued operations were as follows:

	Petroleum Markets	International Natural Gas and Oil Production Operations	South Louisiana Gathering and Processing Operations	Total
		(In millions)		
Quarter Ended September 30, 2005				
Revenues	$ 26	$ —	$ 99	$ 125
Costs and expenses	(30)	—	(89)	(119)
Gain on long-lived assets	1	—	—	1
Other income	1	—	—	1
Income (loss) before income taxes	(2)	—	10	8
Income taxes	(7)	—	4	(3)
Income from discontinued operations, net of income taxes	$ 5	$ —	$ 6	$ 11
Quarter Ended September 30, 2004				
Revenues	$ 44	$ 1	$ —	$ 45
Costs and expenses	(52)	(5)	—	(57)
Gain (loss) on long-lived assets	1	(5)	—	(4)
Other income	14	—	—	14
Income (loss) before income taxes	7	(9)	—	(2)
Income taxes	10	—	—	10
Loss from discontinued operations, net of income taxes	$ (3)	$ (9)	$ —	$ (12)

	Petroleum Markets	International Natural Gas and Oil Production Operations	South Louisiana Gathering and Processing Operations	Total
		(In millions)		
Nine Months Ended September 30, 2005				
Revenues	$ 100	$ 2	$ 276	$ 378
Costs and expenses	(116)	(2)	(246)	(364)
Gain (loss) on long-lived assets	4	(5)	—	(1)
Other income	12	—	—	12
Income (loss) before income taxes	—	(5)	30	25
Income taxes	6	(3)	12	15
Income (loss) from discontinued operations, net of income taxes	$ (6)	$ (2)	$ 18	$ 10
Nine Months Ended September 30, 2004				
Revenues	$ 737	$ 29	$ —	$ 766
Costs and expenses	(782)	(52)	—	(834)
Loss on long-lived assets	(37)	(21)	—	(58)
Other income	6	—	—	6
Interest and debt expense	(3)	1	—	(2)
Loss before income taxes	(79)	(43)	—	(122)
Income taxes	1	(5)	—	(4)
Loss from discontinued operations, net of income taxes	$ (80)	$(38)	$ —	$(118)

4. Restructuring Costs

During 2004 and 2005, we incurred organizational restructuring costs included in our operation and maintenance expenses as part of our liquidity enhancement and cost reduction efforts. The discussion below provides additional details of these costs.

Office relocation and consolidation. As of December 31, 2004, we had a liability related to the consolidation of our Houston based operations. This discounted liability, net of existing sublease rentals, was $110 million as of September 30, 2005. We recorded charges of $27 million during the second quarter of 2005 related to vacating this remaining leased space and signing a termination agreement on the lease. During the nine months ended September 30, 2004, we incurred approximately $30 million of costs related to the consolidation of these Houston based operations.

Employee severance, retention and transition costs. During the nine months ended September 30, 2004, we incurred $35 million of employee severance costs, which included severance payments and costs for pension benefits settled under existing benefit plans. During the nine months ended September 30, 2005, severance costs were not significant. Substantially all of our employee severance costs have been paid as of September 30, 2005.

5. (Gain) Loss on Long-Lived Assets

Our (gain) loss on long-lived assets consists of realized gains and losses on sales of long-lived assets and impairments of long-lived assets, including goodwill and other intangibles. During each of the periods ended September 30, our (gain) loss on long-lived assets was as follows:

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2005	2004	2005	2004
	(In millions)			
Net realized (gain) loss	$ —	$ 6	$(13)	$ (8)
Asset impairments				
Power				
Brazilian assets[1]	—	32	276	183
Central American assets[2]	—	—	60	—
Asian assets[2]	—	—	37	—
Domestic assets and restructured power contract entities[2]	—	51	—	159
Turbines[2]	—	—	15	—
Field Services				
Goodwill impairment[3]	—	480	—	480
Indian Springs processing assets[2]	—	13	—	13
Other	3	—	9	10
Total asset impairments	3	576	397	845
Loss on long-lived assets	3	582	384	837
(Gain) loss on sale of investments in unconsolidated affiliates, net of impairments[4]	39	(506)	7	(464)
Loss on long-lived assets and investments	$ 42	$ 76	$391	$ 373

(1) These assets were impaired as a result of ongoing negotiations associated with the power contracts of these plants. See Note 10 for a further discussion of these matters.
(2) We adjusted the carrying value of these assets to their expected sales price.
(3) This impairment resulted from the sale of substantially all of our interests in GulfTerra, as well as the sale of our processing assets in south Texas to affiliates of Enterprise in 2004 (see Note 14).
(4) See Note 14 for a further description of these gains, losses and impairments.

6. Income Taxes

Income taxes included in our loss from continuing operations for the periods ended September 30 were as follows:

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2005	2004	2005	2004
	(In millions, except rates)			
Income taxes	$(108)	$ 77	$(165)	$135
Effective tax rate	25%	(62)%	27%	(89)%

We compute our quarterly taxes under the effective tax rate method based on applying an anticipated annual effective rate to our year-to-date income or loss, except for significant unusual or extraordinary transactions. Income taxes for significant unusual or extraordinary transactions are computed and recorded in the period that the specific transaction occurs. During 2005, our overall effective tax rate on continuing operations was different than the statutory rate of 35 percent due primarily to:

- Impairments of certain foreign investments for which there was only a partial corresponding income tax benefit, as well as foreign income taxed at different rates;

- Benefits recorded on book versus tax differences related to certain of our Asian and Indian power assets as further described below;

- A reduction of our liabilities for tax contingencies as a result of an IRS settlement on the 1995 to 1997 Coastal Corporation income tax returns, expiration of a tax indemnity claim, and approval and receipt of a 1986 refund claim; and

- Other items including (i) state income taxes (including valuation allowances) and adjustments to reflect income tax returns as filed; (ii) earnings/losses from unconsolidated affiliates where we anticipate receiving dividends; and (iii) non-deductible dividends on the preferred stock of subsidiaries.

We have not historically recorded U.S. deferred tax assets or liabilities on book versus tax basis differences for a substantial portion of our international investments based on our intent to indefinitely reinvest earnings from these investments outside the U.S. However, based on current sales negotiations on certain of our Asian power assets, we currently expect to receive these sales proceeds within the U.S. During the nine months ended September 30, 2005, our effective tax rate was impacted upon recording net U.S. deferred tax assets on book versus tax basis differences in these investments based on the status of these negotiations. We also recorded U.S. deferred tax benefits on the sale of an Indian power asset. As of September 30, 2005, and December 31, 2004, we have U.S. deferred tax assets of $104 million and $6 million and U.S. deferred tax liabilities of $8 million and $39 million related to these investments.

In 2004, our overall effective tax rate on continuing operations was significantly different than the statutory rate due primarily to the GulfTerra transaction and impairments of certain of our foreign investments. The sale of our interests in GulfTerra associated with the merger between GulfTerra and Enterprise in September 2004 resulted in a significant taxable gain (compared to a lower book gain) and significant tax expense due to the non-deductibility of a significant portion of the goodwill written off as a result of the transaction. The impact of this non-deductible goodwill increased our tax expense by approximately $139 million. See Note 14 for a further discussion of the merger and related transactions. Additionally, on the impairment of certain of our foreign investments, primarily during the first quarter of 2004, we received no U.S. federal income tax benefit. The combination of these items resulted in an overall tax expense for a period in which there was a pre-tax loss.

7. Earnings Per Share

We incurred losses from continuing operations during the quarters and nine months ended September 30, 2005 and 2004. Accordingly, we excluded a number of securities from the determination of diluted earnings per share when their impact on income (loss) per common share is antidilutive. These primarily include our convertible preferred stock, which has conversion features that are discussed in Note 12. For a discussion of our other securities that could impact our determination of diluted earnings per share, see our 2004 Annual Report on Form 10-K, as amended.

8. Price Risk Management Activities

The following table summarizes the carrying value of the derivatives used in our price risk management activities as of September 30, 2005 and December 31, 2004. In the table, derivatives designated as hedges primarily consist of instruments used to hedge our natural gas and oil production. Derivatives from power contract restructuring activities relate to power purchase and sale agreements that arose from our activities in that business and other commodity-based derivative contracts relate to our historical energy trading activities.

Interest rate and foreign currency hedging derivatives consist of instruments to hedge our interest rate and currency risks on long-term debt.

	September 30, 2005	December 31, 2004
	(In millions)	
Net assets (liabilities)		
Derivatives designated as hedges[1][2]	$(1,046)	$(536)
Derivatives from power contract restructuring activities	56	665
Other commodity-based derivative contracts[2]	(281)	(61)
Total commodity-based derivatives	(1,271)	68
Interest rate and foreign currency hedging derivatives[3]	13	239
Net assets (liabilities) from price risk management activities[4]	$(1,258)	$ 307

(1) The increase in the liability during the nine months ended September 30, 2005 is due primarily to changes in natural gas prices.

(2) We have a derivative that hedges a portion of the production owned by UnoPaso, a wholly-owned subsidiary that owns natural gas and oil properties in Brazil. As a result of the earlier than expected payout of certain of UnoPaso's natural gas and oil properties, which will reduce our interest in the properties and related production volumes, we recorded an $11 million loss in the third quarter of 2005 related to the elimination of the accumulated other comprehensive loss associated with this hedge and reclassified the hedge as an other commodity based derivative contract.

(3) In March 2005, we repurchased approximately €528 million of debt, of which €375 million was hedged with interest rate and foreign currency derivatives. As a result of the repurchase, we removed the hedging designation on these derivatives and cancelled substantially all of the contracts. We recorded a gain of approximately $2 million during the first quarter of 2005 upon the reversal of the related accumulated other comprehensive income associated with these derivatives.

(4) Included in both current and non-current assets and liabilities on the balance sheet.

Our derivative contracts are recorded in our financial statements at fair value. The best indication of fair value is quoted market prices. However, when quoted market prices are not available, we estimate the fair value of those derivative contracts. Prior to April 2005, we used commodity prices from market-based sources such as the New York Mercantile Exchange for forward pricing data within two years. For forecasted settlement prices beyond two years, we used a combination of commodity pricing data from market-based sources and other independent pricing sources to develop price curves. These curves were then used to estimate the value of settlements in future periods based on the contractual settlement quantities and dates. Finally, we discounted these estimated settlement values using a LIBOR curve for the majority of our derivative contracts or by using an adjusted risk free rate for our restructured power contracts.

Effective April 1, 2005, we began using new forward pricing data provided by Platts Research and Consulting, our independent pricing source, due to their decision to discontinue the publication of the pricing data we had been utilizing in prior periods. In addition, due to the nature of the new forward pricing data, we extended the use of that data over the entire contractual term of our derivative contracts. Prior to April 1, 2005, we only used Platts' pricing data to value our derivative contracts beyond two years. Based on our analysis, the overall impact of this change in estimate was not material to our financial statements.

Derivatives from power contract restructuring activities as of September 30, 2005 includes $56 million of derivative contracts sold in connection with the sale of Mohawk River Funding II in October 2005. In connection with this sale, we also assigned to third parties other commodity-based derivatives that had a fair value of $9 million as of September 30, 2005. Derivatives from power contract restructuring activities as of December 31, 2004 include $596 million of derivative contracts sold in connection with the sale of Cedar Brakes I and II in March 2005. In connection with this sale, we also assigned or terminated other commodity-based derivatives that had a fair value liability of $240 million as of December 31, 2004.

9. Debt, Other Financing Obligations and Other Credit Facilities

We had the following long-term and short-term borrowings and other financing obligations:

	September 30, 2005	December 31, 2004
	(In millions)	
Short-term financing obligations, including current maturities	$ 1,267	$ 955
Long-term financing obligations	16,657	18,241
Total	$17,924	$19,196

We have several debt obligations that are redeemable by holders prior to their maturity date. Included in our short term obligations as of September 30, 2005, are $605 million of zero coupon debentures that the holders may require us to redeem in February 2006. Additionally, we have debt of approximately $600 million that is redeemable by holders in 2007. A number of our debt obligations are also callable by us prior to their stated maturity date. At this time, we have $10.9 billion of debt obligations callable in 2005, an additional $1.4 billion callable in 2006 and an additional $0.6 billion callable in 2007 and thereafter. To the extent we decide to redeem any of this debt, certain obligations will require us to pay a make whole premium.

Long-Term Financing Obligations

From January 1, 2005 through the date of this filing, we had the following changes in our long-term financing obligations:

Company	Type	Interest Rate	Book Value	Cash Received/Paid
			(In millions)	
Issuances				
Colorado Interstate Gas Company (CIG)	Senior notes due 2015	5.95%	$ 200	$ 197
Cheyenne Plains Gas Pipeline Company[1]	Non-recourse term loan due 2015	Variable	266	261
El Paso Production Holding Company	Revolving credit facility due 2010	LIBOR +1.875%	500	495
El Paso[2]	Senior notes due 2007	7.625%	272	272
	Increases through September 30, 2005		$1,238	$1,225
CIG	Senior notes due 2015	6.8%	400	395
	Increases through filing date		$1,638	$1,620
Repayments, repurchases, retirements and other				
El Paso	Zero coupon debenture[3]	—	$ 236	$ 237
El Paso	Notes	6.88%	167	167
Cedar Brakes I[4]	Non-recourse notes	8.5%	241	15
Cedar Brakes II[4]	Non-recourse notes	9.88%	334	14
El Paso[5]	Euro notes	5.75%	695	722
El Paso	Senior notes due 2007	6.14%	272	—[2]
CIG	Debentures	10.00%	180	180
Other	Long-term debt	Various	385	286
	Decreases through September 30, 2005		$2,510	$1,621
Other	Long-term debt	Various	56	27
	Decreases through filing date		$2,566	$1,648

(1) In addition to the borrowing, we have an associated letter of credit facility for $12 million, under which we issued $6 million of letters of credit in May 2005. We also concurrently entered into swaps to convert the variable interest rate on approximately $213 million of this debt to a current fixed rate of 5.94%.

(2) In July 2005, we remarketed $272 million of notes which originally formed a portion of our 9.0% equity security units. Existing note holders utilized proceeds from the remarketing to satisfy their obligation under the equity security units to purchase common stock which had the effect of exchanging debt for equity. We have reflected this transaction as a non-cash financing transaction and the issuance of the new remarketed notes as a financing cash inflow.

(3) This security has a yield-to-maturity of approximately 4%.

(4) Prior to the sale of Cedar Brakes I and II, we made $29 million of scheduled principal repayments. Upon the sale of these entities in March 2005, the remaining balance of the debt was eliminated.

(5) We recorded a $26 million loss on the early extinguishment of this debt.

We recorded accretion expense on our zero coupon bonds of $6 million and $9 million during the third quarters of 2005 and 2004, and $19 million and $27 million during the nine months ended September 30, 2005 and 2004. These amounts are added to the principal balance each period and are included in our long term debt. We account for redemption of zero coupon debentures as a financing activity in our statement of cash flows, which included this accretion. During the nine months ended September 30, 2005 we redeemed $236 million of our zero coupon debentures of which $34 million represented increased principal due to the accretion of interest on the debentures.

Credit Facilities

As of September 30, 2005, we had borrowing capacity under our $3 billion credit agreement of $0.2 billion. Amounts outstanding under the credit agreement were a $1.2 billion term loan and $1.6 billion of letters of credit. For a further discussion of our $3 billion credit agreement, our other credit facilities and our restrictive financial and non-financial covenants and restrictions, see our 2004 Annual Report on Form 10-K, as amended.

In August 2005, our subsidiary EPPH entered into a $500 million five-year senior revolving credit facility bearing interest at LIBOR plus 1.875%. Under the facility, we borrowed $500 million which was used to partially fund the acquisition of Medicine Bow. The facility can be utilized for funded borrowings or for the issuance of letters of credit and is collateralized by certain EPPH natural gas and oil production properties. The availability of borrowings under this facility is subject to various conditions. The financial coverage ratio under the facility requires that EPPH's EBITDA to interest expense not be less than 2.00 to 1.00, EPPH's debt to EBITDA must not be greater than 4.50 to 1.00 until September 30, 2006 and 4.00 to 1.00 thereafter, and EPPH's Collateral Coverage Ratio (as defined in the facility) must be greater than 1.5 to 1.0.

In November 2005, we entered into a $400 million revolving borrowing base credit agreement collateralized by production properties owned by one of our subsidiaries, which is also a co-borrower. Under the agreement we have initial borrowing availability of $300 million. The credit facility can be used for revolving credit loans or for the issuance of letters of credit and will mature in May 2006. The availability of borrowings under this facility is subject to various conditions. One of the more restrictive new covenants of this facility is the requirement to maintain a Collateral Coverage Ratio (as defined in the facility) of at least 1.5 to 1.0.

Letters of Credit

As of September 30, 2005, we had outstanding letters of credit of approximately $1.6 billion of which approximately $1.2 billion collateralize our recorded obligations related to price risk management activities.

10. Commitments and Contingencies

Legal Proceedings

Western Energy Settlement. In June 2003, we entered into various agreements to resolve the principal litigation, investigations, claims, and regulatory proceedings arising out of the sale or delivery of natural gas and/or electricity to the western United States (the Western Energy Settlement). In April 2005, we paid the remaining $442 million due under a 20 year cash payment obligation that arose under certain of these agreements and recorded an additional $59 million charge in the first quarter of 2005 resulting from this prepayment. These agreements also included a Joint Settlement Agreement (JSA) where we agreed to certain conditions regarding service and facilities on EPNG. In June 2003, El Paso, the California Public Utilities Commission (CPUC), Pacific Gas and Electric Company, Southern California Edison Company, and the City of Los Angeles filed the JSA with the FERC. In November 2003, the FERC approved the JSA with minor modifications. Our east of California shippers filed requests for rehearing, which were denied by the FERC on March 30, 2004. Certain shippers appealed the FERC's ruling to the U.S. Court of Appeals for the District of Columbia. The court dismissed the appeal, but held that shippers can advance similar arguments in EPNG's rate case for the FERC's consideration and action.

Shareholder/Derivative/ERISA Litigation

Shareholder Litigation. Twenty-eight purported shareholder class action lawsuits have been pending since 2002 and are consolidated in federal court in Houston, Texas. This consolidated lawsuit, which alleges violations of federal securities laws against us and several of our current and former officers and directors, includes allegations regarding the accuracy or completeness of press releases and other public statements made during the class period from 2000 through early 2004 related to wash trades, mark-to-market accounting, off-balance sheet debt, the overstatement of oil and gas reserves and manipulation of the California energy market. Formal discovery in the consolidated lawsuit is currently stayed.

