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

Form 10-Q

(Mark One)

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

For the quarterly period ended June 30, 2004

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 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 19, 2004: 643,226,654

EL PASO CORPORATION

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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	TBtu	= trillion British thermal units
MBbls	= thousand barrels	MW	= megawatt
Mcf	= thousand cubic feet		

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. Oil includes natural gas liquids unless otherwise specified. 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 June 30,		Six Months Ended June 30,	
	2004	2003 (Restated)	2004	2003 (Restated)
Operating revenues	$1,524	$ 1,569	$3,081	$ 3,397
Operating expenses				
Cost of products and services	435	448	825	1,053
Operation and maintenance	373	625	774	1,181
Depreciation, depletion and amortization	263	302	538	614
Loss on long-lived assets	17	395	239	409
Taxes, other than income taxes	66	71	130	148
	1,154	1,841	2,506	3,405
Operating income (loss)	370	(272)	575	(8)
Earnings (losses) from unconsolidated affiliates	98	86	198	(48)
Other income	50	46	103	83
Other expense	(20)	(87)	(36)	(129)
Interest and debt expense	(410)	(463)	(833)	(877)
Distributions on preferred interests of consolidated subsidiaries	(6)	(17)	(12)	(38)
Income (loss) before income taxes	82	(707)	(5)	(1,017)
Income taxes	37	(410)	47	(513)
Income (loss) from continuing operations	45	(297)	(52)	(504)
Discontinued operations, net of income taxes	(29)	(939)	(138)	(1,154)
Cumulative effect of accounting changes, net of income taxes	—	—	—	(9)
Net income (loss)	$ 16	$(1,236)	$ (190)	$(1,667)
Basic and diluted income (loss) per common share				
Income (loss) from continuing operations	$ 0.07	$ (0.50)	$(0.08)	$ (0.84)
Discontinued operations, net of income taxes	(0.04)	(1.57)	(0.22)	(1.94)
Cumulative effect of accounting changes, net of income taxes	—	—	—	(0.02)
Net income (loss) per common share	$ 0.03	$ (2.07)	$(0.30)	$ (2.80)
Basic and diluted average common shares outstanding	639	596	639	595
Dividends declared per common share	$ 0.04	$ 0.04	$ 0.08	$ 0.08

See accompanying notes.

EL PASO CORPORATION

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

	June 30, 2004	December 31, 2003
ASSETS		
Current assets		
Cash and cash equivalents	$ 1,411	$ 1,429
Accounts and notes receivable		
Customers, net of allowance of $252 in 2004 and $272 in 2003	1,487	2,039
Affiliates	138	189
Other	256	245
Inventory	157	181
Assets from price risk management activities	467	706
Assets held for sale and from discontinued operations	1,281	2,538
Restricted cash	236	590
Deferred income taxes	328	592
Other	356	413
Total current assets	6,117	8,922
Property, plant and equipment, at cost		
Pipelines	18,839	18,563
Natural gas and oil properties, at full cost	14,945	14,689
Power facilities	1,591	1,660
Gathering and processing systems	309	334
Other	923	998
	36,607	36,244
Less accumulated depreciation, depletion and amortization	18,258	18,049
Total property, plant and equipment, net	18,349	18,195
Other assets		
Investments in unconsolidated affiliates	3,517	3,551
Assets from price risk management activities	1,415	2,338
Goodwill and other intangible assets, net	1,077	1,082
Other	2,252	2,996
	8,261	9,967
Total assets	$32,727	$37,084

See accompanying notes.

EL PASO CORPORATION

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

	June 30, 2004	December 31, 2003
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Accounts payable		
Trade	$ 1,144	$ 1,552
Affiliates	25	26
Other	337	438
Short-term financing obligations, including current maturities	1,574	1,457
Liabilities from price risk management activities	632	734
Western Energy Settlement	44	633
Liabilities related to assets held for sale and discontinued operations	268	933
Accrued interest	327	391
Other	794	910
Total current liabilities	5,145	7,074
Long-term financing obligations	18,259	20,275
Other		
Liabilities from price risk management activities	887	781
Deferred income taxes	1,335	1,571
Western Energy Settlement	354	415
Other	1,993	2,047
	4,569	4,814
Commitments and contingencies		
Securities of subsidiaries	448	447
Stockholders' equity		
Common stock, par value $3 per share; authorized 1,500,000,000 shares; issued 650,370,099 shares in 2004 and 639,299,156 shares in 2003	1,950	1,917
Additional paid-in capital	4,580	4,576
Accumulated deficit	(1,975)	(1,785)
Accumulated other comprehensive income	2	11
Treasury stock (at cost); 7,432,519 shares in 2004 and 7,097,326 shares in 2003	(223)	(222)
Unamortized compensation	(28)	(23)
Total stockholders' equity	4,306	4,474
Total liabilities and stockholders' equity	$32,727	$37,084

See accompanying notes.

EL PASO CORPORATION

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

	Six Months Ended June 30,	
	2004	2003 (Restated)[1]
Cash flows from operating activities		
Net loss	$ (190)	$(1,667)
Less loss from discontinued operations, net of income taxes	(138)	(1,154)
Net loss before discontinued operations	(52)	(513)
Adjustments to reconcile net loss to net cash from operating activities		
Depreciation, depletion and amortization	538	614
Loss on long-lived assets	239	409
(Earnings) losses from unconsolidated affiliates, adjusted for cash distributions	(40)	162
Deferred income taxes	26	(541)
Cumulative effect of accounting changes	—	9
Other non-cash items	60	312
Asset and liability changes	(636)	467
Cash provided by continuing operations	135	919
Cash provided by discontinued operations	161	95
Net cash provided by operating activities	296	1,014
Cash flows from investing activities		
Additions to property, plant and equipment	(782)	(1,266)
Purchases of interests in equity investments	(21)	(20)
Net proceeds from the sale of assets and investments	165	1,282
Cash paid for acquisitions, net of cash acquired	2	(1,078)
Net change in restricted cash	447	(105)
Net change in notes receivable from unconsolidated affiliates	98	(79)
Other	—	25
Cash used in continuing operations	(91)	(1,241)
Cash provided by discontinued operations	1,113	245
Net cash provided by (used in) investing activities	1,022	(996)
Cash flows from financing activities		
Payments to retire long-term debt and other financing obligations	(1,024)	(1,599)
Net proceeds from the issuance of long-term debt and other financing obligations	50	3,086
Dividends paid	(49)	(154)
Payments to redeem preferred interests of consolidated subsidiaries	—	(1,177)
Contributions from discontinued operations	909	340
Issuances of common stock, net	73	—
Other	(21)	20
Cash provided by (used in) continuing operations	(62)	516
Cash used in discontinued operations	(1,274)	(340)
Net cash provided by (used in) financing activities	(1,336)	176
Change in cash and cash equivalents	(18)	194
Cash and cash equivalents		
Beginning of period	1,429	1,591
End of period	$1,411	$ 1,785

[1] Only individual line items in cash flows from operating activities have been restated. Total cash flows from continuing operating, investing and financing activities, as well as discontinued operations, were unaffected.

See accompanying notes.

EL PASO CORPORATION

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

	Quarter Ended June 30,		Six Months Ended June 30,	
	2004	2003 (Restated)	2004	2003 (Restated)
Net income (loss)	$ 16	$(1,236)	$(190)	$(1,667)
Foreign currency translation adjustments	(39)	58	(25)	116
Unrealized net gains (losses) from cash flow hedging activity				
Unrealized mark-to-market gains (losses) arising during period (net of income taxes of $2 and $12 in 2004 and $19 and $42 in 2003)	(4)	17	(23)	70
Reclassification adjustments for changes in initial value to the settlement date (net of income taxes of $7 and $15 in 2004 and $5 and $27 in 2003)	24	(13)	39	(59)
Other comprehensive income (loss)	(19)	62	(9)	127
Comprehensive loss	$ (3)	$(1,174)	$(199)	$(1,540)

See accompanying notes.

EL PASO CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

1. Basis of Presentation and Significant Events Update

Basis of Presentation

We prepared this Quarterly Report on Form 10-Q under the rules and regulations of the U.S. 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 2003 Annual Report on Form 10-K, which includes a summary of our significant accounting policies and other disclosures. The financial statements as of June 30, 2004, and for the quarters and six months ended June 30, 2004 and 2003, are unaudited. We derived the balance sheet as of December 31, 2003, from the audited balance sheet filed in our 2003 Annual Report on Form 10-K. 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. Our results for all periods presented have been reclassified to reflect our Canadian and certain other international natural gas and oil production operations as discontinued operations. Also, our results for the quarter and six months ended June 30, 2003 have been restated to reflect the accounting impact of a reduction in our historically reported proved natural gas and oil reserves and to revise the manner in which we accounted for certain hedges, primarily those associated with our anticipated natural gas and oil production. These restatements are further discussed in our 2003 Annual Report on Form 10-K. Finally, the prior period information presented in these financial statements includes reclassifications which were made to conform to the current period presentation. These reclassifications had no effect on our previously reported net income or stockholders' equity.