Derivative Litigation. Since 2002, six shareholder derivative actions have also been filed. Two of these actions were filed in federal court in Houston; two of these actions were filed in state court in Houston; and two of these derivative actions were filed in Delaware Chancery Court. *The Houston federal court cases:* The first federal court case was filed in 2002 and the second was filed in 2004. The 2002 federal court case generally alleges the same claims pled in the consolidated shareholder class action described above, with the exception that there are no allegations related to the overstatement of oil and gas reserves. The 2004 federal court case includes allegations related to the overstatement of oil and gas reserves, in addition to the allegations alleged in the 2002 federal court case. The two federal court actions in Houston are both currently stayed. *The Houston state court cases:* The two state court actions in Houston have been consolidated. The plaintiffs in those cases originally alleged that the manipulation of California gas prices exposed us to claims of antitrust conspiracy, FERC penalties and erosion of share value. The plaintiffs in the consolidated state court case recently amended their petition to add claims of unjust enrichment of certain former executives allegedly attributable to round trip trading and restructuring of energy contracts and breach of fiduciary duty claims for failure to recover 2001 compensation paid to certain officers. Discovery is ongoing in this case. *The Delaware Chancery Court cases:* The first of these two cases was filed in 2002, and generally alleges the same claims pled in the consolidated shareholder class action described above, with the exception that there were no allegations related to the overstatement of oil and gas reserves. This lawsuit was voluntarily dismissed by plaintiffs in September 2005. The second Delaware derivative case was filed in April 2005 and seeks to recover the compensation paid to a former executive in 2001 alleging unjust enrichment allegedly attributable to round trip trading and restructuring of energy contracts and breach of fiduciary duty claims for failure to seek recovery of the 2001 compensation. Defendants have a motion pending seeking dismissal of this lawsuit based upon demand futility.

ERISA Class Action Suits. In December 2002, a purported class action lawsuit entitled *William H. Lewis, III v. El Paso Corporation, et al.* was filed in the U.S. District Court for the Southern District of Texas alleging generally that our direct and indirect communications with participants in the El Paso Corporation Retirement Savings Plan included misrepresentations and omissions that caused members of the class to hold and maintain investments in El Paso stock in violation of the Employee Retirement Income Security Act (ERISA). That lawsuit was subsequently amended to include allegations relating to our reporting of natural gas and oil reserves. Discovery in this lawsuit is currently stayed.

We and our representatives have insurance coverages that are applicable to each of these shareholder, derivative and ERISA lawsuits. There are certain deductibles and co-pay obligations under some of those insurance coverages for which we have established certain accruals we believe are adequate.

Cash Balance Plan Lawsuit. In December 2004, a lawsuit entitled *Tomlinson, et al. v. El Paso Corporation and El Paso Corporation Pension Plan* was filed in U.S. District Court for Denver, Colorado. The lawsuit seeks class action status and alleges that the change from a final average earnings formula pension plan to a cash balance pension plan, the accrual of benefits under the plan, and the communications about the change violate the ERISA and/or the Age Discrimination in Employment Act. Our costs and legal exposure related to this lawsuit are not currently determinable.

Retiree Medical Benefits Matters. We currently serve as the plan administrator for a medical benefits plan that covers a closed group of retirees of the Case Corporation who retired on or before June 30, 1994. Case was formerly a subsidiary of Tenneco, Inc. that was spun off prior to our acquisition of Tenneco in 1996. In connection with the Tenneco-Case Reorganization Agreement of 1994, Tenneco assumed the obligation to provide certain medical and prescription drug benefits to eligible retirees and their spouses. We assumed this obligation as a result of our merger with Tenneco. However, we believe that our liability for these benefits is limited to certain maximums, or caps, and costs in excess of these maximums are assumed by plan participants. In 2002, we and Case were sued by individual retirees in federal court in Detroit, Michigan in an action entitled *Yolton et al. v. El Paso Tennessee Pipeline Co. and Case Corporation*. The suit alleges, among other things, that El Paso and Case violated ERISA, and that they should be required to pay all amounts above the cap. Although such amounts will vary over time, the amounts above the cap have recently been approximately $1.8 million per month. Case further filed claims against El Paso asserting that El Paso is obligated to indemnify, defend, and hold Case harmless for the amounts it would be required to pay. In February 2004, a judge ruled that Case would be required to pay the amounts incurred above the cap. Furthermore, in September 2004, a judge ruled that pending resolution of this matter, El Paso must indemnify and reimburse Case for the monthly amounts above the cap. These rulings have been appealed and oral argument is scheduled for December 2005. In the meantime, El Paso will indemnify Case for any payments Case makes above the cap. While we believe we have meritorious defenses to the plaintiffs' claims and to Case's crossclaim, if we were required to ultimately pay for all future amounts above the cap, and if Case were not found to be responsible for these amounts, our exposure could be as high as $400 million, on an undiscounted basis.

Natural Gas Commodities Litigation. Beginning in August 2003, several lawsuits were filed against El Paso and El Paso Marketing L.P. (EPM), formerly El Paso Merchant Energy L.P., our affiliate, in which plaintiffs alleged, in part, that El Paso, EPM and other energy companies conspired to manipulate the price of natural gas by providing false price reporting information to industry trade publications that published gas indices. Those cases, all filed in the United States District Court for the Southern District of New York, are as follows: *Cornerstone Propane Partners, L.P. v. Reliant Energy Services Inc., et al.*; *Roberto E. Calle Gracey v. American Electric Power Company, Inc., et al.*; and *Dominick Viola v. Reliant Energy Services Inc., et al.* In December 2003, those cases were consolidated with others into a single master file in federal court in New York for all pre-trial purposes. In September 2004, the court dismissed El Paso from the master litigation. In September 2005, the court certified the class to include all persons who purchased or sold NYMEX natural gas futures between January 1, 2000 and December 31, 2002. EPM and approximately 27 other energy companies remain in the litigation. In January 2005, a purported class action lawsuit styled *Leggett et al. v. Duke Energy Corporation et al.* was filed against El Paso, EPM and a number of other energy companies in the Chancery Court of Tennessee for the Twenty-Fifth Judicial District at Somerville on behalf of all residential and commercial purchasers of natural gas in the state of Tennessee. Plaintiffs allege the defendants conspired to manipulate the price of natural gas by providing false price reporting information to industry trade publications that published gas indices. Two similar actions have been filed in state court in Wyandotte County, Kansas on behalf of purchasers of natural gas in that state: *Farmland Industries, Inc. v. Oneok Inc.* was filed in July 2005 and *Learjet, Inc. v. Oneok Inc.* was filed in September 2005. We have also had similar purported class claims filed in the U.S. District Court for the Eastern District of California by and on behalf of commercial and residential customers in that state. The case of *Texas-Ohio Energy, Inc. v. CenterPoint Energy, Inc., et al.* was filed in November 2003; *Fairhaven Power v. El Paso Corporation, et al.* was filed in September 2004; *Utility Savings and Refund Services, et al. v. Reliant Energy, et al.* was filed in December 2004; *Abelman Art Glass, et al. v. Encana Corporation, et al.* was filed in December 2004; and *Ever-Bloom Inc. v. AEP Energy Services Inc. et al* was filed in June 2005. The defendants' motion to dismiss in the *Texas-Ohio* matter has been granted and similar motions are anticipated in the other cases. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

Grynberg. In 1997, a number of our subsidiaries were named defendants in actions brought by Jack Grynberg on behalf of the U.S. Government under the False Claims Act. Generally, these complaints allege an industry-wide conspiracy to underreport the heating value as well as the volumes of the natural gas produced from federal and Native American lands, which deprived the U.S. Government of royalties due to the alleged mismeasurement. The plaintiff seeks royalties along with interest, expenses, and punitive damages. The plaintiff also seeks injunctive relief with regard to future gas measurement practices. No monetary relief has been specified in this case. These matters have been consolidated for pretrial purposes (*In re: Natural Gas Royalties Qui Tam Litigation,* U.S. District Court for the District of Wyoming, filed June 1997). Motions to dismiss were argued before a representative appointed by the court. In May 2005, the representative issued its recommendation, which if adopted by the district court judge, will result in the dismissal on jurisdictional grounds of six of the seven *Qui Tam* actions filed by Grynberg against El Paso subsidiaries. The seventh case involves only a few midstream entities owned by El Paso, which have meritorious defenses to the underlying claims. If the district court judge adopts the representative's recommendations, an appeal by the plaintiff of the district court's order is likely. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

Will Price (formerly Quinque). A number of our subsidiaries are named as defendants in *Will Price, et al. v. Gas Pipelines and Their Predecessors, et al.,* filed in 1999 in the District Court of Stevens County, Kansas. Plaintiffs allege that the defendants mismeasured natural gas volumes and heating content of natural gas on non-federal and non-Native American lands and seek to recover royalties that they contend they should have received had the volume and heating value of natural gas produced from their properties been differently measured, analyzed, calculated and reported, together with prejudgment and postjudgment interest, punitive damages, treble damages, attorneys' fees, costs and expenses, and future injunctive relief to require the defendants to adopt allegedly appropriate gas measurement practices. No monetary relief has been specified in this case. Plaintiffs' motion for class certification of a nationwide class of natural gas working interest owners and natural gas royalty owners was denied in April 2003. Plaintiffs were granted leave to file a Fourth Amended Petition, which narrows the proposed class to royalty owners in wells in Kansas, Wyoming and Colorado and removes claims as to heating content. A second class action petition has since been filed as to the heating content claims. Motions for class certification have been briefed and argued in both proceedings, and the parties are awaiting the court's ruling. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

Hurricane Litigation. One of our affiliates has been named in two class action petitions for damages filed in the United States District Court for the Eastern District of Louisiana against all oil and gas pipeline and production companies that dredged pipeline canals, installed transmission lines or drilled for oil and gas in the marshes of coastal Louisiana. The lawsuits, *George Barasich, et al. v. Columbia Gulf Transmission Company, et al.* and *Charles Villa Jr., et al. v. Columbia Gulf Transmission Company, et al.* assert that the defendants caused erosion and land loss which destroyed critical protection against hurricane surges and winds and was a substantial cause of the loss of life and destruction of property. The first lawsuit alleges damages associated with Hurricane Katrina. The second lawsuit alleges damages associated with Hurricanes Katrina and Rita. Our costs and legal exposures related to these lawsuits and claims are not currently determinable.

Bank of America. We are a named defendant, along with Burlington Resources, Inc. (Burlington), in two class action lawsuits styled as *Bank of America, et al. v. El Paso Natural Gas Company, et al.,* and *Deane W. Moore, et al. v. Burlington Northern, Inc., et al.,* each filed in 1997 in the District Court of Washita County, State of Oklahoma and subsequently consolidated by the court. The plaintiffs have filed reports alleging damages of approximately $353 million, which includes alleged royalty underpayments from 1982 to the present on natural gas produced from specified wells in Oklahoma, plus interest from the time such amounts were allegedly due. The plaintiffs have also requested punitive damages. The court has certified the plaintiff classes of royalty and overriding royalty interest owners. Trial of the consolidated class action commenced on October 10, 2005 and is proceeding. While Burlington accepted our tender of the defense of these cases in 1997, pursuant to the spin-off agreement entered into in 1992 between EPNG and Burlington, and had been defending the matter since that time, at the end of 2003 it asserted contractual claims for indemnity against us. A third action, styled *Bank of America, et al. v. El Paso Natural Gas and Burlington Resources Oil and Gas Company,* was filed in October 2003 in the District Court of Kiowa County, Oklahoma asserting similar claims as to specified shallow wells in Oklahoma, Texas and New Mexico. Defendants succeeded in transferring this action to Washita County. A class has not been certified. We have filed an action styled *El Paso Natural Gas Company v. Burlington Resources, Inc. and Burlington Resources Oil and Gas Company, L.P.* against Burlington in state court in Harris County relating to the indemnity issues between Burlington and us. That action is currently stayed by agreement of the parties. We believe we have substantial defenses to the plaintiffs' claims as well as to the claims for indemnity by Burlington.

Araucaria. We own a 60 percent interest in a 484 MW gas-fired power project known as the Araucaria project located near Curitiba, Brazil. The Araucaria project has a 20-year power purchase agreement (PPA) with a government-controlled regional utility. In December 2002, the utility ceased making payments to the project and, as a result, the Araucaria project and the utility are currently involved in international arbitration over the PPA, which is scheduled for hearing in the first quarter of 2006. A Curitiba court has ruled that the arbitration clause in the PPA is invalid. The project company is appealing this ruling. Our investment in the Araucaria project was $189 million at September 30, 2005. We have political risk insurance that covers a substantial portion of our investment in the project. Based on the future outcome of our dispute under the PPA and depending on our ability to collect amounts from the utility or under our political risk insurance policies, we could be required to write down the value of our investment.

Macae. We own a 928 MW gas-fired power plant known as the Macae project located near the city of Macae, Brazil. The Macae project revenues are derived, in part from minimum capacity and revenue payments made by Petrobras under a participation agreement that extends through August 2007. Petrobras has filed a notice of arbitration that seeks rescission of the participation agreement and reimbursement of some or all of the capacity payments that it has made. The final arbitration hearing took place in October 2005 and we await a final ruling. If such claim were successful, it would result in a termination of the minimum revenue payments as well as Petrobras' obligation to provide a firm gas supply to the project through 2012. Beginning in December 2004, and through the third quarter of 2005, Petrobras has failed to make payments due under the participation agreement. Actions have been filed in Brazilian courts and before an arbitration panel to address Petrobras' payment obligations during the pendency of the arbitration proceedings. Although various appellate proceedings in such actions are outstanding, the arbitration panel has required Petrobras to pay past due amounts and additional amounts owed during the arbitration process, subject to Macae's obligation to post a bank guarantee as security for any repayment obligation if Petrobras prevails in the dispute. During the first nine months of 2005 we have not recognized approximately $152 million of revenues under our participation agreement, because of the uncertainty about their collectibility. We believe we have substantial defenses to the claims of Petrobras and continue to vigorously defend our legal rights. In addition, we will continue to seek reasonable settlements of this dispute, including the restructuring of the participation agreement or the sale of the plant. Macae has non-recourse debt of approximately $234 million at September 30, 2005, and Petrobras' non-payment has created an event of default under the applicable loan agreements. As a result, we have classified the debt as current. We also have restricted cash balances of approximately $7 million as of September 30, 2005, which are reflected in current assets, related to required debt service reserve balances. In light of the default of Petrobras under the participation agreement and the potential inability of Macae to continue to make ongoing payments under its loan agreements, one or more of the lenders could exercise remedies under the loan agreements in the future, one of which could be an acceleration of the amounts owed under the loan agreements which could ultimately result in the lenders foreclosing on the Macae project.

As a result of continued negotiations and discussions with Petrobras regarding this dispute, we may sell our investment in the Macae power facility to Petrobras in connection with the eventual resolution of this dispute or exchange our interest in the plant for Brazilian production properties owned by Petrobras. In the second quarter of 2005, we recorded a $276 million impairment charge on our investment and also reserved $18 million of related receivables based on information regarding the potential value we may receive from the resolution of this matter. In the event that the lenders call the loans and ultimately foreclose on the project, we may incur additional losses of up to approximately $185 million. As new information becomes available or future material developments occur, we will reassess the carrying value of our interests in this project.

MTBE. In compliance with the 1990 amendments to the Clean Air Act, we used the gasoline additive methyl tertiary-butyl ether (MTBE) in some of our gasoline. We have also produced, bought, sold and distributed MTBE. A number of lawsuits have been filed throughout the U.S. regarding MTBE's potential impact on water supplies. We and some of our subsidiaries are among the defendants in over 60 such lawsuits. As a result of a ruling issued in March 2004, these suits have been consolidated for pre-trial purposes in multi-district litigation in the U.S. District Court for the Southern District of New York. The plaintiffs, certain state attorneys general and various water districts, seek remediation of their groundwater, prevention of future contamination, a variety of compensatory damages, punitive damages, attorney's fees, and court costs. The plaintiff states of California and New Hampshire have filed an appeal to the 2nd Circuit Court of Appeals challenging the removal of the cases from state to federal court. That appeal is pending. In April 2005, the judge denied a motion by defendants to dismiss the lawsuits. In that opinion the Court recognized, for certain states, a potential commingled product market share basis for collective liability. Our costs and legal exposure related to these lawsuits are not currently determinable.

Wise Arbitration. William Wise, our former Chief Executive Officer, initiated an arbitration proceeding alleging that we breached his employment agreement, as well as several other alleged agreements by failing to make certain payments to him following his departure from El Paso in 2003. Although Mr. Wise initially sought approximately $20 million in additional compensation, Mr. Wise revised his claims and sought cash compensation in excess of $15 million, as well as injunctive relief that would require us to make certain future payments. The arbitration panel issued an interim decision in July 2005 generally finding that Mr. Wise was not entitled to any payments other than those set forth in his employment agreement that governed his post employment compensation. A final decision was issued in September 2005 confirming the interim decision.

Government Investigations

Wash Trades. In June 2002, we received an informal inquiry from the SEC regarding the issue of round trip trades. Although we do not believe any round trip trades occurred, we submitted data to the SEC in July 2002. In July 2002, we received a federal grand jury subpoena for documents concerning round trip or wash trades. We have complied with those requests. We have also cooperated with the U.S. Attorney regarding an investigation of specific transactions executed in connection with hedges of our natural gas and oil production and the restatement of the accounting for such hedges. On May 24, 2005, we received a subpoena from the SEC requesting the production of documents related to such production hedges. We are cooperating with the SEC investigation.

Price Reporting. In October 2002, the FERC issued data requests regarding price reporting of transactional data to the energy trade press. We provided information to the FERC, the Commodity Futures Trading Commission (CFTC) and the U.S. Attorney in response to their requests. In the first quarter of 2003, we announced a settlement with the CFTC of the price reporting matter providing for the payment of a civil monetary penalty by EPM of $20 million, $10 million of which is payable in 2006, without admitting or denying the CFTC holdings in the order. We are continuing to cooperate with the U.S. Attorney's investigation of this matter.

Reserve Revisions. In March 2004, we received a subpoena from the SEC requesting documents relating to our December 31, 2003 natural gas and oil reserve revisions. We have also received federal grand jury subpoenas for documents with regard to these reserve revisions and we cooperated with the U.S. Attorney's investigation related to this matter. In June 2005, we were informed that the U.S. Attorney's office closed this investigation and will not pursue prosecution at this time. We will continue to cooperate with the SEC in its investigation related to such reserve revisions.

Iraq Oil Sales. In September 2004, The Coastal Corporation (now known as El Paso CGP Company, which we acquired in January 2001) received a subpoena from the grand jury of the U.S. District Court for the Southern District of New York to produce records regarding the United Nations' Oil for Food Program governing sales of Iraqi oil. The subpoena seeks various records related to transactions in oil of Iraqi origin during the period from 1995 to 2003. In November 2004, we received an order from the SEC to provide a written statement and to produce certain documents in connection with The Coastal Corporation's and El Paso's participation in the Oil for Food Program. In June 2005, we received an additional request for documents and information from the SEC. We have also received informal requests for information and documents from the United States Senate's Permanent Subcommittee of Investigations and the House of Representatives International Relations Committee related to Coastal's purchases of Iraqi crude under the Oil for Food Program. In October 2005, a grand jury sitting in the Southern District of New York handed down an indictment against Oscar S. Wyatt, Jr., a former CEO and Chairman of the Coastal Corporation. Also in October 2005, the Independent Inquiry Committee into the United Nations' Oil for Food Program issued its final report. The report states that $201,877 in surcharges were paid with respect to a single contract entered into by Coastal Petroleum NV (CPNV). The report lists Oscar Wyatt as the non-contractual beneficiary of the contract. The report indicates that the payments were made by two other individuals or entities and does not contend that CPNV paid that surcharge.

Carlsbad. In August 2000, a main transmission line owned and operated by EPNG ruptured at the crossing of the Pecos River near Carlsbad, New Mexico. Twelve individuals at the site were fatally injured. In June 2001, the U.S. Department of Transportation's Office of Pipeline Safety (DOT) issued a Notice of Probable Violation and Proposed Civil Penalty to EPNG. The Notice alleged violations of DOT regulations, proposed fines totaling $2.5 million and proposed corrective actions. In April 2003, the National Transportation Safety Board issued its final report on the rupture, finding that the rupture was probably caused by internal corrosion that was not detected by EPNG's corrosion control program. In December 2003, this matter was referred by the DOT to the Department of Justice (DOJ). We entered into a tolling agreement with the DOJ to attempt to reach resolution of this civil proceeding and have recently extended that agreement. In addition, we, EPNG and several of its current and former employees had received several federal grand jury subpoenas for documents or testimony related to the Carlsbad rupture. In August 2005, we received a letter from the DOJ stating that the United States is not pursuing any criminal prosecutions associated with the rupture.

In addition to the above matters, we and our subsidiaries and affiliates are named defendants in numerous lawsuits and governmental proceedings that arise in the ordinary course of our business. There are also other regulatory rules and orders in various stages of adoption, review and/or implementation, none of which we believe will have a material impact on us.

Rates and Regulatory Matters

EPNG Rate Case. In June 2005, EPNG filed a rate case with the FERC proposing an increase in revenues of 10.6 percent or $56 million over current tariff rates, new services and revisions to certain terms and conditions of existing services, including the adoption of a fuel tracking mechanism. The rate case would be effective January 1, 2006. In addition, the reduced tariff rates provided to EPNG's former full requirements customers under the terms of our FERC approved systemwide capacity allocation proceeding will expire. In July 2005, the FERC accepted certain of the proposed tariff revisions, including the adoption of a fuel tracking mechanism and set the rate case for hearing and technical conference. Technical conferences have now been held and settlement discussions are ongoing. EPNG also filed a settlement that will delay the effective date of the proposed new services and other provisions until April 1, 2006. The outcome of this rate case cannot be predicted with certainty at this time.

Other Contingencies

Navajo Nation. Nearly 900 looped pipeline miles of the north mainline of our EPNG pipeline system are located on property inside the Navajo Nation. Our real property interests, such as easements, leases and rights-of-way, located on Navajo Nation trust lands expired on October 17, 2005. Under the expiring agreements, we paid approximately $2 million per year to the Nation. To renew those rights, we have extended a cash offer that increases that compensation to approximately $138 million in cash and restricted common stock plus non-cash consideration, including a collaborative project to benefit the Nation, totaling another $60 million, over the next 20 years. We continue to negotiate with the Navajo Nation, but the Navajo Nation has made a demand of more than ten times the existing fee. In an effort to resolve the current impasse in the negotiations, we have also filed an application with the Department of the Interior requesting the agency renew our federal right-of-way on Navajo Nation lands. Recognizing we are not the only pipeline facing this issue, the Energy Policy Act of 2005 includes a provision that calls for a comprehensive study of energy infrastructure right-of-way on tribal lands. The study, to be conducted jointly by the Departments of Energy and the Interior must be submitted to Congress by August 2006. Historically, we have continued renewal negotiations with the Navajo Nation substantially beyond the prior easement's expiration, without litigation or interruption to our operations. While we currently do not anticipate the expiration of the right-of-way will lead to any interruption in service to our customers, the impact of this impasse is uncertain. As our renewal efforts continue, we may incur litigation and other costs and, ultimately, higher fees. Although the FERC has rejected a request made in the rate case filed in June 2005 for a tracking mechanism that would have provided an assurance of recovery of the cost of the Navajo right-of-way, the FERC did invite us to seek permission to include the cost of the right-of-way in our pending rate case if the final cost becomes known and measurable within a reasonable time after the close of the test period on December 31, 2005.

Brazilian Matters. We own a number of interests in various production properties, power and pipeline assets in Brazil, including our Macae project discussed previously. Our total investment in Brazil was approximately $1.3 billion as of September 30, 2005. In a number of our assets and investments, Petrobras either serves as a joint owner, a customer or a shipper to the asset or project. Although we have no material current disputes with Petrobras with regard to the ownership or operation of our production and pipeline assets, current disputes on the Macae power plant between us and Petrobras may negatively impact these investments and the impact could be material. In addition, although the Macae power plant is currently dispatching only small quantities of electricity, a recent rupture in the local distribution company's pipeline that supplies it gas has resulted in the plant temporarily being unable to generate electricity. We are currently assessing the time it will take for the pipeline to be placed back into full operation. We also own an investment in the Porto Velho power plant. The Porto Velho project is in the process of negotiating certain provisions of its power purchase agreements (PPA) with Eletronorte, including the amount of installed capacity, energy prices, take or pay levels, the term of the first PPA and other issues. In addition, in October 2004, the project experienced an outage with a steam turbine which resulted in a partial reduction in the plant's capacity. The project expects to repair the steam turbine by the first quarter of 2006. We are uncertain what impact this outage will have on the PPAs. Although the current terms of the PPAs and the ongoing contract negotiations do not indicate an impairment of our investment, we may be required to write down the value of our investment if these negotiations are resolved unfavorably. Our investment in Porto Velho was approximately $303 million at September 30, 2005.

For each of our outstanding legal and other contingent matters, we evaluate the merits of the case, our exposure to the matter, possible legal or settlement strategies and the likelihood of an unfavorable outcome. If we determine that an unfavorable outcome is probable and can be estimated, we establish the necessary accruals. While the outcome of these matters cannot be predicted with certainty and there are still uncertainties related to the costs we may incur, based upon our evaluation and experience to date, we believe we have established appropriate reserves for these matters. However, it is possible that new information or future developments could require us to reassess our potential exposure related to these matters and adjust our accruals accordingly. As of September 30, 2005, we had approximately $206 million accrued, net of related insurance receivables, for all outstanding legal and other contingent matters.

Environmental Matters

We are subject to federal, state and local laws and regulations governing environmental quality and pollution control. These laws and regulations require us to remove or remedy the effect on the environment of the disposal or release of specified substances at current and former operating sites. As of September 30, 2005, we had accrued approximately $369 million, including approximately $357 million for expected remediation costs and associated onsite, offsite and groundwater technical studies, and approximately $12 million for related environmental legal costs. Of the $369 million accrual, $86 million was reserved for facilities we currently operate, and $283 million was reserved for non-operating sites (facilities that are shut down or have been sold) and Superfund sites.

Our reserve estimates range from approximately $369 million to approximately $545 million. Our accrual represents a combination of two estimation methodologies. First, where the most likely outcome can be reasonably estimated, that cost has been accrued ($79 million). Second, where the most likely outcome cannot be estimated, a range of costs is established ($290 million to $466 million) and if no one amount in that range is more likely than any other, the lower end of the expected range has been accrued. Our environmental remediation projects are in various stages of completion. The liabilities we have recorded reflect our current estimates of amounts we will expend to remediate these sites. However, depending on the stage of completion or assessment, the ultimate extent of contamination or remediation required may not be known. As additional assessments occur or remediation efforts continue, we may incur additional liabilities. By type of site, our reserves are based on the following estimates of reasonably possible outcomes.

	September 30, 2005	
Sites	**Expected**	**High**
	(In millions)	
Operating	$ 86	$ 97
Non-operating	253	387
Superfund	30	61
Total	$369	$545

Below is a reconciliation of our accrued liability from January 1, 2005, to September 30, 2005 (in millions):

Balance as of January 1, 2005	$380
Additions/adjustments for remediation activities	33
Payments for remediation activities	(44)
Balance as of September 30, 2005	$369

For the last three months of 2005, we estimate that our total remediation expenditures will be approximately $23 million. In addition, we expect to make capital expenditures for environmental matters of approximately $95 million in the aggregate for the years 2005 through 2009. These expenditures primarily relate to compliance with clean air regulations.

Polychlorinated Biphenyls (PCB) Cost Recoveries. Pursuant to a consent order executed by Tennessee Gas Pipeline (TGP), our subsidiary, in May 1994, with the Environmental Protection Agency (EPA), TGP has been conducting various remediation activities at certain of its compressor stations associated with the presence of PCBs, and certain other hazardous materials. In May 1995, following negotiations with its customers, TGP filed an agreement with the FERC that established a mechanism for recovering a substantial portion of the environmental costs identified in its PCB remediation project. The agreement, which was approved by the FERC in November 1995, provided for a PCB surcharge on firm and interruptible customers' rates to pay for eligible remediation costs, with these surcharges to be collected over a defined collection period. TGP has received approval from the FERC to extend the collection period, which is now currently set to expire in June 2006. The agreement also provided for bi-annual audits of eligible costs. As of September 30, 2005, TGP had pre-collected PCB costs of approximately $130 million. The pre-collected amount will be reduced by future eligible costs incurred for the remainder of the remediation project. To the extent actual eligible expenditures are less than the amounts pre-collected, TGP will refund to its customers the difference, plus carrying charges incurred up to the date of the refunds. As of September 30, 2005, TGP has recorded a regulatory liability (included in other non-current liabilities on its balance sheet) of $104 million for the estimated future refund obligations.

CERCLA Matters. We have received notice that we could be designated, or have been asked for information to determine whether we could be designated, as a Potentially Responsible Party (PRP) with respect to 46 active sites under the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) or state equivalents. We have sought to resolve our liability as a PRP at these sites through indemnification by third-parties and settlements which provide for payment of our allocable share of remediation costs. As of September 30, 2005, we have estimated our share of the remediation costs at these sites to be between $30 million and $61 million. Since the clean-up costs are estimates and are subject to revision as more information becomes available about the extent of remediation required, and because in some cases we have asserted a defense to any liability, our estimates could change. Moreover, liability under the federal CERCLA statute is joint and several, meaning that we could be required to pay in excess of our pro rata share of remediation costs. Our understanding of the financial strength of other PRPs has been considered, where appropriate, in estimating our liabilities. Accruals for these issues are included in the previously indicated estimates for Superfund sites.

It is possible that new information or future developments could require us to reassess our potential exposure related to environmental matters. We may incur significant costs and liabilities in order to comply with existing environmental laws and regulations. It is also possible that other developments, such as increasingly strict environmental laws, regulations, and orders of regulatory agencies, as well as claims for damages to property and the environment or injuries to employees and other persons 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 related to the ultimate costs we may incur, based upon our evaluation and experience to date, we believe our reserves are adequate.

Guarantees

We are involved in various joint ventures and other ownership arrangements that sometimes require additional financial support that results in the issuance of financial and performance guarantees. See our 2004 Annual Report on Form 10-K, as amended, for a description of these commitments. As of September 30, 2005, we had approximately $29 million of both financial and performance guarantees not otherwise reflected in our financial statements. We also periodically provide indemnification arrangements related to assets or businesses we have sold. As of September 30, 2005, we had accrued $56 million related to these arrangements.

11. Retirement Benefits

The components of net benefit cost for our pension and postretirement benefit plans for the periods ended September 30 are as follows:

	Quarters Ended September 30,				Nine Months Ended September 30,			
	Pension Benefits		Other Postretirement Benefits		Pension Benefits		Other Postretirement Benefits	
	2005	2004	2005	2004	2005	2004	2005	2004
	(In millions)				(In millions)			
Service cost	$ 5	$ 8	$—	$—	$ 17	$ 24	$—	$—
Interest cost	29	30	7	9	87	91	22	25
Expected return on plan assets	(42)	(47)	(3)	(3)	(126)	(142)	(9)	(9)
Amortization of net actuarial loss	16	12	—	1	48	36	—	3
Amortization of transition obligation	—	—	2	2	—	—	6	6
Amortization of prior service cost[1]	—	(1)	—	—	(2)	(3)	—	—
Settlements, curtailment and special termination benefits[2]	—	(5)	—	—	—	(5)	—	—
Net benefit cost	$ 8	$ (3)	$ 6	$ 9	$ 24	$ 1	$19	$25

(1) As permitted, the amortization of any prior service cost is determined using a straight-line amortization of the cost over the average remaining service period of employees expected to receive benefits under the plan.

(2) We recognized curtailments in 2004 related to a reduction in the number of employees that participate in our pension and other postretirement plans, which resulted from our various asset sales and employee severance efforts in 2004.

In 2004, we adopted FSP No. 106-2, *Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003.* This pronouncement required us to record the impact of the Medicare Prescription Drug, Improvement and Modernization Act of 2003 on our postretirement benefit plans that provide drug benefits that are covered by that legislation. The adoption of FSP No. 106-2 decreased our accumulated postretirement benefit obligation by $49 million. In addition, it reduced our net periodic benefit cost by approximately $5 million for the first nine months of 2005. Our actual and expected contributions for 2005 were not reduced by subsidies under this legislation.

We made $63 million and $59 million of cash contributions to our Supplemental Executive Retirement Plan (SERP) and other postretirement plans during the nine months ended September 30, 2005 and 2004. We expect to contribute an additional $2 million to the SERP and $10 million to our other postretirement plans for the remainder of 2005. Contributions to our other retirement benefit plans will be less than $1 million in 2005.

12. Capital Stock

Common Stock

In August 2005, we issued approximately 13.6 million shares of common stock. The common stock was issued to the holders of $272 million of notes which originally formed a portion of our 9.0% equity security units in settlement of their commitment to purchase the shares. For a further discussion of the equity security units, see Note 9 and our 2004 Annual Report on Form 10-K, as amended.

Convertible Perpetual Preferred Stock

In April 2005, we issued $750 million of convertible perpetual preferred stock. Cash dividends on the preferred stock are paid quarterly at the rate of 4.99% per annum. Each share of the preferred stock is convertible at the holder's option, at any time, subject to adjustment, into 76.7754 shares of our common stock under certain conditions. This conversion rate represents an equivalent conversion price of approximately

$13.03 per share. The conversion rate is subject to adjustment based on certain events which include, but are not limited to, fundamental changes in our business such as mergers or business combinations as well as distributions of our common stock or adjustments to the current rate of dividends on our common stock. We will be able to cause the preferred stock to be converted into common stock after five years if our common stock is trading at a premium of 130 percent to the conversion price.

The net proceeds of $723 million from the issuance of the preferred stock, together with cash on hand, was used to prepay our Western Energy Settlement of approximately $442 million in April 2005, and to pay the redemption price (an aggregate of $300 million plus accrued dividends of $3 million) of the 6 million outstanding shares of 8.25% Series A cumulative preferred stock of our subsidiary, El Paso Tennessee Pipeline Co. (EPTP), in May 2005.

Dividends

During the nine months ended September 30, 2005, we paid dividends of approximately $77 million to common stockholders. The dividends on our common stock were treated as a reduction of additional paid-in-capital since we currently have an accumulated deficit. We have also paid dividends of approximately $26 million subsequent to September 30, 2005. On October 27, 2005, the Board of Directors declared a quarterly dividend of $0.04 per share on the company's outstanding common stock. The dividend will be payable on January 3, 2006 to shareholders of record on December 2, 2005.

On July 1, 2005 and October 3, 2005, we paid dividends of $10.53 and $12.475 per share on our 4.99% convertible perpetual preferred stock. On October 27, 2005, the Board of Directors declared the quarterly dividend of $12.475 per share on the company's outstanding preferred stock. The dividend will be payable on January 3, 2006 to the shareholders of record on December 15, 2005.

We expect dividends paid on our common and preferred stock in 2005 will be taxable to our stockholders because we anticipate that these dividends will be paid out of current or accumulated earnings and profits for tax purposes.

13. Business Segment Information

Our regulated business consists of our Pipelines segment, while our non-regulated businesses consist of our Production, Marketing and Trading, Power and Field Services segments. Our segments are strategic business units that provide a variety of energy products and services. They are managed separately as each segment requires different technology and marketing strategies. Our corporate operations include our general and administrative functions, as well as a telecommunications business and various other contracts and assets, all of which are immaterial. During the second quarter of 2005, we reflected our south Louisiana gathering and processing assets, which were part of our Field Services segment, as discontinued operations. Our operating results for the quarter and nine months ended September 30, 2005 reflect these operations as discontinued. Prior period amounts have not been adjusted as these operations were not material to prior period results or historical trends.

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

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2005	2004	2005	2004
	(In millions)			
Total EBIT	$ (87)	$ 277	$ 424	$ 1,095
Interest and debt expense	(344)	(396)	(1,034)	(1,229)
Distributions on preferred interests of consolidated subsidiaries	—	(6)	(9)	(18)
Income taxes	108	(77)	165	(135)
Loss from continuing operations	$(323)	$(202)	$ (454)	$ (287)

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

	Regulated	Non-regulated					
Quarter Ended September 30,	Pipelines	Production	Marketing and Trading	Power	Field Services	Corporate[1]	Total
			(In millions)				
2005							
Revenues from external customers	$630	$155[2]	$ (95)	$ 45	$ 38	$ 15	$ 788
Intersegment revenues	16	294[2]	(294)	15	7	(16)	22[3]
Operation and maintenance	218	94	14	55	29	80	490
Depreciation, depletion and amortization	108	153	1	6	1	6	275
Loss on long-lived assets	—	—	—	—	3	—	3
Operating income (loss)	$207	$167	$(404)	$(16)	$ (26)	$(79)	$ (151)
Earnings (losses) from unconsolidated affiliates	51	—	—	(42)	4	—	13
Other income, net	14	2	6	17	—	12	51
EBIT	$272	$169	$(398)	$(41)	$ (22)	$(67)	$ (87)
2004							
Revenues from external customers	$582	$ 92[2]	$ 176	$188	$ 370	$ 21	$1,429
Intersegment revenues	22	308[2]	(296)	(7)	56	(83)	—
Operation and maintenance	204	96	15	102	19	39	475
Depreciation, depletion and amortization	104	136	4	14	3	9	270
(Gain) loss on long-lived assets	—	—	—	77	506	(1)	582
Operating income (loss)	$218	$147	$(139)	$(48)	$(477)	$(56)	$ (355)
Earnings from unconsolidated affiliates	43	1	—	25	548	—	617
Other income (expense), net	7	2	1	16	(10)	(1)	15
EBIT	$268	$150	$(138)	$ (7)	$ 61	$(57)	$ 277

(1) Includes eliminations of intercompany transactions. Our intersegment revenues, along with our intersegment operating expenses, were incurred in the normal course of business between our operating segments. For the quarters ended September 30, 2005 and 2004, we recorded an intersegment revenue elimination of $16 million and $83 million and an operations and maintenance expense elimination of less than $1 million and $1 million, which is included in the "Corporate" column, to remove intersegment transactions.