Business Update

In December 2003, our management presented its Long-Range Plan for the company. This plan, among other things, defined our core businesses, established a timeline for debt reductions and sales of non-core businesses and assets and set financial goals for the future. During 2004, and through the filing date of this Form 10-Q, we have made significant progress in the areas outlined in that plan, including:

- completing or announcing sales of assets and investments of approximately $3.3 billion (see Note 4);
- retiring, eliminating, or refinancing approximately $3.4 billion of debt and other obligations ($1.9 billion through June 30, 2004) (see Note 11);
- finalizing the Western Energy Settlement, which substantially resolved our principal exposure relating to the western energy crisis and successfully raising funds to satisfy a significant portion of our current obligations under that settlement (see Note 12); and
- entering into a new credit agreement to refinance our existing revolving credit facility with an aggregate of $3 billion in financings consisting of a $1.25 billion, five year term loan, a new $1.0 billion, three year revolving credit facility, and a five year, $750 million funded letter of credit facility, all of which will become available to us upon the filing of this Quarterly Report on Form 10-Q (see Note 11).

Liquidity Update

We believe that the restatement of our historical financial statements mentioned above would have constituted an event of default under our existing revolving credit facility and various other financing transactions; specifically under the provisions in these arrangements related to representations and warranties on the accuracy of our historical financial statements and on our debt to total capitalization ratio. During 2004, we received several waivers on our existing revolving credit facility and various other financing arrangements to address these issues. With the filing of these financial statements, we are in compliance with our existing revolving credit facility and with the various other financings on which we received waivers. Three of our subsidiaries have indentures associated with their public debt that contain $5 million cross-acceleration provisions. These indentures state that should an event of default occur resulting in the acceleration of other debt obligations of such subsidiaries in excess of $5 million, the long-term debt obligations containing such provisions could be accelerated. The acceleration of our debt would adversely affect our liquidity position, and in turn, our financial condition. Our subsidiary, El Paso CGP Company, has not yet filed its financial statements for the second quarter of 2004, as required under several of its financing arrangements. We believe we will file El Paso CGP's financial statements prior to any notice being given or within the allowed time frames under these arrangements such that there will be no event of default.

Our existing revolving credit facility matures in June 2005. As of June 30, 2004, we had $600 million outstanding (which was repaid in September 2004) and $1.1 billion of letters of credit issued under this facility. In November 2004, we entered into a new credit agreement with a group of lenders for an aggregate of $3 billion in financings that will become available to us upon the filing of this Form 10-Q. This new credit agreement will replace our existing revolving credit facility and will consist of a $1.25 billion, five year term loan, a new $1 billion, three year revolving credit facility under which we can issue letters of credit, and an additional five year, $750 million funded letter of credit facility. The letter of credit facility will provide us the ability to issue letters of credit or borrow any unused capacity as loans. The new credit agreement will be collateralized by our interests in El Paso Natural Gas Company (EPNG), Tennessee Gas Pipeline Company (TGP), ANR Pipeline Company (ANR), Colorado Interstate Gas Company (CIG), Wyoming Interstate Gas Company (WIC), ANR Storage Company, and Southern Gas Storage Company.

Our new credit agreement will provide approximately $220 million in net additional borrowing availability as compared to our existing revolving credit facility. Upon the closing of the new credit agreement, letters of credit of approximately $1.2 billion issued under our existing revolving credit facility will be supported by the $750 million letter of credit facility and by approximately $0.4 billion of the new $1 billion revolving credit facility. We will use the $1.25 billion term loan proceeds to repay certain financing obligations, manage our liquidity, prepay upcoming debt maturities, and provide for other general corporate purposes.

Our subsidiaries are a significant potential source of liquidity to us, and they participate in our cash management program to the extent they are permitted to do so under their financing agreements and indentures. Under the cash management program, depending on whether participating subsidiaries have short-term cash requirements or surpluses, we either provide cash to them or they provide cash to us. If we were to incur an event of default under our credit facilities, we would be unable to obtain cash from our pipeline subsidiaries, which are the primary source of cash under this program. In addition, our ownership in a number of our subsidiaries and investments currently serves as collateral under our existing revolving credit facility and our other financings, and will serve as collateral under the new credit agreement. If the lenders were to exercise their rights to this collateral, we could lose our ownership interest in these subsidiaries or be required to liquidate these investments.

We believe we will be able to meet our ongoing liquidity and cash needs through a combination of sources, including cash on hand, cash generated from our operations, borrowings under our new credit agreement, proceeds from asset sales, reduction of discretionary capital expenditures and the possible issuance of long-term debt, and common or preferred equity securities. However, a number of factors could influence our liquidity sources, as well as the timing and ultimate outcome of our ongoing efforts and plans.

2. Significant Accounting Policies

Our significant accounting policies are discussed in our 2003 Annual Report on Form 10-K. The information below provides updating information or required interim disclosures with respect to those policies or disclosure where our policies have changed.

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 income (loss) and income (loss) per share had we applied SFAS No. 123:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2004	2003	2004	2003
	(In millions)			
Net income (loss) as reported	$ 16	$(1,236)	$ (190)	$(1,667)
Add: Stock-based compensation expense in net income (loss), net of taxes	7	16	11	27
Deduct: Stock-based compensation expense determined under fair value-based method for all awards, net of taxes	11	25	21	52
Pro forma net income (loss)	$ 12	$(1,245)	$ (200)	$(1,692)
Income (loss) per share:				
Basic and diluted, as reported	$0.03	$ (2.07)	$(0.30)	$ (2.80)
Basic and diluted, pro forma	$0.02	$ (2.09)	$(0.31)	$ (2.84)

Consolidation of Variable Interest Entities

In January 2003, the FASB issued Financial Interpretation (FIN) No. 46, *Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51.* This interpretation defines a variable interest entity as a legal entity whose equity owners do not have sufficient equity at risk 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 returns, including fees paid by the entity. In December 2003, the FASB issued FIN No. 46-R, which amended FIN No. 46 to extend its effective date until the first quarter of 2004 for all types of entities, except special purpose entities. In addition, FIN No. 46-R limited the scope of FIN No. 46 to exclude certain joint ventures or other entities that meet the characteristics of businesses.

On January 1, 2004, we adopted this standard. Upon adoption, we consolidated Blue Lake Gas Storage Company and several other minor entities and deconsolidated a previously consolidated entity, EMA Power Kft. The overall impact of these actions is described in the following table:

	Increase/(Decrease)
	(In millions)
Restricted cash	$ 34
Accounts and notes receivable from affiliates	(54)
Investments in unconsolidated affiliates	(5)
Property, plant, and equipment, net	37
Other current and non-current assets	(15)
Long-term financing obligations	15
Other current and non-current liabilities	(4)
Minority interest of consolidated subsidiaries	(14)

Blue Lake Gas Storage owns and operates a 47 Bcf gas storage facility in Michigan. One of our subsidiaries operates the natural gas storage facility and we inject and withdraw all natural gas stored in the facility. We own a 75 percent equity interest in Blue Lake. This entity has $11 million of third party debt as of June 30, 2004 that is non-recourse to us. We consolidated Blue Lake because we are allocated a majority of Blue Lake's losses and returns through our equity interest in Blue Lake.

EMA Power Kft owns and operates a 69 gross MW dual-fuel-fired power facility located in Hungary. We own a 50 percent equity interest in EMA. Our equity partner has a 50 percent interest in EMA, supplies all of the fuel consumed and purchases all of the power generated by the facility. Our exposure to this entity is limited to our equity interest in EMA, which was approximately $33 million as of June 30, 2004. We deconsolidated EMA because our equity partner is allocated a majority of EMA's losses and returns through its equity interest and its fuel supply and power purchase agreements with EMA.

We have significant interests in a number of other variable interest entities. We were not required to consolidate these entities under FIN No. 46 and, as a result, our method of accounting for these entities did not change. As of January 1, 2004, these entities consisted primarily of 25 equity investments held in our Power segment that had interests in power generation and transmission facilities with a total generating capacity of approximately 8,100 gross MW. We operate many of these facilities but do not supply a significant portion of the fuel consumed or purchase a significant portion of the power generated by these facilities. The long-term debt issued by these entities is recourse only to the power project. As a result, our exposure to these entities is limited to our equity investments in and advances to the entities ($1.7 billion as of June 30, 2004) and our guarantees and other agreements associated with these entities (a maximum of $134 million as of June 30, 2004).

During our adoption 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 250 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 $25 million to $30 million per year related to its power plants. The following is a summary of the financial statement impacts of our transactions with this entity for the six months ended June 30:

	2004	2003
	(In millions)	
Operating revenues	$ (3)	$ 7
Current liabilities from price risk management activities	(17)	(15)
Non-current liabilities from price risk management activities	(6)	(93)

Accounting for Asset Retirement Obligations

On January 1, 2003, we adopted SFAS No. 143, *Accounting for Asset Retirement Obligations*. This standard required that we record a liability for retirement and removal costs of long-lived assets used in our businesses. In 2003, we recorded a charge as a cumulative effect of an accounting change of approximately $9 million, net of income taxes related to its adoption.

New Accounting Pronouncement Not Yet Adopted

In September 2004, the SEC issued Staff Accounting Bulletin No. 106. This pronouncement will require companies that use the full cost method for accounting for their oil and gas producing activities to include an estimate of future asset retirement costs to be incurred as a result of future development activities on proved reserves in their calculation of depreciation, depletion and amortization. It will also require these companies to exclude future cash outflows associated with settling asset retirement liabilities from their full cost ceiling test calculation. Finally, this standard will require disclosure of the impact of a company's asset retirement obligations on its oil and gas producing activities, ceiling test calculations and depreciation, depletion and amortization calculations. We will adopt the provisions of this pronouncement in the first quarter of 2005 and are currently evaluating its impact, if any, on our consolidated financial statements.

3. Acquisitions and Consolidations

Chaparral Investors, L.L.C. As discussed more completely in our 2003 Annual Report on Form 10-K, we acquired Chaparral in a series of transactions (also referred to as a step acquisition). We reflected Chaparral's results of operations in our income statement as though we acquired it on January 1, 2003. Although this did not change our reported net income for the first quarter of 2003, it did impact the individual components of our income statement by increasing our revenues by $76 million, operating expenses by $80 million, earnings (losses) from unconsolidated affiliates by $55 million, interest expense by $67 million and decreasing distributions on preferred interests in subsidiaries by $18 million and other income by $2 million.

During the first quarter of 2003, as a result of an additional investment in Limestone Electron Trust (Limestone), coupled with a number of developments including a general decline in power prices, declines in our credit ratings as well as those of our counterparties, adverse developments at several of Chaparral's projects, our announced exit from the power contract restructuring business and generally weaker economic conditions in the unregulated power industry, we determined that the fair value of Chaparral (based on its discounted expected net cash flows) was less than our carrying value of the investment. As a result, we recorded an impairment of $207 million on Chaparral, before income taxes, during the first quarter of 2003.

Gemstone. As discussed more completely in our 2003 Annual Report on Form 10-K, we acquired all of the outstanding third party interests in Gemstone for approximately $50 million in April 2003. The results of Gemstone's operations have been included in our consolidated financial statements beginning April 1, 2003. Had the acquisition been effective January 1, 2003, our revenues, operating income, and net income for the quarter ended March 31, 2003 would not have been significantly different, and basic and diluted earnings per share would have been unaffected.

4. Divestitures

Sales of Assets and Investments

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

Significant Assets and Investments Sold	Completed Through June 30, 2004	Completed After June 30, 2004 or Announced to Date[1]	Total
		(In millions)	
Regulated			
Pipelines	$ 50	$ 4	$ 54
• Australia pipelines[2]			
• Aircraft[2]			
• Interest in gathering systems[3]			
Unregulated			
Production	—	24	24
• Brazilian exploration and production assets[3]			
Power	99	777	876
• 25 domestic power plants under contract[4]			
• Utility Contract Funding (UCF)[2]			
• Mohawk River Funding IV[2]			
• Bastrop Company equity investment[2]			
• 5 other domestic power plants and turbines[3]			
Field Services	—	1,026	1,026
• General partnership interest, common units and Series C units of GulfTerra[3]			
• South Texas processing plants[3]			
Other			
Corporate	16	—	16
• Aircraft[2]			
Total continuing	165	1,831	1,996
Discontinued	1,261	34	1,295
• Natural gas and oil production properties in Canada[2]			
• Aruba and Eagle Point refineries and other petroleum assets[2]			
• Remaining Indonesian and Canadian production assets[3]			
Total	$1,426	$1,865	$3,291

(1) Sales that have not been completed are estimates, subject to customary regulatory approvals, final negotiations and other conditions.
(2) These sales were completed as of June 30, 2004.
(3) These sales were or will be completed after June 30, 2004.
(4) The sales of 22 of these plants were completed after June 30, 2004.

Significant Assets and Investments Sold	Proceeds (In millions)
As of June 30, 2003	
Regulated	
Pipelines	$ 63
• Panhandle gathering system located in Texas	
• 2.1 percent interest in Alliance pipeline and related assets	
• Helium processing operations in Oklahoma	
• Table Rock sulfur extraction facility	
Unregulated	
Production	657
• Natural gas and oil properties in New Mexico, Oklahoma and the Gulf of Mexico	
Power	289
• 50 percent interest in CE Generation L.L.C. power investment	
• Mt. Carmel power plant	
• Interest in Kladno power project	
• CAPSA/CAPEX investments in Argentina	
Field Services	153
• Gathering systems located in Wyoming	
• Midstream assets in the north Louisiana and Mid-Continent regions	
Other	
Corporate	68
• Aircraft	
• Enerplus Global Energy Management Company and its financial operations	
Total continuing	1,230[1]
Discontinued	581
• Corpus Christi refinery	
• Florida petroleum terminals and tug and barge operations	
• Louisiana lease crude business	
• Coal reserves and properties in West Virginia, Virginia and Kentucky	
• Natural gas and oil production properties in Canada	
Total	$1,811

[1] Proceeds include costs incurred in preparing assets for disposal and exclude returns of invested capital and cash transferred with the assets sold. These items increased our sales proceeds by $52 million for the six months ended June 30, 2003.

See Notes 6 and 16 for a discussion of gains, losses and asset impairments related to the sales above.

Under SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, we classify assets being disposed of as held for sale or, if appropriate, discontinued operations if they have received appropriate approvals by our management or Board of Directors and have met other criteria. The following table details the items that have been reflected as current assets and liabilities held for sale in our balance sheets as of June 30, 2004 and December 31, 2003.

	June 30, 2004	December 31, 2003
	(In millions)	
Assets Held for Sale		
Current assets	$ 54	$ 46
Investments in unconsolidated affiliates	472	480
Property, plant and equipment, net	448	477
Other assets	142	136
Total assets	$1,116	$1,139
Current liabilities	$ 59	$ 54
Long-term debt, less current maturities	165	169
Other liabilities	11	13
Total liabilities	$ 235	$ 236

In August 2004, our Board of Directors authorized the sale of our Indian Springs natural gas gathering and processing assets in our Field Services segment, which consisted primarily of property, plant and equipment. We will classify these assets as held for sale and expect to incur an impairment charge of approximately $13 million related to these assets in the third quarter of 2004 based on expected sales proceeds of approximately $74 million.

Discontinued Operations

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 November 2004, we have completed the sale of all of our Canadian operations and substantially all of our operations in Indonesia for total proceeds of approximately $389 million. During the six months ended June 30, 2004, we recognized approximately $93 million in asset impairments and losses on these sales. We expect to complete the sale of the remainder of these properties in 2004 and early 2005.

Petroleum Markets. During the first quarter of 2003, our Board of Directors approved the sales of our Eagle Point refinery, our asphalt business, our Florida terminal, tug and barge business and our lease crude operations. In June 2003, our Board of Directors authorized the sale of our remaining petroleum markets operations, including our Aruba refinery, our Unilube blending operations, our domestic and international terminalling facilities and our petrochemical and chemical plants. Based on our intent to dispose of these operations, we were required to adjust these assets to their estimated fair value. As a result, we recognized a pre-tax impairment charge of approximately $987 million during the second quarter of 2003 related to our petroleum and chemical assets. Our second quarter 2003 charge was in addition to the $350 million pre-tax impairment charge recognized during the first quarter of 2003 when we announced our intent to sell our Eagle Point refinery and several of our chemical assets. These impairments were based on a comparison of the carrying value of these assets to their estimated fair value, less selling costs. We also recorded realized gains of approximately $52 million in the first six months of 2003 from the sale of our Corpus Christi refinery and Florida terminalling and marine assets.

In the first and second quarters of 2004, we completed the sales of our Aruba and Eagle Point refineries for $880 million and used a portion of the proceeds to repay $370 million of debt associated with the Aruba refinery. In addition, in the first quarter of 2004, we reclassified our petroleum ship charter operations from discontinued operations to continuing operations in our financial statements based on our decision to retain these operations. Our financial statements for all periods presented reflect this change.

Coal Mining. In 2002, our Board of Directors authorized the sale of our coal mining operations. These operations consisted of fifteen active underground and two surface mines located in Kentucky, Virginia and West Virginia. The sale of these operations was completed in 2003 for $92 million in cash and $24 million in notes receivable, which were settled in the second quarter of 2004. We did not record a significant gain or loss on these sales.