(2) Revenues from external customers include gains and losses related to our hedging of price risk associated with our natural gas and oil production. Intersegment revenues represent sales to our Marketing and Trading segment, which is responsible for marketing our production.

(3) Relates to intercompany activities between our continuing and our discontinued operations.

Nine Months Ended September 30,	Regulated Pipelines	Non-regulated Production	Marketing and Trading	Power	Field Services	Corporate[1]	Total
			(In millions)				
2005							
Revenues from external customers	$2,012	$457[2]	$ 238	$ 236	$ 103	$ 66	$3,112
Intersegment revenues	55	883[2]	(823)	10	18	(79)	64[3]
Operation and maintenance	635	277	33	184	32	209	1,370
Depreciation, depletion and amortization	327	456	3	28	3	32	849
(Gain) loss on long-lived assets	(10)	—	—	388	10	(4)	384
Operating income (loss)	$ 831	$522	$(622)	$(411)	$ (29)	$(206)	$ 85
Earnings (losses) from unconsolidated affiliates	127	—	—	(129)	186	—	184
Other income, net	35	6	9	68	—	37	155
EBIT	$ 993	$528	$(613)	$(472)	$ 157	$(169)	$ 424
2004							
Revenues from external customers	$1,875	$369[2]	$ 544	$ 539	$1,090	$ 93	$4,510
Intersegment revenues	67	907[2]	(964)	85	151	(246)	—
Operation and maintenance	556	258	38	296	70	31	1,249
Depreciation, depletion and amortization	305	407	10	42	10	34	808
(Gain) loss on long-lived assets	(1)	—	—	333	514	(9)	837
Operating income (loss)	$ 826	$552	$(468)	$(196)	$ (460)	$ (50)	$ 204
Earnings from unconsolidated affiliates	117	4	—	65	616	—	802
Other income (expense), net	19	2	14	57	(32)	29	89
EBIT	$ 962	$558	$(454)	$ (74)	$ 124	$ (21)	$1,095

(1) Includes eliminations of intercompany transactions. Our intersegment revenues, along with our intersegment operating expenses, were incurred in the normal course of business between our operating segments. For the nine months ended September 30, 2005 and 2004, we recorded an intersegment revenue elimination of $79 million and $246 million and an operations and maintenance expense elimination of less than $1 million and $1 million, which is included in the "Corporate" column, to remove intersegment transactions.

(2) Revenues from external customers include gains and losses related to our hedging of price risk associated with our natural gas and oil production. Intersegment revenues represent sales to our Marketing and Trading segment, which is responsible for marketing our production.

(3) Relates to intercompany activities between our continuing operations and our discontinued operations.

Total assets by segment are presented below:

	September 30, 2005	December 31, 2004
	(In millions)	
Regulated		
Pipelines	$16,215	$15,988
Non-regulated		
Production	5,681	4,080
Marketing and Trading	4,258	2,404
Power	1,971	3,599
Field Services	145	686
Total segment assets	28,270	26,757
Corporate	3,235	4,520
Discontinued operations	197	106
Total consolidated assets	$31,702	$31,383

14. Investments in Unconsolidated Affiliates and Related Party Transactions

We hold investments in various unconsolidated affiliates which are accounted for using the equity method of accounting. Our principal equity method investees are international pipelines, interstate pipelines and power generation plants. Our income statement reflects our share of net earnings from unconsolidated affiliates, which includes income or losses directly attributable to the net income or loss of our equity investments as well as impairments and other adjustments. In addition, for investments we are in the process of selling, or for those that have been impaired in previous periods, we evaluate the income generated by the investment and record an amount that we believe is realizable. For losses, we assess whether such amounts have already been considered in a related impairment. Our net ownership interest and earnings (losses) from our unconsolidated affiliates are as follows:

	Net Ownership Interest	Earnings (Losses) from Unconsolidated Affiliates Quarter Ended September 30,		Earnings (Losses) from Unconsolidated Affiliates Nine Months Ended September 30,	
	September 30, 2005	2005	2004	2005	2004
	(Percent)	(In millions)			
Domestic:					
Enterprise Products Partners, L.P.[1]	—	$ —	$ —	$183	$ —
GulfTerra Energy Partners, L.P.[1]	—	—	544	—	607
Citrus	50	19	18	52	46
Midland Cogeneration Venture (MCV)[2]	44	(159)	(4)	(162)	(1)
Great Lakes Gas Transmission	50	15	14	46	50
Other Domestic Investments[3]	various	16	27	22	36
Total domestic		(109)	599	141	738
Foreign:					
Asia Investments[4]	various	110	13	42	54
Central American Investments[5]	various	—	4	(49)	7
PPN[6]	—	—	—	22	—
Other Foreign Investments	various	12	1	28	3
Total foreign		122	18	43	64
Total earnings from unconsolidated affiliates		$ 13	$617	$184	$802

(1) In the third quarter of 2004, we sold our remaining interest in GulfTerra to Enterprise for cash and equity interests in Enterprise and recognized a $507 million gain. In January 2005, we sold all of our remaining interests to Enterprise and recognized a $183 million gain.

(2) Includes our proportionate share of a significant impairment recorded by MCV during the third quarter of 2005. As a result of this impairment, our remaining investment in MCV consists solely of our share of MCV's accumulated other comprehensive income of approximately $78 million as of September 30, 2005.

(3) Other domestic investments includes our interest in the Javelina natural gas processing and pipeline assets. We sold Javelina in November 2005 and will record a gain of approximately $100 million in the fourth quarter.

(4) Consists of our investments in 12 power plants, including Korea Independent Energy Corporation (KIECO) (which we sold in the third quarter of 2005 and recorded a $109 million gain), Meizhou Wan Generating, Habibullah Power and Saba Power Company. Our proportionate share of earnings reported by our Asia investments was $5 million and $49 million, for the quarter and nine months ended September 30, 2005. We decreased our proportionate share of equity earnings for our Asia investments by $4 million and $23 million, for the quarter and nine months ended September 30, 2005, to reflect the amount of earnings we believe will be realized.

(5) Consists of our investments in 6 power plants. Our proportionate share of earnings reported by our Central American investments was $5 million and $13 million for the quarter and nine months ended September 30, 2005. We decreased our proportionate share of equity earnings for our Central America investments by $5 million for the quarter and nine months ended September 30, 2005, to reflect the amount of earnings we believe will be realized.

(6) We sold our interest in March 2005 and recorded a $22 million gain.

The table below reflects our recognized impairment charges and gains and losses on sales of equity investments that are included in earnings (losses) from unconsolidated affiliates for the periods ended September 30:

Investment	Quarter Ended September 30,	Nine Months Ended September 30,
	Pre-tax Gain (Loss) (In millions)	
2005		
Impairments		
Asia power investments[1]	$ —	$ (93)
Central American power investments[1]	—	(57)
Other foreign investments[1]	—	(17)
Midland Cogeneration Venture[2]	(159)	(162)
Gain on sale of KIECO	109	109
Gain on sale of PPN	—	22
Gain on sale of Enterprise	—	183
Other	11	8
	$ (39)	$ (7)
2004		
Impairments		
Milford power facility[1]	$ —	$ (2)
Power plants held for sale[1]	(15)	(50)
Gain on sale of GulfTerra interests	507	507
Other	14	9
	$ 506	$ 464

(1) We impaired our interests in these investments based on information received regarding the potential value we may receive when we sell the investments.

(2) Represents our proportionate share of losses from our investment in MCV, which substantially consists of our share of a significant impairment recorded by MCV during the third quarter of 2005.

The summarized financial information below includes our proportionate share of the operating results of our unconsolidated affiliates, including affiliates in which we hold a less than 50 percent interest as well as those in which we hold a greater than 50 percent interest for the periods ended September 30:

	Quarter Ended September 30,					Nine Months Ended September 30,				
	Citrus	MCV	Great Lakes	Other Investments	Total	Citrus	MCV	Great Lakes	Other Investments	Total
					(In millions)					
2005										
Operating results data										
Revenues	$66	$ 67	$32	$288	$453	$181	$ 194	$98	$ 732	$1,205
Operating expenses	27	475	15	221	738	75	509	43	529	1,156
Income (loss) from continuing operations	19	(418)	9	38	(352)	49	(343)	30	121	(143)
Net income (loss)[1]	19	(418)[2]	9	38	(352)	49	(343)[2]	30	121	(143)

	Quarter Ended September 30,					Nine Months Ended September 30,				
	Citrus	MCV	Great Lakes	Other Investments	Total	Citrus	MCV	Great Lakes	Other Investments	Total
					(In millions)					
2004										
Operating results data										
Revenues	$64	$ 72	$31	$422	$589	$178	$ 211	$99	$1,312	$1,800
Operating expenses	21	66	15	302	404	69	179	41	919	1,208
Income (loss) from continuing operations	18	(4)	9	80	103	44	(1)	33	244	320
Net income (loss)[1]	18	(4)	9	80	103	46	(1)	33	244	322

(1) Includes net income of $8 million and $3 million for the quarters ended September 30, 2005 and 2004, and $22 million and $24 million for the nine months ended September 30, 2005 and 2004, related to our proportionate share of affiliates in which we hold a greater than 50 percent interest.

(2) Includes $9 million and $26 million of earnings during the quarter and nine months ended September 30, 2005 attributable to transactions with El Paso which were eliminated.

We received distributions and dividends from our investments of $50 million and $72 million for each of the quarters ended September 30, 2005 and 2004, and $197 million and $240 million for the nine months ended September 30, 2005 and 2004.

Related Party Transactions

We enter into a number of transactions with our unconsolidated affiliates in the ordinary course of conducting our business. The following table shows the income statement impact on transactions with our affiliates for the periods ended September 30:

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2005	2004	2005	2004
		(In millions)		
Operating revenue	$26	$49	$118	$167
Cost of sales	4	31	10	91
Reimbursement for operating expenses	1	28	2	93
Other income	3	3	12	12

GulfTerra Energy Partners, L.P.

Prior to the sale of our interests in GulfTerra to Enterprise in September 30, 2004, our Field Services segment managed GulfTerra's daily operations and performed all of GulfTerra's administrative and operational activities under a general and administrative services agreement or, in some cases, separate operational agreements. GulfTerra contributed to our income through our general partner interest and our ownership of common and preference units. We did not have any loans to or from GulfTerra.

In December 2003, GulfTerra and a wholly owned subsidiary of Enterprise executed definitive agreements to merge and form the second largest publicly traded energy partnership in the United States. On July 29, 2004, GulfTerra's unitholders approved the adoption of its merger agreement with Enterprise which was completed in September 2004, which resulted in a gain of $507 million. In January 2005, we sold our remaining 9.9 percent interest in the general partner of Enterprise and approximately 13.5 million common units in Enterprise for $425 million, which resulted in a gain of approximately $183 million. We also sold our membership interest in two subsidiaries that own and operate natural gas gathering systems and the Indian Springs processing facility to Enterprise for $75 million, which resulted in a loss of approximately $1 million.

During 2004, our segments conducted transactions in the ordinary course of business with GulfTerra, including operational services and sales of natural gas under transportation contracts, the net financial impact of which are included in revenues. We incurred losses on our transportation contracts with GulfTerra, net of other revenues, of $5 million and $9 million for the quarter and nine months ended September 30, 2004. Expenses paid to GulfTerra were $24 million and $80 million and reimbursements from GulfTerra were $24 million and $69 million for the quarter and nine months ended September 30, 2004.

Contingent Matters that Could Impact Our Investments

Economic Conditions in the Dominican Republic. We have investments in power projects in the Dominican Republic with an aggregate exposure of approximately $57 million. We own an approximate 25 percent ownership interest in a 416 MW power generating complex known as Itabo. We also own an approximate 48 percent interest in a 67 MW heavy fuel oil fired power project known as the CEPP project. The country is emerging from an economic crisis that developed in 2003 resulting in a significant devaluation of the Dominican peso. As a result of these economic conditions, combined with the high prices on imported fuels, and due to their inability to pass through these high fuel costs to their consumers, the local distribution companies that purchase the electrical output of these facilities were delinquent in their payments to CEPP and Itabo, and to the other generating facilities in the Dominican Republic. The government of the Dominican Republic has signed an agreement with the IMF and World Bank that restores lending programs and provides for the recovery of the power sector. This led to the government's agreement to keep payments current and address the arrears to the generating companies. We continue to monitor the economic and payment situation in the Dominican Republic and as new information becomes available or future material developments arise, it is possible that future impairments of these investments may occur.

Bolivia. We own an eight percent interest in the Bolivia to Brazil pipeline in which we have approximately $96 million of exposure, including guarantees, as of September 30, 2005. During the second quarter of 2005, political disputes in Bolivia related to pressure to nationalize the energy industry led to the resignation of the president of Bolivia. Additionally, recent changes in Bolivian law also increased the combined rate of production taxes and royalties to 50 percent and required that existing exploration contracts be renegotiated. Further deterioration of the political environment in Bolivia could potentially lead to a disruption or cessation of the supply of gas from Bolivia and impact the payments that the Bolivia to Brazil pipeline receives from Petrobras. We continue to monitor the political situation in Bolivia and as new information becomes available or future material developments arise, it is possible that a future impairment of our investment may occur.

Berkshire Power Project. We own a 56 percent direct equity interest in a 261 MW power plant, Berkshire Power, located in Massachusetts. Berkshire's lenders have asserted that Berkshire is in default on its loan agreement (but no remedies have been exercised at this point). We supply natural gas to Berkshire under a fuel management agreement. Berkshire had the ability to delay payment of 33 percent of the amounts due to us under the fuel supply agreement, up to a maximum of $49 million which Berkshire reached in March 2005. We reserved the cumulative amount of the delayed payments based on Berkshire's inability to generate adequate cash flows related to this agreement. We continue to supply fuel to the plant under the fuel supply agreement and we may incur losses if amounts owed on future fuel deliveries are not paid for under this agreement because of Berkshire's inability to generate adequate cash flow and the uncertainty surrounding their negotiations with their lenders.

Brazil. For contingent matters that could impact our investments in Brazil, see Note 10.

Duke Litigation. Citrus Trading Corporation (CTC), a direct subsidiary of Citrus Corp. (Citrus), in which we own a 50 percent equity interest, has filed suit against Duke Energy LNG Sales, Inc. (Duke) and PanEnergy Corp., the holding company of Duke, seeking damages of $185 million for breach of a gas supply contract and wrongful termination of that contract. Duke sent CTC notice of termination of the gas supply contract alleging failure of CTC to increase the amount of an outstanding letter of credit as collateral for its purchase obligations. CTC filed a motion for partial summary judgment, requesting that the court find that Duke failed to give proper notice of default to CTC regarding its alleged failure to maintain the letter of credit. Duke has filed an amended counter claim in federal court joining Citrus and a cross motion for partial summary judgment, requesting that the court find that Duke had a right to terminate its gas sales contract with CTC due to the failure of CTC to adjust the amount of the letter of credit supporting its purchase obligations. CTC filed an answer to Duke's motion. In August 2005, the federal district court issued an order denying both motions for summary judgment, asserting that the ambiguity in the contract and the performance of the parties created issues of fact that precluded summary judgment for either side. CTC has filed additional motions for partial summary judgment, requesting that the court find that Duke improperly asserted force majeure due to its alleged loss of gas supply and that Duke is in error in asserting that CTC breached contractual provisions that imposed resale restrictions and credit maintenance obligations. An unfavorable outcome on this matter could impact the value of our investment in Citrus. However, we do not expect the ultimate resolution of this matter to have a material adverse effect on us.

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

The information contained in Item 2 updates, and you should read it in conjunction with, information disclosed in our 2004 Annual Report on Form 10-K, as amended, and the financial statements and notes presented in Item 1 of this Quarterly Report on Form 10-Q.

During the second quarter of 2005, we discontinued our south Louisiana gathering and processing operations, which were part of our Field Services segment. Our operating results for the quarter and nine months ended September 30, 2005 reflect these operations as discontinued. Prior period amounts have not been adjusted as these operations were not material to prior period results or historical trends.

Overview

During the third quarter of 2005, we continued to execute our strategic plan while experiencing a number of significant events that impacted our financial results. While we have continued to benefit from escalating commodity prices in our production operations, the rise in natural gas and oil prices during the quarter due, in part, to two major hurricanes during the period, caused us to record substantial non-cash losses on certain derivative transactions and post significant amounts of collateral for margin calls, primarily associated with net derivative liability contracts used to hedge future natural gas and oil production. Additionally, we were unable to fully benefit from escalating commodity prices due to the impact of these hurricanes, which had a significant effect on our offshore production and on other producers in the Gulf of Mexico region, reducing or shutting-in a substantial amount of production in the region. Our pipeline systems also experienced shut-ins from the hurricanes.

By September 30, 2005, these events had resulted in a decline in our available cash and available capacity under our $3 billion credit agreement to approximately $0.9 billion. However, by November 1, our cash and available capacity increased to $2.1 billion due primarily to asset sales, a partial return of collateral for margin calls and the issuance of $400 million of notes by CIG. Additionally, while our pipeline and production businesses did not experience a significant change in revenues or costs as a result of the hurricanes, we anticipate that these businesses will be adversely impacted by the effects of the hurricanes in the fourth quarter of 2005 and into 2006. Our discussion of capital resources and liquidity and individual segment results that follow provide further information on these matters.

Since the beginning of 2005, we have completed the following activities in connection with the ongoing execution of our strategic plan:

- Our Pipeline segment made further progress on its plans by settling a rate case at Southern Natural Gas Company (SNG), recontracting with large customers on the SNG and EPNG systems, and making progress on several pipeline expansion projects in our pipeline systems and at our Elba Island LNG facility;
- Our Production segment continued to make progress on its turnaround and the stabilization of its production rates through its capital drilling program and four strategic acquisitions of natural gas and oil properties, including its recent acquisition of Medicine Bow;
- We continued the exit of our legacy trading business through the assignment or termination of derivative contracts associated with Mohawk River Funding II and Cedar Brakes I and II;
- We completed the sale of a number of assets and investments including, among others, our remaining general and limited partnership interests in Enterprise, interests in Cedar Brakes I and II, the Lakeside Technology Center, our interest in a Korean power facility, our south Louisiana gathering and processing assets, and our interest in the Javelina midstream assets. Total proceeds from these sales were approximately $1.9 billion ($1.2 billion through September 30, 2005);
- We completed a private placement of $750 million of 4.99% convertible perpetual preferred stock, the net proceeds from which were used to prepay our remaining deferred payment obligation on the

Western Energy Settlement for approximately $442 million and to redeem the $300 million of EPTP, 8.25%, Series A cumulative preferred stock; and

• We issued approximately 13.6 million shares of common stock to the holders of our 9.0% equity security units in settlement of their commitment to purchase the shares.

Capital Resources and Liquidity

Our 2004 Annual Report on Form 10-K, as amended, includes a detailed discussion of our liquidity, financing activities, contractual obligations and commercial commitments. The information presented below updates, and you should read it in conjunction with, the information disclosed in that Form 10-K, as amended.

During the nine months ended September 30, 2005, we continued to reduce our overall debt as part of our Long Range Plan announced in December 2003. Our activity during the nine months ended September 30, 2005 was as follows (in millions):

Short-term financing obligations, including current maturities	$ 955
Long-term financing obligations	18,241
Total debt as of December 31, 2004	19,196
Principal amounts borrowed	1,238
Repayments/retirements of principal[1]	(1,964)
Sales of entities[2]	(546)
Total debt as of September 30, 2005	$17,924

(1) Included in retirements is $272 million of notes which were exchanged for equity. This transaction is a non-cash financing transaction.
(2) Related to the sale of Cedar Brakes I and II.

For a further discussion of our long-term debt, other financing obligations and other credit facilities, see Item 1, Financial Statements, Note 9.

Our net available liquidity as of September 30, 2005 was $0.9 billion, which consisted of $0.2 billion of availability under our $3 billion credit agreement and $0.7 billion of available cash. The availability of borrowings under our credit agreement and our ability to incur additional debt is subject to various conditions as further described in Item 1, Financial Statements, Note 9 and our 2004 Annual Report on Form 10-K, as amended, Part II, Item 8, Financial Statements and Supplementary Data, Note 15, which we currently meet. These conditions include compliance with financial covenants and ratios, as defined in the credit agreement, requiring our Debt to Consolidated EBITDA not to exceed 6.25 to 1 and our ratio of Consolidated EBITDA to interest expense and dividends to be equal to or greater than 1.6 to 1, each as defined in our $3 billion credit agreement. As of September 30, 2005, our ratio of Debt to Consolidated EBITDA was 4.94 to 1 and our ratio of Consolidated EBITDA to interest expense and dividends was 2.17 to 1.

In August 2005, our subsidiary, EPPH, entered into a $500 million five-year senior revolving credit facility bearing interest at LIBOR plus 1.875%. Under the facility, we borrowed $500 million which was used to partially fund the acquisition of Medicine Bow. The facility can be utilized for funded borrowings or for the issuance of letters of credit and is collateralized by certain EPPH natural gas and oil production properties. For a discussion of covenants and restrictions under this facility, see Item 1, Financial Statements, Note 9.

In November 2005, we entered into a $400 million revolving borrowing base credit agreement collateralized by production properties owned by one of our subsidiaries, which is also a co-borrower. Under the agreement we have initial borrowing availability of $300 million. The credit facility can be used for revolving credit loans or for the issuance of letters of credit and will mature in May 2006. For a discussion of covenants and restrictions under this agreement, see Item 1, Financial Statements, Note 9.

As part of our Medicine Bow acquisition, we announced our intent to repay amounts borrowed to fund a portion of the acquisition price through the issuance of our common stock. Our current intent is to issue between $500 million and $800 million of our common stock, the timing of which is dependent on market conditions and our ability to access the capital markets. We currently expect that we will make the necessary filings with the SEC in the near future in order to permit us to issue such common stock when market conditions warrant.

A number of factors could influence our liquidity sources, as well as the timing and ultimate outcome of our ongoing efforts and plans as further discussed in our 2004 Annual Report on Form 10-K, as amended. Among these factors are the impact of hurricanes, the impact of future changes in commodity prices on our existing derivative contracts and our ability to complete asset sale and financing transactions during the remainder of 2005. As a result of Hurricanes Katrina and Rita, we incurred significant losses to property, including transmission facilities in our Pipeline segment on TGP, ANR Pipeline Company (ANR) and SNG. To date, we estimate the cost of repairs to be approximately $285 million which we believe is substantially covered through our various insurers. However, we are part of a mutual insurance company that is subject to certain aggregate loss limits by event. If these aggregate event loss limits are met based on the industry-wide damage caused by Hurricanes Katrina and Rita, we may not receive some of these insurance recoveries, which could negatively impact our liquidity or financial results.

We use financial swaps and option contracts which are intended to provide price protection on our anticipated natural gas and oil production. These contracts are at prices significantly below current market prices which have resulted in us posting cash margin deposits with counterparties for the value of these instruments. With the rapid increase in prices during the third quarter of 2005, compounded by the effects of Hurricanes Katrina and Rita, we were required to post an additional $0.7 billion of cash margin deposits with counterparties to these contracts. These amounts will be utilized to settle our derivative contracts if prices remain at current levels. Approximately $0.3 billion of the currently posted cash margin deposits will settle by December 31, 2005 unless prices decrease, at which time margin deposits will be released to us. Any future increases in prices could have a significant impact on our operating cash flows as additional margin deposits would be required. Based on our derivative positions at September 30, 2005, a $0.10 increase in the price of natural gas would result in an increase in our margin requirements by $3 million for transactions that settle by the end of 2005, by $19 million for transactions that settle in 2006, by $6 million for transactions that settle in 2007, by $4 million for transactions that settle in 2008, and by $11 million for transactions that settle in 2009 and thereafter.

We believe we will be able to meet our ongoing liquidity and cash needs through the combination of available cash, cash flow from operations, proceeds from sales of assets, borrowings under our $3 billion credit agreement and borrowing under our new revolving base credit agreement discussed above.

Overview of Cash Flow Activities for 2005 Compared to 2004

For the nine months ended September 30, 2005 and 2004, our cash flows are summarized as follows:

	2005	2004
	(In billions)	
Cash Flow from Operations		
Continuing operating activities		
Net loss before discontinued operations	$(0.4)	$(0.3)
Non-cash income adjustments	1.2	1.3
Change in broker margin deposits	(0.7)	0.1
Change in assets and liabilities	(0.5)	(0.5)
Total cash flow from operations	$(0.4)	$ 0.6
Other Cash Inflows		
Continuing investing activities		
Net proceeds from the sale of assets and investments	$ 1.1	$ 1.7
Proceeds from settlement of a foreign currency derivative	0.1	—
Reduction of restricted cash	0.1	0.5
Other	0.2	0.1
	1.5	2.3

	2005	2004
	(In billions)	
Continuing financing activities		
Net proceeds from the issuance of long-term debt	1.2	0.1
Proceeds from the issuance of preferred stock	0.7	—
Contributions from discontinued operations	0.1	1.0
	2.0	1.1
Total other cash inflows	$ 3.5	$ 3.4
Other Cash Outflows		
Continuing investing activities		
Capital expenditures	$ 1.3	$ 1.3
Net cash paid for acquisitions	1.0	—
	2.3	1.3
Continuing financing activities		
Payments to retire debt and redeem preferred interests	1.6	1.7
Redemption of preferred stock of a subsidiary	0.3	—
Dividends paid	0.1	0.1
	2.0	1.8
Total other cash outflows	$ 4.3	$ 3.1
Net change in cash	$(1.2)	$ 0.9

Cash From Continuing Operating Activities

Overall, cash flow from our continuing operating activities for the first nine months of 2005 was $1.0 billion lower than the same period of 2004, primarily as a result of $0.8 billion of higher margin calls on marketing and trading activities in 2005.

Additionally in 2005, we experienced additional uses of working capital including a $0.2 billion payment to assign or terminate derivative contracts in connection with the sale of Cedar Brakes I and II, $0.4 billion of hedging derivative settlements, and $0.4 billion for the prepayment of the Western Energy Settlement, which were partially offset by a $0.5 billion increase in other working capital. In the first nine months of 2004, we experienced a $0.4 billion use of working capital primarily due to a payment to settle the principal litigation under the Western Energy Settlement.

Cash From Continuing Investing Activities

Net cash used in our continuing investing activities was $0.8 billion for the nine months ended September 30, 2005. Our investing activities consisted of the following (in billions):

Production exploration, development and acquisition expenditures	$(1.7)
Pipeline expansion, maintenance and integrity projects	(0.6)
Decrease in restricted cash	0.1
Settlement of a foreign currency derivative	0.1
Proceeds from sales of assets and investments	1.1
Other	0.2
Total continuing investing activities	$(0.8)

Cash received from sales of assets and investments was primarily from the sale of our remaining interests in Enterprise, certain international and domestic power assets, and the sale of the Lakeside Technology Center. The settlement of a foreign currency derivative relates to cash received on a derivative entered into to hedge currency and interest rate risk on a portion of our Euro denominated debt. This derivative was settled upon the retirement of that debt. In August 2005, we acquired Medicine Bow for $0.8 billion. The acquisition was funded by existing cash on hand and a new $500 million, five-year revolving credit facility which is collateralized by a portion of EPPH's natural gas and oil reserves. We intend to repay this facility within one year from closing through an issuance of El Paso common equity. We also expect additional capital expenditures of $0.2 billion in our Production segment and $0.4 billion in our Pipelines segment during the remainder of 2005.

During the fourth quarter of 2005, we received $156 million in sales proceeds from the sale of our interests in the Javelina natural gas processing and pipeline assets. In addition, in our discontinued operations, we received sales proceeds of approximately $486 million from the sale of our south Louisiana gathering and processing assets. During 2005, we also announced the sales of our interest in a power facility in Hungary and substantially all of our other Asian power assets. We expect to receive total proceeds of approximately $284 million for these assets.

Cash From Continuing Financing Activities

Our cash inflows from continuing financing activities were equal to our cash outflows for the nine months ended September 30, 2005. We generated cash of $2.0 billion primarily from the issuance of $0.7 billion of convertible preferred stock, and $1.2 billion of long-term debt including our subsidiaries CIG, Cheyenne Plains and EPPH. However, we made repayments of $0.9 billion to retire third party long-term debt, paid $0.7 billion to retire a portion of our Euro-denominated debt and redeemed $0.3 billion of cumulative preferred stock of EPTP, our subsidiary. In addition, we made $0.1 billion of dividend payments during the period.

Commodity-based Derivative Contracts

We use derivative financial instruments in our hedging activities, power contract restructuring activities and in our historical energy trading activities. The following table details the fair value of our commodity-based derivative contracts by year of maturity as of September 30, 2005:

Source of Fair Value	Maturity Less Than 1 year	Maturity 1 to 3 Years	Maturity 4 to 5 Years	Maturity 6 to 10 Years	Maturity Beyond 10 Years	Total Fair Value
			(In millions)			
Derivatives designated as hedges						
Assets	$ 36	$ 8	$ —	$ —	$ —	$ 44
Liabilities	(846)	(196)	(30)	(18)	—	(1,090)
Total derivatives designated as hedges	(810)	(188)	(30)	(18)	—	(1,046)
Assets from power contract restructuring derivatives[1]	21	35	—	—	—	56
Other commodity-based derivatives						
Exchange-traded positions[2]						
Assets	290	306	136	8	—	740
Liabilities	(422)	(15)	—	—	—	(437)
Non-exchange-traded positions						
Assets	763	566	235	155	23	1,742
Liabilities[1]	(826)	(900)	(374)	(187)	(39)	(2,326)
Total other commodity-based derivatives	(195)	(43)	(3)	(24)	(16)	(281)
Total commodity-based derivatives	$(984)	$(196)	$ (33)	$ (42)	$(16)	$(1,271)

(1) In October 2005, we sold our interest in Mohawk River Funding II, a wholly-owned subsidiary which held our only remaining restructured power contract. In connection with this sale, we also assigned to a third party other commodity-based derivatives that had a fair value of $9 million as of September 30, 2005, and terminated $18 million of intercompany derivatives that eliminate in consolidation.

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

Below is a reconciliation of our commodity-based derivatives for the period from January 1, 2005 to September 30, 2005:

	Derivatives Designated as Hedges	Derivatives from Power Contract Restructuring Activities	Other Commodity-Based Derivatives	Total Commodity-Based Derivatives
	(In millions)			
Fair value of contracts outstanding at January 1, 2005	$ (536)	$ 665	$ (61)	$ 68
Fair value of contract settlements during the period	367	(620)	332	79
Change in fair value of contracts	(888)	11	(568)	(1,445)
Reclassification of derivatives that no longer qualify as hedges[1]	11	—	(11)	—
Option premiums paid, net	—	—	27	27
Net change in contracts outstanding during the period	(510)	(609)	(220)	(1,339)
Fair value of contracts outstanding at September 30, 2005	$(1,046)	$ 56	$(281)	$(1,271)

(1) We have a derivative that hedges the production owned by UnoPaso, a wholly-owned subsidiary that owns natural gas and oil properties in Brazil. As a result of the earlier than expected payout to us of certain of UnoPaso's natural gas and oil properties, which will reduce our interest in the properties and related production volumes, we reclassified an $11 million liability associated with a hedge of this production to other commodity-based derivatives.

The fair value of contract settlements during the period represents the estimated amounts of derivative contracts settled through physical delivery of a commodity or by a claim to cash as accounts receivable or payable. The fair value of contract settlements also includes physical or financial contract terminations due to counterparty bankruptcies and the sale or settlement of derivative contracts through early termination or through the sale of the entities that own these contracts.

In March 2005, we sold our Cedar Brakes I and II subsidiaries and their related restructured power contracts, which had a fair value of $596 million as of December 31, 2004. In connection with the sale, we also assigned or terminated other commodity-based derivatives that had a fair value liability of $240 million as of December 31, 2004.

The change in fair value of contracts during the period represents the change in value of contracts from the beginning of the period, or the date of their origination or acquisition, until their settlement or, if not settled, until the end of the period.

Segment Results

Below are our results of operations (as measured by EBIT) by segment. Our regulated business consists of our Pipelines segment, while our unregulated businesses consist of our Production, Marketing and Trading, Power and Field Services segments. Our segments are strategic business units that provide a variety of energy products and services. They are managed separately as each segment requires different technology and marketing strategies. Our corporate activities include our general and administrative functions, as well as a telecommunications business and various other contracts and assets. During the second quarter of 2005, we discontinued our south Louisiana gathering and processing operations, which were part of our Field Services segment. Our operating results for the quarter and nine months ended September 30, 2005 reflect these operations as discontinued. Prior period amounts have not been adjusted as these operations were not material to prior period results or historical trends.

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

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2005	2004	2005	2004
	(In millions)			
Regulated Business				
Pipelines	$ 272	$ 268	$ 993	$ 962
Non-regulated Businesses				
Production	169	150	528	558
Marketing and Trading	(398)	(138)	(613)	(454)
Power	(41)	(7)	(472)	(74)
Field Services	(22)	61	157	124
Segment EBIT	(20)	334	593	1,116
Corporate	(67)	(57)	(169)	(21)
Consolidated EBIT from continuing operations	(87)	277	424	1,095
Interest and debt expense	(344)	(396)	(1,034)	(1,229)
Distributions on preferred interests of consolidated subsidiaries	—	(6)	(9)	(18)
Income taxes	108	(77)	165	(135)
Loss from continuing operations	(323)	(202)	(454)	(287)
Discontinued operations, net of income taxes	11	(12)	10	(118)
Net loss	$(312)	$(214)	$ (444)	$ (405)

Overview of Segment Results

For the nine months ended September 30, 2005, our segment EBIT was $593 million. During the nine month period, our Pipelines, Production and Field Services segments contributed $1,678 million of combined EBIT. These positive contributions were partially offset by the EBIT losses of $613 million in our Marketing and Trading segment and $472 million in our Power segment. The following overview summarizes the results of operations by operating segment compared to our internal expectations for the period.

Pipelines — Our Pipelines segment generated EBIT of $993 million, which was slightly above our expectations for the period.

Production — Our Production segment generated EBIT of $528 million, which was slightly above our expectations for the period. Higher than expected commodity prices more than offset lower than expected production volumes and higher depletion and production costs.

Marketing and Trading — Our Marketing and Trading segment generated an EBIT loss of $613 million, which was a greater loss than our expectations. The performance was primarily a result of significant mark-to-market losses on our production-related derivatives due to substantial natural gas price increases during the period.

Power	Our Power segment generated an EBIT loss of $472 million, which was a greater loss than expected, and was impacted by significant impairments of our Macae project in Brazil and our Asian and Central American power assets and losses from our investment in Midland Cogeneration Venture resulting from a significant impairment at the underlying power plant.
Field Services	Our Field Services segment generated EBIT of $157 million, which was consistent with our expectations and was primarily due to the gain on the sale of our remaining interests in Enterprise.

For the remainder of 2005, we expect the trends discussed above to continue in our Production segment, given the current favorable pricing environment for natural gas and oil and the reductions in our offshore production levels as a result of Hurricanes Katrina and Rita. In our Pipelines segment, we expect to finish the year slightly below our expectations, primarily because of the impacts of the hurricanes on the efficiency of our pipeline systems. We also anticipate our Marketing and Trading segment's EBIT will continue to be volatile due to changes in natural gas and power prices as they relate to our trading portfolio. In our Power segment, we may generate EBIT losses as we continue to sell or pursue the sale of our Asian and Central American power plant portfolio and continue negotiations with Petrobras relating to our Macae power investment. Finally, we expect our EBIT to increase in our Field Services segment as a result of a gain on the sale of our interest in the Javelina natural gas processing and pipeline assets. Below is a discussion of our individual segment results.

Regulated Business — Pipelines Segment

Operating Results

Below are the operating results and analysis of these results for our Pipelines segment for the periods ended September 30:

Pipelines Segment Results	Quarter Ended September 30, 2005	Quarter Ended September 30, 2004	Nine Months Ended September 30, 2005	Nine Months Ended September 30, 2004
	(In millions except volume amounts)			
Operating revenues	$ 646	$ 604	$ 2,067	$ 1,942
Operating expenses	(439)	(386)	(1,236)	(1,116)
Operating income	207	218	831	826
Other income	65	50	162	136
EBIT	$ 272	$ 268	$ 993	$ 962
Throughput volumes (BBtu/d)	20,900	19,480	21,260	20,637

The following contributed to our overall EBIT increase for the quarter and nine months ended September 30, 2005 as compared to the same period in 2004:

	Quarter Ended September 30,				Nine Months Ended September 30,			
	Revenue	Expense	Other	EBIT	Revenue	Expense	Other	EBIT
	Favorable/(Unfavorable) (In millions)				Favorable/(Unfavorable) (In millions)			
Pipeline expansions	$19	$ (7)	$(1)	$ 11	$ 57	$ (22)	$ 1	$ 36
Contract modifications/terminations/ settlements	—	—	—	—	48	—	1	49
Gas not used in operations, revaluations, processing revenues and other natural gas sales	16	(24)	—	(8)	35	(20)	—	15
Favorable resolution in 2004 of measurement dispute at a processing plant	—	—	—	—	(10)	—	—	(10)
Higher allocated costs	—	(10)	—	(10)	—	(56)	—	(56)
Higher operating costs	—	(7)	—	(7)	—	(20)	—	(20)
Equity earnings from our investment in Citrus	—	—	1	1	—	—	6	6
Sale of interest in Ft. Union gathering system	—	—	11	11	—	—	11	11
Other[(1)]	7	(5)	4	6	(5)	(2)	7	—
Total impact on EBIT	$42	$(53)	$15	$ 4	$125	$(120)	$26	$ 31

(1) Consists of individually insignificant items across several of our pipeline systems.