The petroleum markets, coal mining and our other international natural gas and oil production operations discussed above, are classified as discontinued operations in our financial statements for all of the historical periods presented. All of the assets and liabilities of these discontinued businesses are classified as current assets and liabilities as of June 30, 2004. The summarized financial results and financial position data of our discontinued operations were as follows:

	Petroleum Markets	International Natural Gas and Oil Production Operations	Coal Mining	Total
		(In millions)		
Operating Results Data				
Quarter Ended June 30, 2004				
Revenues	$ 54	$ 1	$ —	$ 55
Costs and expenses	(77)	(3)	—	(80)
Gain on long-lived assets	4	—	—	4
Other income	2	—	—	2
Loss before income taxes	(17)	(2)	—	(19)
Income taxes	(3)	13	—	10
Loss from discontinued operations, net of income taxes	$ (14)	$ (15)	$ —	$ (29)
Quarter Ended June 30, 2003				
Revenues	$ 1,511	$ 20	$ —	$ 1,531
Costs and expenses	(1,612)	(33)	—	(1,645)
Loss on long-lived assets	(990)	(5)	—	(995)
Other expense	(21)	—	—	(21)
Interest and debt expense	(4)	—	—	(4)
Loss before income taxes	(1,116)	(18)	—	(1,134)
Income taxes	(198)	3	—	(195)
Loss from discontinued operations, net of income taxes	$ (918)	$ (21)	$ —	$ (939)

	Petroleum Markets	International Natural Gas and Oil Production Operations	Coal Mining	Total
		(In millions)		
Six Months Ended June 30, 2004				
Revenues	$ 693	$ 28	$ —	$ 721
Costs and expenses	(730)	(47)	—	(777)
Loss on long-lived assets	(38)	(93)	—	(131)
Interest and debt expense	(3)	1	—	(2)
Loss before income taxes	(78)	(111)	—	(189)
Income taxes	(9)	(42)	—	(51)
Loss from discontinued operations, net of income taxes	$ (69)	$ (69)	$ —	$ (138)
Six Months Ended June 30, 2003				
Revenues	$ 3,679	$ 46	$ 27	$ 3,752
Costs and expenses	(3,744)	(47)	(21)	(3,812)
Loss on long-lived assets	(1,286)	(14)	(3)	(1,303)
Other income (expense)	(14)	—	1	(13)
Interest and debt expense	(4)	1	—	(3)
Income (loss) before income taxes	(1,369)	(14)	4	(1,379)
Income taxes	(226)	—	1	(225)
Income (loss) from discontinued operations, net of income taxes	$(1,143)	$ (14)	$ 3	$(1,154)

	Petroleum Markets	International Natural Gas and Oil Production Operations	Total
		(In millions)	
Financial Position Data			
June 30, 2004			
Assets of discontinued operations			
Accounts and notes receivable	$ 60	$ 11	$ 71
Inventory	7	—	7
Other current assets	7	2	9
Property, plant and equipment, net	22	33	55
Other non-current assets	23	—	23
Total assets	$ 119	$ 46	$ 165
Liabilities of discontinued operations			
Accounts payable	$ 12	$ 1	$ 13
Other current liabilities	14	—	14
Other non-current liabilities	6	—	6
Total liabilities	$ 32	$ 1	$ 33

	Petroleum Markets	International Natural Gas and Oil Production Operations	Total
		(In millions)	
December 31, 2003			
Assets of discontinued operations			
Accounts and notes receivable	$ 259	$ 22	$ 281
Inventory	385	3	388
Other current assets	131	8	139
Property, plant and equipment, net	521	399	920
Other non-current assets	70	6	76
Total assets	$1,366	$438	$1,804
Liabilities of discontinued operations			
Accounts payable	$ 172	$ 39	$ 211
Other current liabilities	86	—	86
Long-term debt	374	—	374
Other non-current liabilities	26	3	29
Total liabilities	$ 658	$ 42	$ 700

5. Restructuring Costs

As a result of actions taken in 2003 and 2004, we incurred organizational restructuring costs included in our operation and maintenance expense. By segment, these charges were as follows for the six months ended June 30:

	Regulated	Unregulated					
	Pipelines	Production	Marketing and Trading	Power	Field Services	Corporate	Total
			(In millions)				
2004							
Employee severance, retention and transition costs	$ 5	$11	$ 2	$ 3	$ 1	$11	$ 33
2003							
Employee severance, retention and transition costs	$ 1	$ 4	$ 4	$ 4	$ 3	$40	$ 56
Contract termination costs	—	—	—	—	—	44	44
	$ 1	$ 4	$ 4	$ 4	$ 3	$84	$100

Our 2004 restructuring costs consisted of employee severance costs which included severance payments and costs for pension benefits settled and curtailed under existing benefit plans. During the quarter ended June 30, 2004, we incurred $6 million in severance and related charges in our Pipelines and Production segments and in our corporate activities. As of September 30, 2004, substantially all of the employee severance, retention and transition costs had been paid.

Our 2003 restructuring costs were incurred as part of our ongoing liquidity enhancement and cost reduction efforts. Employee severance costs included severance payments and costs for pension benefits settled and curtailed under existing benefit plans. During the quarter ended June 30, 2003, we incurred $31 million in severance and related charges across all of our segments. The contract termination costs were recorded in the first quarter of 2003 and consisted of $44 million related to amounts paid for canceling or restructuring our obligations for chartering ships to transport liquefied natural gas (LNG) from supply areas to domestic and international market centers.

Office Relocation and Consolidation

In May 2004, we began consolidating our Houston-based operations into one location. We anticipate the consolidation will be substantially complete by the end of 2004. As a result, we will establish an accrual to record a liability for our obligations under the terms of the vacated leases in the period that the space is available for subleasing. We currently lease approximately 912,000 square feet of office space in the buildings we are vacating under various leases with terms that expire in 2004 through 2014. We estimate the total accrual for our liability will be approximately $80 million to $100 million. At the time the decision was made to consolidate our Houston-based operations, approximately 26,000 square feet was vacant and available for subleasing at which time we accrued an obligation of approximately $1 million. During the third quarter of 2004, we vacated approximately 211,000 square feet and recorded a liability of approximately $30 million. In addition, we subleased approximately 125,000 square feet in the third quarter of 2004. Approximately $3 million in actual moving expenses related to the relocation will be expensed in the period that they are incurred. These amounts will be reflected in our corporate activities.

6. Loss on Long-Lived Assets

Our loss on long-lived assets consists of realized gains and losses on sales of long-lived assets and impairments of long-lived assets, goodwill and other intangible assets that are a part of our continuing operations. During each of the periods ended June 30, our loss on long-lived assets was as follows:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2004	2003	2004	2003
	(In millions)			
Net realized gain	$(6)	$(21)	$(14)	$(16)
Asset impairments	23	416	253	425
Loss on long-lived assets	$17	$395	$239	$409

Net Realized Gain

Our 2004 net realized gain was primarily related to an $8 million gain on aircraft sales associated with our Corporate activities. Our 2003 net realized gain was primarily related to a $14 million gain on the sale of our north Louisiana and Mid-Continent midstream assets in our Field Services segment, a $6 million gain on the Table Rock sulfur extraction facility in our Pipelines segment, and a $5 million gain on the sale of non-full cost pool assets in our Production segment. Partially offsetting these gains were $8 million of losses related to the sales of assets associated with our corporate activities in 2003.

Asset Impairments

Our 2004 asset impairments primarily occurred in our Power segment, which included a $135 million impairment related to our Manaus and Rio Negro power plants in Brazil and a $98 million impairment related to the sale of our subsidiary, UCF, which owns a restructured power contract. The impairments in Brazil were primarily due to events in the first quarter of 2004 that may make it difficult to extend the plants' power sales agreements that expire in 2005 and 2006. See Note 12 for a further discussion of these matters. Our Power segment also recorded $10 million of impairments primarily in the second quarter of 2004 on our domestic power plants to adjust the carrying value of these plants to their expected sales price. We recorded $7 million of impairments in the second quarter of 2004 in our Field Services segment, primarily related to the abandonment of miscellaneous assets that will no longer be used after the merger between GulfTerra and Enterprise. See Note 16 for a further discussion of the merger.

Our 2003 impairment charges related to our telecommunications and LNG operations, both included in our corporate activities. Our telecommunications operations recorded charges of $396 million, which included a $269 million impairment charge (including a $163 million writedown of goodwill) related to our investment in the wholesale metropolitan transport services, primarily in Texas and an impairment of our Lakeside Technology Center facility of $127 million based on probability-weighted scenarios of what the asset could be sold for in the current market. We also recorded a $31 million impairment on our LNG assets related to our plan to reduce our involvement in that business.

7. Income Taxes

Income taxes included in our income (loss) from continuing operations for the periods ended June 30, 2004 and 2003 were as follows:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2004	2003	2004	2003
	(In millions, except rates)			
Income taxes	$37	$(410)	$ 47	$(513)
Effective tax rate	45%	58%	(940)%	50%

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 the first six months of 2004, our overall effective tax rate on continuing operations was significantly different than the statutory rate due primarily to impairments of certain of our foreign investments for which there is no corresponding U.S. federal income tax benefit combined with a loss before income taxes. This resulted in an overall tax expense for a period in which there was also a pre-tax loss.

For the year ended December 31, 2004, our effective tax rate will be significantly different from the statutory rate of 35 percent because of the completion of the merger between GulfTerra and Enterprise in September 2004. The sale of our interests in GulfTerra associated with the merger will result in a significant tax gain (versus a much lower book gain) and significant tax expense due to the non-deductibility of goodwill written off as a result of the transaction. We believe the impact of this non-deductible goodwill will increase our tax expense (or reduce our tax benefit) by approximately $139 million. See Note 16 for a further discussion of the merger and related transactions.

Proposed tax legislation is being considered in Congress which would disallow deductions for certain settlements made to or on behalf of governmental entities. If enacted, this tax legislation could impact the deductibility of the Western Energy Settlement and could result in a write-off of some or all of the associated tax assets. In such event, our tax expense would increase. Our total tax assets related to the Western Energy Settlement were approximately $400 million as of June 30, 2004.

8. Earnings Per Share

Our basic and diluted income (loss) per share were as follows for the periods ended June 30:

	Quarter Ended June 30, 2004	Quarter Ended June 30, 2003	Six Months Ended June 30, 2004	Six Months Ended June 30, 2003
	(In millions, except per common share amounts)			
Income (loss) from continuing operations	$ 45	$ (297)	$ (52)	$ (504)
Discontinued operations, net of income taxes	(29)	(939)	(138)	(1,154)
Cumulative effect of accounting changes, net of income taxes	—	—	—	(9)
Net income (loss)	$ 16	$(1,236)	$ (190)	$(1,667)
Average common shares outstanding	639	596	639	595
Income (loss) per common share				
Income (loss) from continuing operations	$ 0.07	$ (0.50)	$(0.08)	$ (0.84)
Discontinued operations, net of income taxes	(0.04)	(1.57)	(0.22)	(1.94)
Cumulative effect of accounting changes, net of income taxes	—	—	—	(0.02)
Net income (loss) per common share	$ 0.03	$ (2.07)	$(0.30)	$ (2.80)

For the quarters and six months ended June 30, 2004 and June 30, 2003, there were 16 million of potentially dilutive securities excluded from the determination of average common shares outstanding due to their antidilutive effect on income (loss) per common share. The excluded securities included stock options, trust preferred securities and convertible debentures.

9. Price Risk Management Activities

The following table summarizes the carrying value of the derivatives used in our price risk management activities as of June 30, 2004 and December 31, 2003. 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.

	June 30, 2004	December 31, 2003
	(In millions)	
Net assets (liabilities)		
Derivatives designated as hedges	$ (32)	$ (31)
Derivatives from power contract restructuring activities	946	1,925[1]
Other commodity-based derivative contracts	(626)	(488)
Total commodity-based derivatives	288	1,406
Interest rate and foreign currency hedging derivatives[2]	75	123
Net assets from price risk management activities[3]	$ 363	$1,529

(1) Includes $942 million of derivative contracts sold in connection with the sales of Utility Contract Funding and Mohawk River Funding IV in 2004. See Note 6 for a discussion of the net losses related to these sales.

(2) During the six months ended June 30, 2004, we entered into new cross currency hedge transactions that convert €75 million of our fixed rate Euro-denominated debt into $91 million of floating rate debt. After June 30, 2004, we entered into other cross currency hedge transactions that convert another €25 million of fixed rate debt into $30 million of floating rate debt.

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

10. Inventory

We have the following inventory recorded on our balance sheets:

	June 30, 2004	December 31, 2003
	(In millions)	
Materials and supplies and other	$131	$145
Natural gas liquids and natural gas in storage	26	36
Total current inventory	$157	$181

11. Debt, Other Financing Obligations and Other Credit Facilities

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

	June 30, 2004	December 31, 2003
	(In millions)	
Current maturities of long-term debt and other financing obligations	$ 1,522	$ 1,401
Short-term financing obligations	52	56
Total short-term financing obligations	$ 1,574	$ 1,457
Long-term financing obligations	$18,259	$20,275

Long-Term Financing Obligations

From January 1, 2004 through the date of this filing, we had the following changes in our long-term financing obligations:

Company	Type	Interest Rate	Principal	Net Increase/ Reduction in Debt	Due Date
			(In millions)		
Issuances and other increases					
Macae	Non-recourse note	LIBOR + 4.25%	$ 50	$ 50	2007
Blue Lake Gas Storage[1]	Non-recourse term loan	LIBOR + 1.2%	14	14	2006
Increases through June 30, 2004			64	64	
El Paso[2]	Note	6.50%	213	213	2005
Increases through date of filing			$ 277	$ 277	
Repayments and Other Retirements					
El Paso CGP	Note	LIBOR + 3.5%	$ 200	$ 200	
El Paso	Revolver	LIBOR + 3.5%	250	250	
Gemstone	Notes	7.71%	181	181	
El Paso CGP	Note	6.2%	190	190	
Mohawk River Funding IV[3]	Non-recourse note	7.75%	72	72	
Utility Contract Funding[3]	Non-recourse senior notes	7.944%	815	815	
Other	Long-term debt	Various	203	203	
Decreases through June 30, 2004			1,911	1,911	
El Paso	Revolver	LIBOR + 3.5%	600	600	
Gemstone	Notes	7.71%	769	769	
Lakeside	Note	LIBOR + 3.5%	42	42	
El Paso CGP	Notes	10.25%	38	38	
Other	Long-term debt	Various	63	63	
Decreases through date of filing			$3,423	$3,423	

(1) This debt was consolidated as a result of adopting FIN No. 46 (see Note 2).

(2) In October 2004, we entered into an agreement, effective August 2004, with two affiliates of Enron that liquidates two of our derivative swap agreements in exchange for approximately $213 million of 6.5%, one year notes. The transaction was approved by the bankruptcy court in November 2004. As of June 30, 2004, the balance of these swaps was a liability of $234 million, which is reflected in other current and other non-current liabilities in our balance sheet.

(3) This debt was eliminated when we sold our interests in Mohawk River Funding IV and UCF.

Credit Facilities

In November 2004, we entered into an agreement with a group of lenders for an aggregate of $3 billion in financings that will become available to us upon the filing of this Form 10-Q. These financings will replace our existing revolving credit facility, and will provide approximately $220 million in net additional borrowing availability (after repayment of our Lakeside Technology Center obligation of approximately $229 million, fees, and other obligations), as compared to the borrowing availability under our existing credit facility. The new credit agreement is comprised of a $1.25 billion term loan, a $1 billion revolving credit facility, and a $750 million funded letter of credit facility. Certain of our subsidiaries, EPNG, TGP, ANR, and CIG will also continue to be borrowers under the new credit agreement. Additionally, El Paso and certain of its subsidiaries have guaranteed borrowings under the new credit agreement which is collateralized by our interests in EPNG, TGP, ANR, CIG, WIC, ANR Storage Company, and Southern Gas Storage Company.

Under the term loan we will borrow $1.25 billion at LIBOR plus 2.75 percent, which will mature in November 2009, and will be repaid in increments of $5 million per quarter with the unpaid balance due at maturity. Under the new revolving credit facility, which matures in November 2007, we can borrow funds at LIBOR plus 2.75 percent, or issue letters of credit at 2.75 percent plus a fee of 0.25 percent of the amount issued. We will pay an annual commitment fee of 0.75 percent on any unused capacity under the revolving credit facility. As discussed below, we will use a portion of the new revolving credit facility to support existing letters of credit under our current credit facility. The remaining amount under this $1 billion revolving credit facility will initially be undrawn.

Upon closing of the new credit agreement, certain lenders will fund a $750 million letter of credit facility that will provide us the ability to issue letters of credit or borrow any unused capacity under the facility as loans with a maturity in November 2009. We will pay LIBOR plus 2.75 percent on any amounts borrowed under the facility, and 2.85 percent on letters of credit and unborrowed funds. We will initially use this letter of credit facility to support currently outstanding letters of credit.

The availability of borrowings under the new credit agreement and other borrowing agreements is subject to various conditions described below, which we currently meet. These conditions include compliance with the financial covenants and ratios required by those agreements, absence of default under the agreements, and continued accuracy of the representations and warranties contained in the agreements.