The following provides further discussion on the items listed above as well as an outlook on events that may affect our operations in the future.

Expansions

In January 2005, the Cheyenne Plains Gas Pipeline was placed in-service. As a result, our revenues increased by $44 million and overall EBIT increased by $21 million during the first nine months of 2005 compared to the same period in 2004. Phase II of the Cheyenne Plains Pipeline, which will add 176,000 Mcf/d of capacity, is expected to be in service in December 2005.

In addition, we have the following projects that have been approved by FERC, and that are in various stages of completion.

In April 2003, the FERC approved the expansion of the Elba Island LNG facility to increase the base load sendout rate of the facility from 446 MMcf/d to 806 MMcf/d. Our current cost estimates for the expansion are approximately $157 million and as of September 30, 2005, our expenditures were approximately $132 million. We expect to place the expansion in service in February 2006. As a result of increasing capital invested in the expansion, higher AFUDC was capitalized in 2005 resulting in higher EBIT compared to 2004. This expansion is estimated to increase our revenues by $29 million annually.

In September 2005, the FERC approved Wyoming Interstate Company Ltd.'s Piceance Basin Expansion Project, which will consist of the construction and operation of approximately 142 miles of 24-inch pipeline, compression, and metering facilities. Estimated costs of the project are approximately $120 million and construction is expected to start in November 2005, with an estimated in service date of the first quarter 2006, assuming favorable weather conditions. This expansion is estimated to increase our revenues by $11 million in 2006, $19 million in 2007 and $21 million annually thereafter.

In June 2005, the FERC authorized CIG to construct the Raton Basin expansion, which will add 104 MMcf/d of capacity to its system. The project is fully subscribed for 10 years, and 14 percent of the capacity will be held by an affiliate. Estimated costs of the project are approximately $59 million. Construction began in June and portions of the project went into service in September 2005 with the remaining facilities expected to be in service in November and December 2005. This expansion is estimated to increase revenues by $9 million in 2006 and $13 million annually thereafter.

In order to meet increased demand in EPNG's markets and comply with FERC orders, EPNG completed Phases I, II and III of its Line 2000 Power-up project, which increased the capacity of that line by 320 MMcf/d. In June 2005, EPNG received FERC approval for its Cadiz to Ehrenberg project that will increase its north-to-south capacity by 372 MMcf/d. Construction began in September 2005 and the project is scheduled to be in service by late 2005. EPNG expects to earn revenues associated with these expansions beginning in January 2006.

Contract Modifications/Terminations/Settlements

Included in this item are (i) the impact of ANR restructuring its transportation contracts with one of its shippers on its Southwest and Southeast Legs as well as a related gathering contract in March 2005, which increased revenues and EBIT by $29 million in the first quarter of 2005 (ii) the impact of ANR settling two transportation agreements previously rejected in the bankruptcy of USGen New England, Inc., which increased EBIT by $15 million and (iii) the impact of the termination, of EPNG's restrictions on remarketing expiring capacity contracts resulting in increased revenues and EBIT of $5 million during the first nine months of 2005 as compared to 2004. ANR's settlement with USGen will not have an ongoing impact on our Pipelines segment results.

Southern California Gas Company (SoCal) successfully acquired approximately 750 MMcf/d of capacity on EPNG's system under new contracts with various terms extending from 2009 to 2011 commencing September 2006. We have executed the relevant transportation service agreements with SoCal. Effective September 2006, approximately 500 MMcf/d of capacity formerly held by SoCal to serve its non-core customers will be available for recontracting. We are remarketing the remaining expiring capacity to serve SoCal's non-core customers or to serve new markets. We are also pursuing the option of using some or all of this capacity to provide new services to existing markets. At this time, we are uncertain how much of this existing capacity will be recontracted, and if so at what rates.

Gas Not Used in Operations, Revaluations, Processing Revenues and Other Natural Gas Sales

For some of our regulated pipelines, the financial impact of operational gas, net of gas used in operations is based on the amount of natural gas we are allowed to retain and dispose of according to our tariffs or FERC orders, relative to the amount of gas we use for operating purposes, and the price of natural gas. Gas retained and not needed for operations results in revenues to us, which are driven by volumes and prices during a given period. In addition, the timing of these revenues can vary based on each pipeline's ability to sell or otherwise realize the value of gas not used in operations. The level of retained gas on our systems relative to amounts we use are based on factors such as system throughput, facility enhancements and the ability to operate the pipeline in the most efficient and safe manner. Additionally, several of our pipelines have encroachments against their system gas supply and net imbalances to shippers that are impacted by changing gas prices each period. In 2005, the sale of higher volumes of natural gas made available by storage realignment projects and higher volumes of gas not utilized in operations resulted in a favorable impact on our operating results versus 2004. This favorable impact was offset because higher gas prices in the third quarter of 2005 caused an increase in our obligation to replace system gas and settle gas imbalances in the future. We anticipate that the overall activity in this area will continue to vary based on factors such as rate actions, some of which have already been implemented, the efficiency of our pipeline operations, natural gas prices and other factors. For a further discussion of this area of our business, refer to our 2004 Annual Report on Form 10-K, as amended.

Allocated Costs

El Paso allocates general and administrative costs to each business segment. The allocation is based on the estimated level of effort devoted to each segment's operations and the relative size of its EBIT, gross property and payroll as compared to our consolidated totals. During the quarter and nine months ended September 30, 2005, the Pipelines segment was allocated higher costs than the same periods in 2004, primarily due to an increase in benefits accrued under our retirement plan and higher legal, insurance and professional fees. In addition, we were allocated a larger percentage of El Paso's total corporate costs due to the relationship of the segments' asset base and earnings to El Paso's overall asset base and earnings.

Higher Operating Costs

During 2005, we experienced higher operating costs for compressor engine repair and preventative maintenance, lowering of lines and pipeline integrity testing.

Regulatory and Other Matters

Our pipeline systems periodically file for changes in their rates which are subject to the approval of the FERC. Changes in rates and other tariff provisions resulting from these regulatory proceedings can significantly impact our profitability.

EPNG Rate Case. In June 2005, EPNG filed a rate case with the FERC proposing an increase in revenues of 10.6 percent or $56 million over current tariff rates, subject to refund, and also proposing new services and revisions to certain terms and conditions of existing services, including the adoption of a fuel tracking mechanism. The rate case would be effective January 1, 2006. In addition, the reduced tariff rates provided to EPNG's former full requirements customers under the terms of its FERC approved systemwide capacity allocation proceeding will expire. The combined effect of the proposed increase in tariff rates and the expiration of the lower rates is estimated to increase our revenues by approximately $138 million. In July 2005, the FERC accepted certain of the proposed tariff revisions, including the adoption of the fuel tracking mechanism. See Item 1, Financial Statements, Note 10, for a further discussion of this matter. The outcome of this rate case cannot be predicted with certainty at this time.

As part of EPNG's rate case, it sought recovery, through a tracking mechanism, of costs associated with renewing its right-of-way on Navajo Nation lands, which is discussed in Item 1, Financial Statements, Note 10. The FERC initially rejected EPNG's request, but invited EPNG to seek a waiver of its regulations to permit the cost of the right-of-way to be included in its pending rate case if the final cost becomes known and measurable within a reasonable time after the close of the test period on December 31, 2005. The timing and/or extent of recovery could impact future financial results.

For a further discussion of our recent and upcoming rate proceedings, refer to our 2004 Annual Report on Form 10-K, as amended.

Accounting for Pipeline Integrity Costs. In June 2005, the FERC issued an accounting release that will impact certain costs our interstate pipelines incur related to their pipeline integrity programs. This release will require us to expense certain pipeline integrity costs incurred after January 1, 2006 instead of capitalizing them as part of our property, plant and equipment. EPNG filed a request with the FERC to allow EPNG to early adopt the provisions of this release in December 2005. Although we continue to evaluate the impact that this accounting release will have on our consolidated financial statements, we currently estimate that we will be required to expense an additional amount of pipeline integrity costs under the release in the range of approximately $23 million to $39 million annually.

Other. Hurricanes Katrina and Rita had substantial impacts on offshore producers in the Gulf of Mexico Region resulting in the shut-in of a significant portion of offshore production in the affected areas. Hurricane Katrina resulted in the initial shut-in of approximately 3 Bcf/d on our pipeline systems. Prior to Hurricane Rita, our pipelines had approximately 1.2 Bcf/d of natural gas supply shut-in. Hurricane Rita resulted in an incremental reduction in supply of approximately 2.9 Bcf/d on our systems. Currently, we have approximately 2.1 Bcf/d of natural gas shut-in on our pipeline systems. The timing of these volumes becoming available is dependent on the completion of pipeline and compressor station repairs, the ongoing evaluation of producers' platforms upstream of our pipelines, and potential processing constraints if third-party processing facilities are not available. Furthermore, these operational constraints have impacted the efficiency of our pipeline operations, particularly in the area of gas not used in operations on our TGP system. Through September 2005, we did not experience a significant decrease in EBIT as a result of these hurricanes.

However, we anticipate the hurricanes will adversely affect our EBIT in the fourth quarter of 2005, the impact of which is currently estimated to be in the range of $20 million to $40 million, because of the impact on gas not used in operations, certain usage revenues, potential unreimbursed repair costs, increased operating costs and potential lost revenues associated with reductions in service. These adverse effects may continue into early 2006.

Non-regulated Business — Production Segment

Overview

Our Production segment conducts our natural gas and oil exploration and production activities. Our operating results in this segment are driven by a variety of factors including the ability to locate and develop economic natural gas and oil reserves, extract those reserves with minimal production costs, sell the products at attractive prices, and to minimize our total administrative costs. We continue to manage our business with a goal to stabilize production by improving the production mix across our operating areas through a more balanced allocation of our capital to development and exploration projects, and through acquisition activities with low risk development opportunities that provide operating synergies with our existing operations.

Significant Operational Factors Since December 31, 2004

Since December 31, 2004, we have experienced the following:

- *Higher realized prices.* During the first nine months of 2005, we continued to benefit from a strong commodity pricing environment. Realized natural gas prices, which include the impact of our hedges, increased 11 percent while oil, condensate and NGL prices increased 35 percent compared to 2004.

- *Average daily production of 770 MMcfe/d (including 8 MMcfe/d from our unconsolidated affiliate).* Our average daily production in the third quarter of 2005 decreased from the second quarter of 2005 due primarily to several hurricanes in the Gulf of Mexico during the quarter which caused us to shut in significant volumes in our offshore region. In the third quarter of 2005, our average daily production volumes were impacted by the loss of approximately 39 MMcfe/d as a result of hurricanes. We have continued to increase production volumes in our onshore region as a result of our drilling programs and the impact of the acquisitions discussed below. However, production volumes in our offshore and Texas Gulf Coast regions continued to decrease gradually as drilling programs and overall lower capital spending in those areas have not been sufficient to offset the historically steep production decline rates in these regions. During 2005, our production volumes in Brazil have remained steady, averaging 53 MMcfe/d, but we expect these volumes to decrease by about 30 MMcfe/d in 2006 due to a decrease in our interest in Brazilian production as further described in Production Hedge Position below.

- *Impact of hurricanes on production volumes.* Prior to Hurricane Katrina in late August 2005, our production from the Gulf of Mexico was about 205 MMcfe/d. A substantial portion of our shut-in production from Hurricane Katrina was brought back online during September 2005 to a level of about 170 MMcfe/d just prior to Hurricane Rita. We continue to experience substantial shut-in volumes from Hurricane Rita; however Gulf of Mexico production levels have returned to approximately 90 MMcfe/d at November 1, 2005 and we expect that it will approach 135 MMcfe/d by December 1, 2005. The majority of the remaining Gulf of Mexico production is expected to come back online during the first quarter of 2006. Also impacted were our onshore Texas Gulf Coast and Arklatex areas, where damage from Hurricane Rita initially impacted approximately 60 MMcfe/d. Repairs to these facilities have been completed, and this production is back on stream.

- *Acquisitions and other capital expenditures.* During the first nine months of 2005, our capital expenditures totaled $1.7 billion including the acquisition of Medicine Bow (as further discussed in Item 1, Financial Statements, Note 2), acquisitions in east and south Texas and the purchase of the interest held by one of our partners under a net profits interest agreement. These acquisitions added properties with approximately 523 Bcfe of proved reserves, including reserves owned by an unconsolidated affiliate of Medicine Bow. The Texas acquisitions offer additional exploration upside in two of our key operating areas, while the Medicine Bow acquisition increases our presence in the Rocky Mountains, complements our existing core operations, diversifies our commodity mix and increases our reserve life.

- *Drilling Results.* In 2005, we announced deep shelf discoveries at West Cameron Block 75 and West Cameron Block 62 in the Gulf of Mexico. At West Cameron Block 75, we have a 36 percent working interest and an approximate 30 percent net revenue interest. We have tested the discovery and anticipate deliverability of approximately 40 MMcfe/d. At West Cameron Block 62, we have a 54 percent working interest and an approximate 45 percent net revenue interest. We have tested the well at rates up to 15 MMcfe/d. We expect both discoveries to come on line during the first quarter of 2006, after the installation of facilities.

Outlook for the last three months of 2005

For 2005, we anticipate the following:

- Daily production volumes for the year to average approximately 760 MMcfe/d, including approximately 24 MMcfe/d from our interest in an unconsolidated affiliate of Medicine Bow;
- Cash operating costs to average approximately $1.65/Mcfe for the year;
- Industry-wide increases in drilling and oilfield service costs that will require constant monitoring of capital spending programs;
- Domestic unit of production depletion rate of $2.16/Mcfe in the fourth quarter of 2005 as compared to $2.11/Mcfe in the third quarter of 2005, due to higher finding and development costs and the costs of acquired reserves; and
- Brazilian unit of production depletion rate of $2.39/Mcfe in the fourth quarter of 2005 as compared to $2.34/Mcfe in the third quarter of 2005 due to factors described in Production Hedge Position below.
- Capital expenditures of approximately $0.2 billion for the last three months of 2005.

Production Hedge Position

As part of our overall strategy, we hedge our natural gas and oil production to stabilize cash flows, reduce the risk of downward commodity price movements on our sales and to protect the economic assumptions associated with our capital investment programs. Our Marketing and Trading segment has also entered into other derivative contracts that are designed to provide price protection to the overall company, which are discussed further in that segment's operating results. Our hedging activities are further discussed in our 2004 Annual Report on Form 10-K, as amended.

Overall, we experienced a significant decrease in the fair value of our hedging derivatives discussed above in the first nine months of 2005. These non-cash fair value decreases are generally deferred in our accumulated other comprehensive income and will be realized in our operating results at the time the production volumes to which they relate are sold. As of September 30, 2005, the fair value of these positions that is deferred in accumulated other comprehensive income is a pretax loss of $796 million. The income impact of the settlement of these derivative commodity instruments will be substantially offset by the impact of the corresponding change in the price to be received when the hedged natural gas production is sold.

We acquired an additional interest in UnoPaso in Brazil in 2004. In accordance with our agreement, our ownership interest in certain of UnoPaso's natural gas and oil properties will decrease from 79 percent to 35 percent upon attaining payout. Due to continued higher than expected oil prices and positive well performance from these properties, we expect this payout to occur by the end of 2005, which is earlier than we had previously forecasted. At the time we acquired our interest, we also entered into a hedge on a portion of our forecasted oil production through December 2007. With the earlier than anticipated reduction in production volumes beginning in 2006, we were required to mark-to-market the related hedge positions in our income statement. production volumes beginning in 2006, we were required to mark-to-market the related hedge positions in our income statement and recorded a loss of $11 million in other operating revenues during the third quarter of 2005. This loss was previously reflected in accumulated other comprehensive income.

Operating Results

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

Production Segment Results	Quarter Ended September 30, 2005	Quarter Ended September 30, 2004	Nine Months Ended September 30, 2005	Nine Months Ended September 30, 2004
	(In millions, except volumes and prices)			
Operating Revenues:				
Natural gas	$ 354	$ 325	$ 1,061	$ 1,056
Oil, condensate and NGL	105	75	286	218
Other	(10)	—	(7)	2
Total operating revenues	449	400	1,340	1,276
Transportation and net product costs[1]	(11)	(13)	(36)	(40)
Total operating margin	438	387	1,304	1,236
Operating Expenses:				
Depreciation, depletion and amortization	(153)	(136)	(456)	(407)
Production costs[2]	(72)	(58)	(186)	(144)
Restructuring charges	—	(1)	(2)	(12)
General and administrative expenses	(45)	(47)	(129)	(120)
Taxes other than production and income	(1)	2	(9)	(1)
Total operating expenses[1]	(271)	(240)	(782)	(684)
Operating income	167	147	522	552
Other income	2	3	6	6
EBIT	$ 169	$ 150	$ 528	$ 558

	Quarter Ended September 30,			Nine Months Ended September 30,		
	2005	2004	Percent Variance	2005	2004	Percent Variance
Consolidated volumes, prices and costs:						
Natural gas						
Volumes (MMcf)	55,280	59,282	(7)%	169,228	186,516	(9)%
Average realized prices including hedges ($/Mcf)[3][4]	$ 6.40	$ 5.48	17%	$ 6.27	$ 5.66	11%
Average realized prices excluding hedges ($/Mcf)[3]	$ 7.74	$ 5.53	40%	$ 6.59	$ 5.73	15%
Average transportation costs ($/Mcf)	$ 0.18	$ 0.18	—	$ 0.18	$ 0.16	13%
Oil, condensate and NGL						
Volumes (MBbls)	2,068	2,013	3%	6,464	6,660	(3)%
Average realized prices including hedges ($/Bbl)[3]	$ 50.77	$ 37.32	36%	$ 44.23	$ 32.81	35%
Average realized prices excluding hedges ($/Bbl)[3]	$ 51.88	$ 37.44	39%	$ 44.94	$ 32.85	37%
Average transportation costs ($/Bbl)	$ 0.60	$ 1.00	(40)%	$ 0.64	$ 1.24	(48)%
Total equivalent volumes (MMcfe)	67,684	71,359	(5)%	208,011	226,474	(8)%
Production costs ($/Mcfe)						
Average lease operating cost	$ 0.74	$ 0.67	10%	$ 0.71	$ 0.55	29%
Average production taxes	0.32	0.14	129%	0.19	0.09	111%
Total production cost[2]	$ 1.06	$ 0.81	31%	$ 0.90	$ 0.64	41%
Average general and administrative cost ($/Mcfe)	$ 0.65	$ 0.65	—	$ 0.62	$ 0.53	17%
Unit of production depletion cost ($/Mcfe)	$ 2.11	$ 1.75	21%	$ 2.05	$ 1.66	23%
Unconsolidated affiliate volumes (Four Star)[5]						
Natural Gas (MMcf)	1,605			1,605		
Oil, condensate and NGL (MBbls)	92			92		
Total equivalent volumes (MMcfe)	2,156			2,156		

(1) Transportation and net product costs are included in operating expenses on our consolidated statement of income.