Restrictive Covenants

Our restrictive covenants includes restrictions on debt levels, restrictions on liens securing debt and guarantees, restrictions on mergers and on the sales of assets, capitalization requirements, dividend restrictions and cross default and cross-acceleration provisions. A breach of any of these covenants could result in acceleration of our debt and other financial obligations and that of our subsidiaries. Under our new credit agreement the significant debt covenants and cross defaults are:

(a) the ratio of Debt to Consolidated EBITDA, each as defined in the new credit agreement, shall not exceed 6.50 to 1 at any time prior to September 30, 2005, 6.25 to 1 at any time on or after September 30, 2005 and prior to June 30, 2006, and 6.00 to 1 at any time on or after June 30, 2006 until maturity;

(b) the ratio of Consolidated EBITDA, as defined in the new credit agreement, to interest expense and dividends paid shall not be less than 1.60 to 1 prior to March 31, 2006, 1.75 to 1 on or after March 31, 2006 and prior to March 31, 2007, and 1.80 to 1 on or after March 31, 2007 until maturity;

(c) EPNG, TGP, ANR, and CIG cannot incur incremental debt if the incurrence of this incremental Debt would cause their Debt to Consolidated EBITDA ratio, each as defined in the new credit agreement, for that particular company to exceed 5 to 1;

(d) the proceeds from the issuance of Debt by our pipeline company borrowers can only be used for maintenance and expansion capital expenditures or investments in other FERC-regulated assets, to fund working capital requirements, or to refinance existing debt; and

(e) the occurrence of an event of default and after the expiration of any applicable grace period, with respect to Debt in an aggregate principal amount of $200 million or more.

In addition to the above restrictions and default provisions, we and/or our subsidiaries are subject to a number of additional restrictions and covenants. These restrictions and covenants include limitations of additional debt at some of our subsidiaries; limitations on the use of proceeds from borrowing at some of our subsidiaries; limitations, in some cases, on transactions with our affiliates; limitations on the occurrence of liens; potential limitations on the abilities of some of our subsidiaries to declare and pay dividends and potential limitations on some of our subsidiaries to participate in our cash management program, and limitations on our ability to prepay debt.

Letters of Credit

We enter into letters of credit in the ordinary course of our operating activities. As of June 30, 2004, we had outstanding letters of credit of approximately $1.2 billion, of which $1.1 billion was outstanding under our existing revolving credit facility and $62 million was supported with cash collateral. Included in this amount were $0.6 billion of letters of credit securing our recorded obligations related to price risk management activities. Prior to the closing of our new credit agreement, we will have approximately $1.2 billion of letters of credit. We will use the new $750 million letter of credit facility and approximately $0.4 billion of the new $1.0 billion revolving credit facility to support these issued letters of credit.

12. Commitments and Contingencies

Legal Proceedings

Western Energy Settlement. In June 2004, our master settlement agreement, along with other separate settlement agreements, became effective with a number of public and private claimants, including the states of California, Washington, Oregon and Nevada to resolve the principal litigation, claims and regulatory proceedings arising out of the sale or delivery of natural gas and/or electricity to the western U.S. (the Western Energy Settlement). As part of the Western Energy Settlement, we agreed, among other things, to make various cash payments and modify an existing power supply contract.

We also entered into a Joint Settlement Agreement or JSA where we agreed to provide structural relief to the settling parties. In the JSA, we agreed to do the following:

- Subject to the conditions in the settlement; (1) make 3.29 Bcf/d of primary firm pipeline capacity on our EPNG system available to California delivery points during a five year period from the date of settlement, but only if shippers sign firm contracts for 3.29 Bcf/d of capacity with California delivery points; (2) maintain facilities sufficient to deliver 3.29 Bcf/d to the California delivery points; and (3) not add any firm incremental load to our EPNG system that would prevent it from satisfying its obligation to provide this capacity;
- Construct a new 320 MMcf/d, Line 2000 Power-Up expansion project and forego recovery of the cost of service of this expansion until EPNG's next rate case before the FERC;
- Clarify the rights of Northern California shippers to recall some of EPNG's system capacity (Block II capacity) to serve markets in PG&E's service area; and
- With limited exceptions, bar any of our affiliated companies from obtaining additional firm capacity on our EPNG pipeline system during a five year period from the effective date of the settlement.

In June 2003, we filed the JSA described above 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 have appealed the FERC's ruling to the U.S. Court of Appeals for the District of Columbia.

During the fourth quarter of 2002, we recorded an $899 million pretax charge related to the Western Energy Settlement. In the second quarter of 2003, we recorded an additional pretax charge of $104 million based upon reaching definitive settlement agreements. Charges and expenses associated with the Western Energy Settlement are included in operations and maintenance expense in our consolidated statements of income. In June 2004, the settlement became effective and $602 million was released to the settling parties. This amount is shown as a reduction of our cash flows from operations in the second quarter of 2004. Of the amount released, $568 million has been previously held in an escrow account pending final approval of the settlement. The release of these restricted funds is included as an increase in our cash flows from investing activities. Our remaining obligation as of June 30, 2004 under the Western Energy Settlement consists of the discounted 20-year cash payment obligation of $398 million and a price reduction under a power supply contract, which is included in our price risk management activities. In connection with the Western Energy Settlement, we provided collateral in the form of natural gas and oil properties to secure our remaining cash payment obligation. The initial collateral requirement was approximately $592 million and will be reduced as payments under our 20 year obligation are made. For an issue regarding the potential tax deductibility of our Western Energy Settlement charges, see Note 7.

We are also a defendant in a number of additional lawsuits, pending in several Western states, relating to various aspects of the 2000-2001 Western energy crisis. We do not believe these additional lawsuits, either individually or in the aggregate, will have a material impact on us.

CPUC Complaint Proceeding Docket No. RP00-241-000. In April 2000, the CPUC filed a complaint under Section 5 of the Natural Gas Act (NGA) with FERC alleging that EPNG's sale of approximately 1.2 Bcf of capacity to its affiliate raised issues of market power and was a violation of the FERC's marketing regulations and asked that the contracts be voided. In the spring and summer of 2001, hearings were held before an ALJ to address the market power issue and the affiliate issue. In November 2003, the FERC approved the JSA, which is part of the Western Energy Settlement and vacated the ALJ's initial decisions. That decision was upheld by the FERC in a rehearing order issued in March 2004. In April 2004, certain shippers appealed both FERC orders on this matter to the U.S. Court of Appeals for the District of Columbia Circuit.

Shareholder Class Action Suits. Beginning in July 2002, twelve purported shareholder class action lawsuits alleging violations of federal securities laws have been filed against us and several of our former officers. Eleven of these lawsuits are now consolidated in federal court in Houston before a single judge. The twelfth lawsuit, filed in the Southern District of New York, was dismissed in light of similar claims being asserted in the consolidated suits in Houston. The lawsuits generally challenge the accuracy or completeness of press releases and other public statements made during 2001 and 2002. Two shareholder derivative actions have also been filed which generally allege the same claims as those made in the consolidated shareholder class action lawsuits. One, which was filed in federal court in Houston in August 2002, has been consolidated with the shareholder class actions pending in Houston, and has been stayed. The second shareholder derivative lawsuit, filed in Delaware State Court in October 2002, generally alleges the same claims as those made in the consolidated shareholder class action lawsuit and also has been stayed. Two other shareholder derivative lawsuits are now consolidated in state court in Houston. Both generally allege that manipulation of California gas supply and gas prices exposed us to claims of antitrust conspiracy, FERC penalties and erosion of share value.

Beginning in February 2004, seventeen purported shareholder class action lawsuits alleging violations of federal securities laws were filed against us and several individuals in federal court in Houston. The lawsuits generally allege that our reporting of natural gas and oil reserves was materially false and misleading. Each of these lawsuits recently has been consolidated into the shareholder lawsuits described in the immediately preceding paragraph. An amended complaint in this consolidated securities lawsuit was filed in July 2004.

In September 2004, a new derivative lawsuit was filed in federal court in Houston against certain of El Paso's current and former directors and officers. The claims in this new derivative lawsuit are for the most part the same claims made in the July 2004 consolidated amended complaint in the securities lawsuit. The one distinction is that the new derivative lawsuit includes a claim for compensation disgorgement against certain of the individually named defendants under the Sarbanes-Oxley Act of 2002.

Our costs and exposures in these lawsuits are not currently determinable. We are currently evaluating each of these cases as to their merits, our defenses, their possible settlement and potential insurance recoveries.

ERISA Class Action Suit. In December 2002, a purported class action lawsuit was filed in federal court in Houston 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. Our costs and legal exposure related to this lawsuit are not currently determinable; however, we believe this matter will be covered by insurance.