(2) Production costs include lease operating costs and production related taxes (including ad valorem and severance taxes).

(3) Prices are stated before transportation costs.

(4) The average realized prices for natural gas, including hedges listed above, reflect the amounts recorded by the Production segment for sales of natural gas volumes. On a consolidated basis, El Paso receives a lower cash price on a portion of the volumes sold as further discussed in our 2004 Annual Report on Form 10-K, as amended.

(5) Represents our proportionate share of Four Star's volumes. Our equity interest in Four Star was acquired in connection with our acquisition of Medicine Bow in August 2005.

Quarter and Nine months Ended September 30, 2005 Compared to Quarter and Nine Months Ended September 30, 2004

The table below lists the significant variances in our operating results in the quarter and nine months ended September 30, 2005, as compared to the same periods in 2004:

	Variance			
Quarter Ended September 30,	**Operating Revenue**	**Operating Expense**	**Other[1]**	**EBIT Impact**
		Favorable/(Unfavorable) (In millions)		
Natural Gas Revenue				
Higher realized prices in 2005	$122	$ —	$ —	$122
Lower volumes in 2005	(22)	—	—	(22)
Impact from hedge program in 2005 versus 2004	(71)	—	—	(71)
Oil, Condensate, and NGL Revenue				
Higher realized prices in 2005	30	—	—	30
Higher volumes in 2005	2	—	—	2
Impact from hedge program in 2005 versus 2004	(2)	—	—	(2)
Depreciation, Depletion, and Amortization Expense				
Higher depletion rate in 2005	—	(24)	—	(24)
Lower production volumes in 2005	—	6	—	6
Production Costs				
Higher lease operating costs in 2005	—	(2)	—	(2)
Higher production taxes in 2005	—	(12)	—	(12)
Other				
Lower general and administrative costs in 2005	—	2	—	2
Other	(10)	(1)	1	(10)
Total Variances	$ 49	$(31)	$ 1	$ 19

	Variance			
Nine Months Ended September 30,	**Operating Revenue**	**Operating Expense**	**Other[1]**	**EBIT Impact**
		Favorable/(Unfavorable) (In millions)		
Natural Gas Revenue				
Higher realized prices in 2005	$146	$ —	$—	$146
Lower volumes in 2005	(99)	—	—	(99)
Impact from hedge program in 2005 versus 2004	(42)	—	—	(42)
Oil, Condensate, and NGL Revenue				
Higher realized prices in 2005	78	—	—	78
Lower volumes in 2005	(6)	—	—	(6)
Impact from hedge program in 2005 versus 2004	(4)	—	—	(4)
Depreciation, Depletion, and Amortization Expense				
Higher depletion rate in 2005	—	(81)	—	(81)
Lower production volumes in 2005	—	31	—	31
Production Costs				
Higher lease operating costs in 2005	—	(21)	—	(21)
Higher production taxes in 2005	—	(21)	—	(21)
Other				
Higher general and administrative costs in 2005	—	(9)	—	(9)
Other	(9)	3	4	(2)
Total Variances	$ 64	$(98)	$ 4	$(30)

(1) Consists primarily of charges in transportation costs and other income.

Operating Revenues. During 2005, we continued to benefit from a strong commodity pricing environment for natural gas and oil, condensate and NGL. However, our hedging program losses for the quarter and nine months ended September 30, 2005 were $76 million and $59 million, compared to $3 million and $13 million for the same periods in 2004. Additionally, we experienced a significant decrease in production volumes versus the same periods in 2004. Although our production volumes have benefited from the acquisitions in 2005 discussed earlier and our acquisition and consolidation of the remaining interest in UnoPaso in Brazil in July 2004, our offshore and Texas Gulf Coast regions experienced declines in year over year production due to normal declines and a lower capital spending program over the last several years. In addition, the offshore region was impacted by the hurricanes discussed previously, while the Texas Gulf Coast region was impacted by mechanical well failures.

Depreciation, depletion, and amortization expense. During 2005, we experienced higher depletion rates compared with 2004 as a result of higher finding and development costs and the cost of acquired reserves which resulted in higher depreciation, depletion, and amortization expense. However, during 2005, lower depletion expense resulting from the lower production volumes discussed above partially offset the impact of our higher depletion rates.

Production costs. We continue to experience higher costs in 2005 due to the implementation of programs in the first and second quarters of 2005 to improve production in the offshore Gulf of Mexico and Texas Gulf Coast regions, higher salt water disposal and utility expenses and increased operating costs in Brazil due to our July 2004 UnoPaso acquisition. Also, our production taxes continue to be higher as the result of higher commodity prices in 2005, and higher tax credits taken in 2004 on high cost natural gas wells. The cost per unit increased primarily due to the lower production volumes and higher production costs mentioned above.

Other. In addition to our general and administrative costs, El Paso allocates general and administrative costs to each business segment. The allocation is based on the estimated level of effort devoted to each segment's operations and the relative size of its EBIT, gross property and payroll as compared to the consolidated totals. During the quarter and nine months ended September 30, 2005, we were allocated higher costs than the same periods in 2004, primarily due to an increase in benefits accrued under retirement plans and higher legal, insurance and professional fees. In addition, we were allocated a larger percentage of El Paso's total corporate costs due to the significance of our asset base and earnings to El Paso's overall asset base and earnings. The cost per unit of general and administrative expenses increased due to a combination of higher costs and lower production volumes discussed above. The decrease in other operating expenses for the nine months related to employee severance expenses of $2 million in 2005 compared with $11 million in 2004. The decrease in other revenues for the quarter and the months ended September 30, 2005 was due primarily to an $11 million loss related to the elimination of hedge accounting on a derivative contract on our Brazilian production.

Non-regulated Business — Marketing and Trading Segment

Our Marketing and Trading segment's operations focus on the marketing of our natural gas production and the management of our remaining trading portfolio. Our portfolio includes both contracts with third parties and contracts with affiliates that require physical delivery of a commodity or financial settlement. We continue to consider opportunities to assign, terminate or otherwise accelerate the liquidation of certain of our legacy trading positions which may result in future losses. For a further discussion of the segment's activities, see our 2004 Annual Report on Form 10-K, as amended.

Operating Results

Below are the overall operating results and analysis of these results for our Marketing and Trading segment for the periods ended September 30:

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2005	2004	2005	2004
	(In millions)			
Overall EBIT:				
Gross margin[1]	$(389)	$(120)	$(585)	$(420)
Operating expenses	(15)	(19)	(37)	(48)
Operating loss	(404)	(139)	(622)	(468)
Other income	6	1	9	14
EBIT	$(398)	$(138)	$(613)	$(454)
Gross margin by significant contract type:				
Natural gas and oil contracts				
Production-related and other natural gas derivatives				
Changes in fair value on positions designated as hedges in December 2004	$ —	$(143)	$ —	$(403)
Changes in fair value on other production-related contracts	(390)	—	(508)	—
Changes in fair value on other natural gas positions	(67)	19	52	27
Total production-related and other natural gas derivatives	(457)	(124)	(456)	(376)
Transportation-related contracts				
Demand charges	(39)	(39)	(118)	(118)
Settlements[2]	36	64	84	111
Total transportation-related contracts	(3)	25	(34)	(7)
Total gross margin — natural gas contracts	(460)	(99)	(490)	(383)
Power contracts				
Changes in fair value on Cordova tolling agreement	45	(27)	(66)	(30)
Changes in fair value on other power derivatives	20	(13)	(52)	(26)
Other	6	19	23	19
Total gross margin — power contracts	71	(21)	(95)	(37)
Total gross margin	$(389)	$(120)	$(585)	$(420)

(1) Gross margin for our Marketing and Trading segment consists of revenues from commodity trading and origination activities less the costs of commodities sold, including changes in the fair value of our derivative contracts.

(2) Includes a $50 million gain related to the early termination of an LNG contract in 2004.

During the quarter and nine months ended September 30, 2005, increases in forecasted natural gas prices had a significant negative impact on our production-related contracts. However, in the third quarter of 2005, forecasted power prices increased more than natural gas prices, which positively impacted the fair value of our

Cordova tolling agreement. Listed below is a discussion of factors, by significant contract type, that affected the profitability of this segment during the quarters and nine months ended September 30, 2005 and 2004:

Natural Gas and Oil Contracts

Production-related and other natural gas derivatives

- *Derivatives designated as hedges.* Losses for the quarter and nine months ended September 30, 2004 on our contracts designated as hedges on December 1, 2004, were a result of increases in natural gas prices relative to the fixed prices in these contracts. Following their designation as accounting hedges in the fourth quarter of 2004, the income impacts of these contracts were reflected in our Production segment.

- *Other production-related derivatives.* These option contracts, which are not accounting hedges and are marked to market in our results each period, provide us with various floor and ceiling prices on our future natural gas and oil production. We paid a total net premium of $91 million for these option contracts.

  In addition to the options described above, we hold several derivative contracts that, on a net basis, obligate us to sell 31 TBtu and 1,289 MBbls of our Production segment's anticipated 2005 and 2006 natural gas and oil production at fixed prices.

  Due to increases in natural gas and oil prices, the fair value of these contracts significantly decreased during the quarter and nine months ended September 30, 2005.

- *Other natural gas derivatives.* Other natural gas derivatives consist of physical and financial natural gas contracts. These contracts obligate us to either purchase or sell natural gas at fixed prices. Our exposure to natural gas price changes vary from period to period based on whether we purchase more or less natural gas than we sell under these contracts. Under certain of these contracts, we supply gas to power plants that we partially own, including the MCV and Berkshire power projects. Due to their affiliated nature, we do not recognize mark-to-market gains or losses on these contracts to the extent of our ownership interests. However, should we sell our interests in these plants, we would record the cumulative unrecognized mark-to-market losses on these contracts, which totaled approximately $139 million as of September 30, 2005, net of related hedges.

Transportation-related contracts

Our ability to utilize our transportation-related contracts improved during 2005 due to increased price differentials between the receipt and delivery points for these contracts. Recovered demand charges (in millions) are as follows:

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2005	2004	2005	2004
Alliance Pipeline				
Demand charges	$ 16	$15	$48	$45
Percentage recovered	100%	84%	78%	71%
Texas Interstate				
Demand charges	$ 7	$ 7	$21	$20
Percentage recovered	33%	6%	42%	14%
Other Transportation-related Contracts				
Demand charges	$ 16	$17	$49	$53
Percentage recovered	108%	9%	82%	50%

Power Contracts

Cordova tolling agreement

Our Cordova agreement is sensitive to changes in forecasted natural gas and power prices. During 2004 and the first six months of 2005, forecasted natural gas prices increased relative to power prices, resulting in a decrease in the fair value of the contract. However, during the third quarter of 2005, forecasted power prices increased relative to natural gas prices, resulting in an increase in the value of the contract. We are currently evaluating opportunities to sell or terminate our obligations under this agreement, which may result in future losses.

Other power derivatives

- During the first quarter of 2005, we assigned our contracts to supply power to our Power segment's Cedar Brakes I and II entities to Constellation Energy Commodities Group, Inc. These contracts decreased in fair value by $13 million and $51 million in the quarter and nine months ended September 30, 2004. In conjunction with the transfer, we also entered into derivative contracts with Constellation that swap the locational differences in power prices at the Camden, Bayonne and Newark Bay power plants and the Pennsylvania-New Jersey-Maryland power pool's West Hub through 2013. The fair value of these swaps decreased by $9 million and $22 million during the quarter and nine months ended September 30, 2005, due to unfavorable changes in the power prices at each location.

  In October 2005, we assigned our contracts to supply power to our Power segment's Mohawk River Funding II subsidiary to Merrill Lynch. We will recognize a loss of approximately $30 million associated with these contracts in the fourth quarter of 2005.

- We have a contract to supply power to Morgan Stanley at a fixed price through 2016. This contract decreased in fair value by $146 million and $236 million during the quarter and nine months ended September 30, 2005, and decreased in fair value by $23 million and $68 million during the quarter and nine months ended September 30, 2004. The overall decrease in the fair value of these derivatives resulted from increasing power prices related to these obligations during these periods.

- During the nine months ended September 30, 2005 and 2004, we were required to purchase power under several remaining power contracts, which include those used to manage risk on our power supply obligations. Due to changes in power prices, the fair value of these contracts increased by $175 million and $206 million during the quarter and nine months ended September 30, 2005, and increased by $23 million and $93 million during the same periods of 2004.

Other

- On March 24, 2005, a bankruptcy court entered an order allowing Mohawk River Funding III's bankruptcy claims with USGen New England. We received payment on this claim and recognized a gain of $17 million.

- During the third quarter of 2004, we recorded a $25 million gain related to the termination of a power contract with our Power segment, which was eliminated in El Paso's consolidated results.

Non-regulated Business — Power Segment

As of September 30, 2005, our Power segment primarily consisted of an international power business with an ongoing focus to maximize the value of our assets in Brazil. Our other international power operations are considered non-core activities, and we expect to exit these activities within the next twelve months. Historically, this segment also included domestic power plant operations and a domestic power contract restructuring business. We have sold substantially all of these domestic businesses.

Significant developments in our operations since December 31, 2004 include:

- *Brazil.* Our Macae project in Brazil has a contract that requires Petrobras to make minimum revenue payments until August 2007. Petrobras has not paid amounts due under the contract since December 2004, and has initiated arbitration proceedings related to that obligation. As a result of continued negotiations with Petrobras, we recorded an impairment of this investment in the second quarter of 2005. This impairment was based on information regarding the potential value we would receive from the resolution of this matter. The future financial performance of the Macae plant will be affected by the ultimate outcome of this dispute, the timing of that outcome, and by regional changes in the Brazilian power markets. In addition, in October 2004, our Porto Velho project experienced an outage with a steam turbine, which resulted in a partial reduction in the plant's capacity. The project expects to have the steam turbine back in service by the first quarter of 2006. The Porto Velho project is also negotiating certain provisions of its power purchase agreement and the outcome of these negotiations may impact the future financial performance of the project. For further discussion of these matters, see Item 1, Financial Statements, Note 10.
- *Asia.* During 2005, we announced the sale of our Asian power assets. We recorded impairments on certain of these assets based on information received regarding the potential value we may receive when we sell them. In the third quarter of 2005, we recorded a gain of $109 million upon the sale of our 50 percent interest in the KIECO power facility in Korea. We expect to substantially complete the sale of our remaining Asian assets in early 2006. We will continue to assess the fair value of those assets throughout the sales process, which may result in additional impairments or gains in future periods.
- *Other International Power.* During the second quarter of 2005, we engaged an investment banker to facilitate the sale of our Central American power assets. We recorded an impairment in the second quarter of 2005 based on information received about the value we may receive upon the sale of these assets. We will continue to assess the value of these assets throughout the sales process, which may result in additional impairments that may be significant. See Item 1, Financial Statements, Note 3 for further information on our divestitures.
- *Midland Cogeneration Venture.* In the fourth quarter of 2004, we impaired our investment in MCV based on a decline in the carrying value of the investment due to increased fuel costs. During the third quarter of 2005, we recorded our proportionate share of a significant impairment recorded by MCV. As a result of this impairment, our remaining investment consists solely of our share of MCV's accumulated other comprehensive income. MCV's project owners are pursuing various alternatives which could result in the recovery of some of our previously impaired investment.

Operating Results

Below are the overall operating results and analysis of activities within our Power segment for the periods ended September 30:

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2005	2004	2005	2004
	(In millions)			
Overall EBIT:				
Gross margin[1]	$ 52	$ 155	$ 212	$ 509
Operating expenses				
Loss on long-lived assets	—	(77)	(388)	(333)
Other operating expenses	(68)	(126)	(235)	(372)
Operating loss	(16)	(48)	(411)	(196)
Earnings from unconsolidated affiliates				
Losses from impairments, net of gains on sale	(50)	(11)	(198)	(49)
Equity in earnings	8	36	69	114
Other income	17	16	68	57
EBIT	$(41)	$ (7)	$(472)	$ (74)

[1] Gross margin for our Power segment consists of revenues from our power plants and the revenues, cost of electricity purchases and changes in fair value of restructured power contracts. The cost of fuel used in the power generation process is included in operating expenses.

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2005	2004	2005	2004
	(In millions)			
EBIT by Area:				
Brazil				
Impairments	$ —	$(32)	$(294)	$(183)
Earnings from consolidated and unconsolidated plant operations	12	57	38	163
Asia and Other International Power				
Impairments, net[1]	—	—	(258)	(5)
Gain on sale of KIECO power plant	109	—	109	—
Dividend on investment fund	1	—	17	—
Gain on sale of PPN power plant	—	—	22	—
Earnings from consolidated and unconsolidated plant operations	5	17	36	53
Domestic Power				
Power Contract Restructurings:				
Favorable resolution of bankruptcy claim	—	—	53	—
Impairments, net[1]	—	—	—	(96)
Change in fair value of contracts	—	21	11	79
Losses from MCV investment	(159)	—	(162)	—
Other Domestic Operations	(2)	(54)	(7)	(48)
Other[2]	(7)	(16)	(37)	(37)
EBIT	$(41)	$ (7)	$(472)	$ (74)

[1] Includes impairment charges and gains (losses) on sales of assets and investments, net of any related minority interest.

[2] Other consists of the indirect expenses and general and administrative costs associated with our domestic and international operations. It also includes a $15 million impairment of power turbines recorded in the first quarter of 2005.

Brazil. During the quarter and nine months ended September 30, 2005 we did not recognize approximately $53 million and $152 million of revenues at Macae based on non-payment of these amounts by Petrobras. Partially offsetting this decline in revenue were lower insurance and general and administrative costs associated with our Brazilian operations. During the first quarter of 2004, we recorded an impairment of our Manaus and Rio Negro power plants and, in the third quarter of 2004, impaired our related receivables based on the status of our negotiations to extend their power contracts, which was negatively impacted by changes in the Brazilian political environment.