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. 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. EPM and approximately 27 other energy companies remain in the litigation. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

Grynberg. A number of our subsidiaries were named defendants in actions filed in 1997 brought by Jack Grynberg on behalf of the U.S. Government under the False Claims Act. Generally, these complaints allege an industry-wide conspiracy to underreport the heating value as well as the volumes of the natural gas produced from federal and Native American lands, which deprived the U.S. Government of royalties. The plaintiff in this case seeks royalties that he contends the government should have received had the volume and heating value been differently measured, analyzed, calculated and reported, together with interest, treble damages, civil penalties, expenses and future injunctive relief to require the defendants to adopt allegedly appropriate gas measurement practices. No monetary relief has been specified in this case. These matters have been consolidated for pretrial purposes (In re: Natural Gas Royalties *Qui Tam* Litigation, U.S. District Court for the District of Wyoming, filed June 1997). Discovery is proceeding. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

Will Price (formerly Quinque). A number of our subsidiaries 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 has since been filed as to the heating content claims. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

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 our subsidiaries are currently one of several defendants in over 50 such lawsuits nationwide, which, with the exception of two lawsuits recently filed in a California state court, 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 generally seek remediation of their groundwater, prevention of future contamination, a variety of compensatory damages, punitive damages, attorney's fees, and court costs. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

Government Investigations

Power Restructuring. In October 2003, we announced that the SEC had authorized the staff of the Fort Worth Regional Office to conduct an investigation of certain aspects of our periodic reports filed with the SEC. The investigation appears to be focused principally on our power plant contract restructurings and the related disclosures and accounting treatment for the restructured power contracts, including in particular the Eagle Point restructuring transaction completed in 2002. We are cooperating with the SEC investigation.

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 are also cooperating with the U.S. Attorney regarding an investigation of specific transactions executed in connection with hedges of our natural gas and oil production.

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. We are cooperating with the SEC's and the U.S. Attorney's investigations of this matter.

CFTC Investigation. In April 2004, our affiliates elected to voluntarily cooperate with the CFTC in connection with the CFTC's industry-wide investigation of activities affecting the price of natural gas in the fall of 2003. Specifically, our affiliates provided information relating to storage reports provided to the Energy Information Administration for the period of October 2003 through December 2003. In August 2004, the CFTC announced they had completed the investigation and found no evidence of wrongdoing.

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 relating to transactions in oil of Iraqi originating 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 Oil for Food Program. We have also received an inquiry from the United States Senate's Permanent Subcommittee of Investigations related to a specific transaction in 2000.

In September 2004, the Special Advisor to the Director of Central Intelligence issued a report on the Iraqi regime, including the Oil for Food Program. In part, the report found that the Iraqi regime earned kick backs or surcharges associated with the Oil for Food Program. The report did not name U.S. companies or individuals for privacy reasons, but according to various news reports congressional sources have identified The Coastal Corporation and the former chairman and CEO of Coastal, among others, as having purchased Iraqi crude during the period when allegedly improper surcharges were assessed by Iraq.

We are cooperating with the U.S. Attorney's and the Senate Subcommittee's investigations of this matter.

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 issued a Notice of Probable Violation and Proposed Civil Penalty to EPNG. The Notice alleged five violations of DOT regulations, proposed fines totaling $2.5 million and proposed corrective actions. EPNG has fully accrued for these fines. In October 2001, EPNG filed a response with the Office of Pipeline Safety disputing each of the alleged violations. In December 2003, the matter was referred to the Department of Justice.

After a public hearing conducted by the National Transportation Safety Board (NTSB) on its investigation into the Carlsbad rupture, the NTSB published its final report in April 2003. The NTSB stated that it had determined that the probable cause of the August 2000 rupture was a significant reduction in pipe wall thickness due to severe internal corrosion, which occurred because EPNG's corrosion control program "failed to prevent, detect, or control internal corrosion" in the pipeline. The NTSB also determined that ineffective federal preaccident inspections contributed to the accident by not identifying deficiencies in EPNG's internal corrosion control program.

In November 2002, EPNG received a federal grand jury subpoena for documents related to the Carlsbad rupture and cooperated fully in responding to the subpoena. That subpoena has since expired. In December 2003 and January 2004, eight current and former employees were served with testimonial subpoenas issued by the grand jury. Six individuals testified in March 2004. In April 2004, we and EPNG received a new federal grand jury subpoena requesting additional documents. We have responded fully to this subpoena. Two additional employees testified before the grand jury in June 2004.

A number of personal injury and wrongful death lawsuits were filed against EPNG in connection with the rupture. All of these lawsuits have been settled, with settlement payments fully covered by insurance. In connection with the settlement of the cases, EPNG contributed $10 million to a charitable foundation as a memorial to the families involved. The contribution was not covered by insurance.

Parties to four of the settled lawsuits have since filed an additional lawsuit titled *Diane Heady et al. v. EPEC and EPNG* in Harris County, Texas in November 2002, seeking additional sums based upon their interpretation of earlier settlement agreements. This matter has been settled and dismissed. In addition, a lawsuit entitled *Baldonado et. al. v. EPNG* was filed in June 2003 in state court in Eddy County, New Mexico on behalf of 23 firemen and EMS personnel who responded to the fire and who allegedly have suffered psychological trauma. This case was dismissed by the trial court. The appeals court initially issued a notice dismissing all claims. This decision was appealed and the appeals court has agreed to hear this matter. Briefs will be filed by the end of this year. Our costs and legal exposure related to the *Baldonado* lawsuit are not currently determinable, however we believe this matter will be fully covered by insurance.

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.

For each of our outstanding legal matters, we evaluate the merits of the case, our exposure to the matter, possible legal or settlement strategies and the likelihood of an unfavorable outcome. If we determine that an unfavorable outcome is probable and can be estimated, we establish the necessary accruals. As 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 current reserves are adequate. As of June 30, 2004, we had approximately $518 million accrued for all outstanding legal matters, which includes the accruals related to our Western Energy Settlement.

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 June 30, 2004, we had accrued approximately $400 million, including approximately $391 million for expected remediation costs and associated onsite, offsite and groundwater technical studies, and approximately $9 million for related environmental legal costs, which we anticipate incurring through 2027. Of the $400 million accrual, $149 million was reserved for facilities we currently operate, and $251 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 $400 million to approximately $573 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 ($85 million). Second, where the most likely outcome cannot be estimated, a range of costs is established ($315 million to $488 million) and if no one amount in that range is more likely than any other, the lower end of the range has been accrued. By type of site, our reserves are based on the following estimates of reasonably possible outcomes.

Sites	June 30, 2004 Expected	June 30, 2004 High
	(In millions)	
Operating	$149	$206
Non-operating	220	322
Superfund	31	45
Total	$400	$573

Below is a reconciliation of our accrued liability from January 1, 2004, to June 30, 2004 (in millions):

Balance as of January 1, 2004	$412
Additions/adjustments for remediation activities	7
Payments for remediation activities	(20)
Other changes, net	1
Balance as of June 30, 2004	$400

For the remainder of 2004, we estimate that our total remediation expenditures will be approximately $39 million. In addition, we expect to make capital expenditures for environmental matters of approximately $86 million in the aggregate for the years 2004 through 2008. These expenditures primarily relate to compliance with clean air regulations.

Internal PCB Remediation Project. Since 1988, TGP, our subsidiary, has been engaged in an internal project to identify and address the presence of polychlorinated biphenyls (PCBs) and other substances, including those on the EPA List of Hazardous Substances (HSL), at compressor stations and other facilities it operates. While conducting this project, TGP has been in frequent contact with federal and state regulatory agencies, both through informal negotiation and formal entry of consent orders. TGP executed a consent order in 1994 with the EPA, governing the remediation of the relevant compressor stations, and is working with the EPA and the relevant states regarding those remediation activities. TGP is also working with the Pennsylvania and New York environmental agencies regarding remediation and post-remediation activities at its Pennsylvania and New York stations.

PCB Cost Recoveries. 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 internal 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 June 30, 2004, TGP had pre-collected PCB costs by approximately $123 million. This 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 June 30, 2004, TGP has recorded a regulatory liability (included in other non-current liabilities on its balance sheet) of $92 million for 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 61 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 June 30, 2004, we have estimated our share of the remediation costs at these sites to be between $31 million and $45 million. Since the clean-up costs are estimates and are subject to revision as more information becomes available about the extent of remediation required, and because in some cases we have asserted a defense to any liability, our estimates could change. Moreover, liability under the federal CERCLA statute is joint and several, meaning that we could be required to pay in excess of our pro rata share of remediation costs. Our understanding of the financial strength of other PRPs has been considered, where appropriate, in estimating our liabilities. Accruals for these issues are included in the previously indicated estimates for Superfund sites.

It is possible that new information or future developments could require us to reassess our potential exposure related to environmental matters. We may incur significant costs and liabilities in order to comply with existing environmental laws and regulations. It is also possible that other developments, such as increasingly strict environmental laws and regulations and claims for damages to property, employees, other persons and the environment resulting from our current or past operations, could result in substantial costs and liabilities in the future. As this information becomes available, or other relevant developments occur, we will adjust our accrual amounts accordingly. While there are still uncertainties relating to the ultimate costs we may incur, based upon our evaluation and experience to date, we believe our current reserves are adequate.