Asia and Other International Power. During the first half of 2005, we recorded impairments, net of gains on sales and minority interests, of $130 million on our Asian power assets, $111 million on our Central American assets, and $17 million on other foreign power investments based on the expected value we would receive upon sale or anticipated sale of these assets.

In addition to these impairments, we did not recognize approximately $4 million and $23 million of earnings for the quarter and nine months ended September 30, 2005 on our Asian power investments and $5 million for the quarter and nine months ended September 30, 2005 on our Central American power investments, since we did not believe these amounts could be realized.

Domestic Power Contract Restructurings. On March 24, 2005, a bankruptcy court entered an order affirming MRF III's bankruptcy claims with USGen New England. In June 2005, we received payment on this claim and recognized a gain of $53 million.

In October 2005, we sold our interest in Mohawk River Funding II, a wholly owned subsidiary which held our remaining restructured power contract and related debt. We will recognize a loss of approximately $5 million in our Power segment in the fourth quarter of 2005 related to this sale. With the completion of this sale and the sale of Cedar Brakes I and II in the first quarter of 2005, we have sold all of our domestic power contract restructuring business. As a result, in 2005, there was a substantial reduction in these operations compared to changes in the fair value of these contracts that occurred during 2004. During the first quarter of 2004, we recorded a loss of $98 million related to the announced sale of Utility Contract Funding and its restructured power contract and related debt.

Other Domestic Operations. During the quarter and nine months ended September 30, 2004, we recorded earnings from consolidated and unconsolidated affiliates of approximately $5 million and $53 million, including a $25 million loss on the termination of a power contract with our Marketing and Trading segment related to one of these assets. This loss was eliminated in El Paso's consolidated results. We also recorded impairments, net of realized gains and losses, of approximately $57 million and $102 million during the quarter and nine months ended September 30, 2004 on our domestic power plants to adjust their book value to their estimated sales proceeds.

Non-regulated Business — Field Services Segment

Our Field Services segment has historically conducted our midstream activities. In 2004, these activities included our gathering and processing operations in south Texas and south Louisiana and our general and limited partner interests in GulfTerra and Enterprise. In late 2004, we sold our interests in GulfTerra and our gathering and processing assets in south Texas to Enterprise, and in early 2005, we sold to Enterprise our remaining common and general partner interests in Enterprise and our interests in the Indian Springs natural gas gathering and processing assets.

During the second and third quarter of 2005, we announced the sale of our south Louisiana gathering and processing assets and our interest in the Javelina natural gas processing and pipeline assets for approximately $642 million. Our south Louisiana operations are reported as discontinued operations for the nine months ended September 30, 2005. However, prior period amounts were not adjusted as these operations were not material to prior period results or historical trends. We completed the sale of Javelina in the fourth quarter of 2005, and will record a gain of approximately $100 million.

For the quarter and nine months ended September 30, 2005, EBIT in our Field Services segment was a loss of $22 million and earnings of $157 million as compared to earnings of $61 million and $124 million during the same periods of 2004 due to the following:

	Favorable (Unfavorable) EBIT Impact For the Quarter Ended September 30, 2005 Compared to 2004	Favorable (Unfavorable) EBIT Impact For the Nine Months Ended September 30, 2005 Compared to 2004
	(In millions)	
Gathering and processing margins	$ (46)	$(125)
Operating expenses	22	78
Enterprise/GulfTerra related transactions		
Gain on sale of GP interest and common units to Enterprise in 2005	—	183
Gain on sale of interest in GulfTerra and south Texas processing assets to Enterprise in 2005 and 2004	(500)	(500)
Goodwill impairment in 2004	480	480
Equity earnings	(32)	(98)
Minority interest	11	32
Impairment of Indian Springs in 2004	13	13
Termination of Needle Mountain gas supply contract in 2005	(28)	(28)
Other	(3)	(2)
Total increase (decrease) in EBIT	$ (83)	$ 33

During the quarter and nine months ended September 30, 2005, we experienced a decrease in our gathering and processing operations as compared to the same period in 2004, primarily as a result of the asset sales discussed above.

For a discussion of our historical ownership interests in Enterprise and activities with the partnership, see Item 1, Financial Statements, Note 14. For a discussion of our discontinued operations associated with our gathering and processing assets, see Item 1, Financial Statements Note 3. For a further discussion of the historical business activities of our Field Services segment, see our 2004 Annual Report on Form 10-K, as amended.

Corporate, Net

Our corporate operations include our general and administrative functions as well as a telecommunications business and various other contracts and assets, all of which are immaterial to our results.

For the quarter and nine months ended September 30, 2005, EBIT in our corporate operations was lower than the same periods in 2004 due to the following:

	Favorable (Unfavorable) EBIT Impact For Quarter Ended September 30, 2005 Compared to 2004	Favorable (Unfavorable) EBIT Impact For Nine Months Ended September 30, 2005 Compared to 2004
	(In millions)	
Western Energy Settlement charge in 2005[1]	$ —	$ (59)
Losses on early extinguishment of debt in 2005 and 2004	5	(24)
Lease termination costs due to office consolidation	30	3
Change in litigation, insurance and other reserves	(46)	(62)
Other	1	(6)
Total decrease in EBIT	$(10)	$(148)

(1) In the first quarter of 2005, we incurred this $59 million charge associated with the payment of the Western Energy Settlement obligation earlier than originally expected. This charge has been recorded in operations and maintenance expense.

We have a number of pending litigation matters, including shareholder and other lawsuits filed against us. In each of our legal and insurance matters, we evaluate its merits and our defenses. Adverse rulings against us and/or unfavorable settlements related to these and other legal matters would impact our future results.

As discussed in Item I, Financial Statements, Note 4, we had an accrual as of December 31, 2004 related to our remaining lease obligations associated with the consolidation of our Houston-based operations. Our estimated costs were based on a discounted liability, which included estimates of future sublease rentals. During the second quarter of 2005, we recorded additional charges of $27 million related to vacating the remaining leased space and signing a termination agreement related to this lease obligation. During the third quarter of 2004, we recorded a charge of $30 million associated with vacating the leased space.

Interest and Debt Expense

Interest and debt expense for the quarter and nine months ended September 30, 2005, was $52 million and $195 million lower than the same periods in 2004. Below is an analysis of our interest expense for the periods ended September 30:

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2005	2004	2005	2004
	(In millions)			
Long-term debt, including current maturities	$332	$376	$1,006	$1,171
Other	12	20	28	58
Total interest and debt expense	$344	$396	$1,034	$1,229

During the quarter and nine months ended September 30, 2005, our total interest and debt expense decreased primarily due to the retirements of long-term debt and other financing obligations (net of issuances). See Item 1. Financial Statements, Note 9, for a further discussion of our activities related to debt repayments and issuances.

Income Taxes

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

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2005	2004	2005	2004
	(In millions, except for rates)			
Income taxes	$(108)	$77	$(165)	$135
Effective tax rate	25%	(62)%	27%	(89)%

For a discussion of our effective tax rates, see Item 1, Financial Statements, Note 6.

In October 2004, the American Jobs Creation Act of 2004 was signed into law. This legislation creates, among other things, a temporary incentive for U.S. multinational companies to repatriate accumulated income earned outside the U.S. at an effective tax rate of 5.25 percent. We have determined that we will not repatriate any foreign earnings under this legislation and, as a result, it will not have an impact on our financial statements.

Discontinued Operations

As of September 30, 2005, we have petroleum markets operations, international natural gas and oil production operations outside of Brazil, and gathering and processing operations in south Louisiana that are classified as discontinued operations in our financial statements. Our south Louisiana gathering and processing assets were approved for sale by our Board of Directors during the second quarter of 2005. Accordingly, these assets and the results of their operations for the quarter and nine months ended September 30, 2005, have been reflected as discontinued operations. Prior period amounts have not been adjusted as these operations did not materially impact prior period results or historical trends. In the fourth quarter of 2005, we completed the sale of our south Louisiana gathering and processing assets for approximately $486 million, which will result in a fourth quarter pretax gain of approximately $400 million.

Our loss from discontinued operations for the nine months ended September 30, 2004 consisted of losses of $80 million in our petroleum markets operations, primarily related to losses on the completed sales of our Eagle Point and Aruba refineries along with other operational and severance costs and $38 million of losses in our international production operations, primarily from impairments and losses on sales.

Commitments and Contingencies

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

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

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

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

Forward-looking statements are subject to risks and uncertainties. While we believe the assumptions or bases underlying the forward-looking statements are reasonable and are made in good faith, we caution that assumed facts or bases almost always vary from actual results, and these variances can be material, depending upon the circumstances. We cannot assure you that the statements of expectation or belief contained in the forward-looking statements will result or be achieved or accomplished. Important factors that could cause actual results to differ materially from estimates or projections contained in forward-looking statements are described in our 2004 Annual Report on Form 10-K, as amended.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

This information updates, and you should read it in conjunction with, information disclosed in our 2004 Annual Report on Form 10-K, as amended, in addition to the information presented in Items 1 and 2 of this Quarterly Report on Form 10-Q.

There are no material changes in our quantitative and qualitative disclosures about market risks from those reported in our 2004 Annual Report on Form 10-K, as amended, except as presented below:

Market Risk

We are exposed to a variety of market risks in the normal course of our business activities, including commodity price, foreign exchange and interest rate risks. We measure risks on the derivative and non-derivative contracts in our trading portfolio on a daily basis using a Value-at-Risk model. We measure our Value-at-Risk using a historical simulation technique, and we prepare it based on a confidence level of 95 percent and a one-day holding period. This Value-at-Risk was $58 million as of September 30, 2005 and $16 million as of December 31, 2004, and represents our potential one-day unfavorable impact on the fair values of our trading contracts. Our Value-at-Risk increased significantly during 2005 due to several financial swaps and option contracts that we entered into during 2004 and 2005 to provide price protection on a portion of our Production segment's anticipated natural gas and oil production. These contracts significantly increased our exposure to market changes in natural gas and oil prices, which experienced significant volatility during 2005 and may continue into the future.

Interest Rate Risk

As of September 30, 2005 and December 31, 2004, we had $56 million and $665 million of third party long-term restructured power derivative contracts. In March 2005, we sold Cedar Brakes I and II, which held two power derivative contracts with a combined fair value of $596 million as of December 31, 2004. Additionally, in October 2005, we sold our interest in Mohawk River Funding II, a wholly-owned subsidiary which held our remaining restructured power contract. These sales substantially reduced our exposure to interest rate risks.

Item 4. Controls and Procedures

Material Weaknesses Previously Disclosed

As discussed in our 2004 Annual Report on Form 10-K, as amended, we did not maintain effective controls as of December 31, 2004, over (1) access to financial application programs and data in certain information technology environments, (2) account reconciliations and (3) identification, capture and communication of financial data used in accounting for non-routine transactions or activities. The remedial actions implemented in 2005 related to these material weaknesses are described below.

Evaluation of Disclosure Controls and Procedures

As of September 30, 2005, we carried out an evaluation under the supervision and with the participation of our management, including our Chief Executive Officer (CEO) and our Chief Financial Officer (CFO), as to the effectiveness, design and operation of our disclosure controls and procedures (pursuant to Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the Exchange Act)). As discussed below, we have made various changes in our internal controls which we believe remediate the material weaknesses previously identified by the company. We are relying on those changes in internal controls as an integral part of our disclosure controls and procedures. Based upon the results of the evaluation of our disclosure controls and procedures and based upon our reliance on these revised internal controls, management, including our CEO and CFO, concluded that our disclosure controls and procedures were effective as of September 30, 2005.

Changes in Internal Control Over Financial Reporting

During the first and second quarters of 2005, we implemented the following changes in our internal control over financial reporting:

- Implemented automated and manual controls for our primary financial system to monitor unauthorized password changes;
- Performed an in-depth analysis of our primary financial accounting system to examine existing functional access to identify any potentially incompatible duties and developed an enhanced segregation of duties matrix based on this analysis;
- Modified our primary financial accounting system to eliminate or modify potentially conflicting functionality;
- Rewrote the computer programs for Marketing and Trading's mark-to-market accounting system to significantly reduce the number of different combinations of user access and to modify remaining capabilities to eliminate potentially conflicting duties;
- Implemented a process to evaluate all new user access requests against segregation of duties matrices to ensure no new conflicts are created for our applications described above;
- Separated security administration rights from system update capabilities for our applications described above;
- Implemented monitoring procedures to monitor activities of security administration roles for our applications described above;
- Formalized, issued and implemented various accounting policies including a company-wide account reconciliation policy and an accounting policy that requires a higher level of review of non-routine transactions;
- Implemented an account reconciliation monitoring tool that also allows for aggregation of unreconciled amounts;

- Provided additional training regarding the company-wide account reconciliation policy and appropriate use of the account reconciliation monitoring tool;
- Developed and improved processes to ensure adequate communication between commercial and accounting personnel to allow for the complete and timely identification, communication and review of information required to record non-routine transactions; and
- Established a more rigorous top-down review of the financial statements at the management, corporate and Disclosure Committee levels.

During the third quarter of 2005, we also implemented the following various changes in our internal control over financial reporting, including:

- Conducted further training on company-wide accounting policies.
- Improved our procedures for managing information systems changes; and
- Enhanced the automated controls over the preparation and posting of journal entries.

We believe that the changes in our internal controls described above have remediated the material weaknesses identified in connection with our assessment of internal controls as of December 31, 2004. Our testing and evaluation of the operating effectiveness and sustainability of many of the changes in internal controls have not been completed at this time. As a result, we may identify additional changes that are required to remediate or improve our internal control over financial reporting.

PART II — OTHER INFORMATION

Item 1. Legal Proceedings

See Part I, Item 1, Note 10, which is incorporated herein by reference. Additional information about our legal proceedings can be found below and in Part I, Item 3 of our 2004 Annual Report on Form 10-K, as amended, filed with the Securities and Exchange Commission.

Coastal Eagle Point Air Issues. On April 1, 2004, the New Jersey Department of Environmental Protection issued an Administrative Order and Notice of Civil Administrative Penalty Assessment seeking $183,000 in penalties for excess emission events that occurred during the fourth quarter of 2003 at our former Eagle Point refinery. We filed an administrative appeal contesting the allegations and penalty. We have reached an agreement to resolve the allegations and appeal for a penalty for $119,400, and have executed the settlement agreement. We will be paying the agreed penalty in the fourth quarter of 2005.

Corpus Christi Refinery Air Violations. On March 18, 2004, the Texas Commission on Environmental Quality (TCEQ) issued an "Executive Director's Preliminary Report and Petition" seeking $645,477 in penalties relating to air violations alleged to have occurred at El Paso's former Corpus Christi, Texas refinery from 1996 to 2000. We subsequently filed a hearing request to protect our procedural rights. In March 2005, the parties reached an agreement in principle to resolve the allegations for $272,097. In September 2005, the parties finalized the written terms of the settlement agreement. The final terms allow for $136,049 to be paid as a penalty and $136,049 to be spent on a supplemental environmental project. El Paso executed the agreement on September 22, 2005 and forwarded it to the TCEQ with the penalty payment of $136,049. The proposed settlement is scheduled to be considered for approval at the December 14, 2005 TCEQ meeting.

EPNG Arizona Pipe-Coating. In September 2005, the State of Arizona, on behalf of the Arizona Department of Environmental Quality (ADEQ), informed EPNG of its intent to require a civil penalty and preventive actions by EPNG to resolve a Notice of Violation issued by the ADEQ for alleged regulatory violations related to its handling of asbestos-containing asphaltic pipe coating. The likely penalty and costs associated with any preventive actions are unknown at this time.

Natural Buttes. In May 2003, we met with the EPA to discuss potential prevention of significant deterioration violations due to a de-bottlenecking modification at Colorado Interstate Gas Company's facility. The EPA issued an Administrative Compliance Order and we were in negotiations with the EPA as to the appropriate penalty. In September 2005, we were informed that the EPA referred this matter to the U.S. Department of Justice. We have since entered into a tolling agreement with the U.S. in order to facilitate continuing settlement discussions.

Shoup Natural Gas Processing Plant. On December 16, 2003, El Paso Field Services, L.P. received a Notice of Enforcement (NOE) from the TCEQ concerning alleged Clean Air Act violations at its Shoup, Texas plant. The alleged violations pertained to emission limit, testing, reporting and recordkeeping issues in 2001. On December 29, 2004, TCEQ issued an Executive Director's Preliminary Report and Petition revising the allegations from the NOE and seeking a penalty of $419,650. We answered the Petition disputing the allegations and the penalty. We have reached an agreement to resolve the matter by agreeing to pay a penalty of $106,439 and conduct a supplemental environmental project costing $95,961. We paid the penalty to TCEQ and will perform the supplemental environmental project upon final execution of the settlement by TCEQ.

Item 2. Unregistered Sales of Equity 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

Each exhibit identified below is a part of this Report. Exhibits filed with this Report are designated by an "*". Exhibits designated by "**" are furnished with this Report pursuant to Item 601(b)(32) of Regulation S-K. All exhibits not so designated are incorporated herein by reference to a prior filing as indicated.

Exhibit Number	Description
4.A	Ninth Supplemental Indenture dated as of July 1, 2005 between El Paso Corporation and HSBC Bank USA, National Association, as trustee (Exhibit 4.A to our Form 8-K filed on July 1, 2005).
4.B	Form of 7.625% Senior Note Due August 16, 2007 (included in Exhibit 4.A to our Form 8-K filed July 1, 2005).
10.A	El Paso Corporation Employee Stock Purchase Plan, Amended and Restated Effective as of July 1, 2005 (Exhibit 10.E to our Form 10-Q filed on August 5, 2005).
10.B	Registration Rights Agreement as of July 1, 2005 between El Paso Corporation and Credit Suisse First Boston LLC (Exhibit 10.A to our Form 8-K filed on July 1, 2005).
10.C	Form of Indemnification Agreement executed by El Paso for the benefit of each officer listed in Schedule A thereto, effective August 4, 2005 (Exhibit 10.G to our Form 10-Q filed on August 5, 2005).
10.D	Credit Agreement among El Paso Corporation and El Paso Production Oil & Gas USA, L.P., as Borrowers, Fortis Capital Corp., as Administrative Agent, Arranger and Bookrunner, dated as of November 3, 2005 (Exhibit 10.A to our Form 8-K filed on November 4, 2005).
*31.A	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.B	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
**32.A	Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
**32.B	Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

Undertaking

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

SIGNATURES

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

EL PASO CORPORATION

Date: November 4, 2005

/s/ D. MARK LELAND

D. Mark Leland
Executive Vice President and
Chief Financial Officer
(Principal Financial Officer)

Date: November 4, 2005

/s/ JEFFREY I. BEASON

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