Rates and Regulatory Matters

In November 2004, the FERC issued an industry-wide Proposed Accounting Release that, if enacted as written, will disallow the capitalization of certain costs that are part of our pipeline integrity program. The accounting release is proposed to be effective January 2005 following a period of public comment on the release. We are currently reviewing the release and have not determined what impact this release will have on our consolidated financial statements.

Other

Enron Bankruptcy. In December 2001, Enron Corp. and a number of its subsidiaries, including Enron North America Corp. (ENA) and Enron Power Marketing, Inc. (EPMI) filed for Chapter 11 bankruptcy protection in New York. We had various contracts with Enron marketing and trading entities, and most of the trading-related contracts were terminated due to the bankruptcy. In October 2002, we filed proofs of claims against the Enron trading entities totaling approximately $317 million. We sold $244 million of the original claims to a third party. Enron also maintained that El Paso Merchant Energy-Petroleum Company owed it approximately $3 million, and that EPM owed EPMI $46 million, each due to the termination of petroleum and physical power contracts. In both cases, we maintained that due to contractual setoff rights, no money was owed to the Enron parties. Additionally, EPM maintained that EPMI owed EPM $30 million due to the termination of a physical power contract, which is included in the $317 million of filed claims. EPMI filed a lawsuit against EPM and its guarantor, El Paso Corporation, based on the alleged $46 million liability. On June 24, 2004, the Bankruptcy Court approved a settlement agreement with Enron that resolved all of the foregoing issues as well as most other trading or merchant issues between the parties. Our European trading businesses also asserted $20 million in claims against Enron Capital and Trade Resources Limited, which are subject to separate proceedings in the United Kingdom, in addition to a corresponding claim against Enron Corp. based on a corporate guarantee. After considering the valuation and setoff arguments and the reserves we have established, we believe our overall exposure to Enron is $3 million.

In addition, various Enron subsidiaries had transportation contracts on several of our pipeline systems. Most of these transportation contracts have now been rejected, and our pipeline subsidiaries have filed proofs of claim totaling approximately $137 million. EPNG filed the largest proof of claim in the amount of approximately $128 million, which included $18 million for amounts due for services provided through the date the contracts were rejected and $110 million for damage claims arising from the rejection of its transportation contracts. EPNG expects that Enron will vigorously contest these claims. Given the uncertainty of the bankruptcy process, the results are uncertain. We have fully reserved for the amounts due through the date the contracts were rejected, and we have not recognized any amounts under these contracts since the rejection date.

Duke Litigation. Citrus Trading Corporation (CTC), a direct subsidiary of Citrus Corp. (Citrus) 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. Duke has filed in federal court an amended counter claim 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, which is currently pending before the court.

Investments in Brazil. We own and have investments in power, pipeline and production assets in Brazil with an aggregate exposure, including financial guarantees, of approximately $1.5 billion as of June 30, 2004. During 2002, Brazil experienced higher interest rates on local debt for the government and private sectors, which decreased the availability of funds from lenders outside of Brazil and decreased the amount of foreign investment in the country. During late 2003 and 2004, Brazil's general economic conditions improved and interest rate levels decreased. We currently believe that the economic difficulties in Brazil will not have a future material adverse effect on our investment in the country, but we continue to monitor its economic situation. Some of the specific issues we are experiencing in Brazil are discussed below.

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 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. A Curitiba court has ruled that the arbitration clause in the PPA is invalid, and has enjoined the project company from prosecuting its arbitration under penalty of approximately $173,000 in daily fines. The project company is appealing this ruling, and has obtained a stay order in any imposition of daily fines pending the outcome of the appeal. Our investment in the Araucaria project was $183 million at June 30, 2004. Based on the future outcome of our dispute under the PPA, we could be required to write down the value of our investment.

We own two projects located in Manaus, Brazil. The first project is a 238 MW fuel-oil fired plant known as the Manaus Project, which has a net book value of $35 million at June 30, 2004 and the second project is a 158 MW fuel-oil fired plant known as the Rio Negro Project with a net book value of $39 million at June 30, 2004. Manaus Energia purchases power from both projects through long-term PPA's. However, the Manaus Project's PPA currently expires in January 2005 and the Rio Negro Project's PPA currently expires in January 2006. As a result of changes in the Brazilian political environment in early 2004, Manaus Energia issued a request for power supply proposals for 450 MW to 525 MW of net generating capacity from 2005 to 2006. Several non-governmental organizations obtained a preliminary injunction enjoining Manaus Energia from proceeding with the bid process until a decision on the merits of their complaint was made, but that injunction has now been lifted, and Manaus Energia is free to proceed with the bid. As a result of our negotiations to extend the term of the PPA's and based the status of the legal challenges to Manaus Energia's bid process, we believe, however, that it is uncertain as to whether the bid process will proceed. If the bid process continues, the bid qualifications issued by Manaus Energia may prohibit us from supplying power from our Manaus and Rio Negro projects. Based on the potential results of the bid process and the expected outcome of our negotiations to extend the term of the PPA's, we recorded an impairment charge of approximately $135 million in the first quarter of 2004. Also, we have filed a lawsuit in the Brazilian courts against Manaus Energia on the Rio Negro Project regarding a tariff dispute related to power sales from 1999 to 2003 and have resulted in a long-term receivable of $32 million which is a subject of this lawsuit. Based on the future outcome of this lawsuit, we could be required to provide an allowance for the receivable.

We own a 50 percent interest in a 404 MW dual-fuel-fired power project known as the Porto Velho Project, located in Porto Velho, Brazil. The Porto Velho Project has two PPA's. The first PPA has a term of ten years and relates to the first phase of the project. The second PPA has a term of 20 years and relates to the second 345 MW phase of the project. We are negotiating certain provisions of both PPA's with EletroNorte, including the amount of installed capacity, energy prices, take or pay levels, the term of the first PPA and other issues. Although the current terms of the PPA's and the proposed amendments 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 was $293 million at June 30, 2004. In October 2004, the project experienced an outage associated with one of its steam turbine generators, which resulted in a partial reduction in the plant's capacity. The time required to replace or repair the steam turbine has not yet been determined.

We own a 895 MW gas-fired power plant known as the Macae project located near the city of Macae, Brazil with a net book value of $726 million at June 30, 2004. The Macae project revenues are derived from sales to the spot market, bilateral contracts and minimum capacity and revenue payments. The minimum capacity and energy revenue payments of the Macae project are guaranteed by Petrobras until August 2007 under a participation agreement. Recently Petrobras has requested that certain provisions of the participation agreement, particularly the terms of the capacity payment, be renegotiated. We have begun early discussions with Petrobras. While the current terms of the participation agreement do not indicate an impairment of our investment, a renegotiation of the participation agreement could reduce our earnings from this project beginning in 2005 and we may be required to write down the value of our investment at that time.

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 former 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 Corporation and Case Corporation.* The suit alleges, among other things, that El Paso violated the Employee Retirement Income Security Act of 1974, or ERISA, and that Case should be required to pay all amounts above the cap. Historically, amounts above the cap have 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. However, in September 2004, a judge ruled that El Paso, must indemnify Case for the $1.8 million monthly amounts above the cap. Both rulings have been appealed. We will begin making the monthly payments of approximately $1.8 million in October 2004. While the outcome of these matters is uncertain, if we were required to ultimately pay for 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. At this time, we believe amounts we have accrued for this matter are appropriate.

While the outcome of these matters cannot be predicted with certainty 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. The impact of these changes may have a material effect on our results of operations, our financial position and our cash flows in the periods these events occur.

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 2003 Annual Report on Form 10-K for a description of each type of guarantee. As of June 30, 2004, we had approximately $188 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 June 30, 2004, we had accrued $78 million related to these arrangements.

13. Retirement Benefits

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

	Quarter Ended June 30,				Six Months Ended June 30,			
	Pension Benefits		Other Postretirement Benefits		Pension Benefits		Other Postretirement Benefits	
	2004	2003	2004	2003	2004	2003	2004	2003
	(In millions)							
Service cost	$ 8	$ 9	$—	$—	$ 16	$ 18	$—	$—
Interest cost	30	34	8	9	61	68	16	18
Expected return on plan assets	(47)	(57)	(3)	(2)	(95)	(114)	(6)	(4)
Amortization of net actuarial loss	12	1	1	—	24	2	2	—
Amortization of transition obligation	—	—	2	2	—	—	4	4
Amortization of prior service cost[(1)]	(1)	(1)	—	—	(2)	(2)	—	—
Settlements, curtailment, and special termination benefits	—	—	—	—	—	—	—	(6)
Net benefit cost (income)	$ 2	$(14)	$ 8	$ 9	$ 4	$ (28)	$16	$12

(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.

We made $33 million and $58 million of cash contributions to our Supplemental Executive Retirement Plan and other postretirement plans during the six months ended June 30, 2004 and 2003. We expect to contribute an additional $5 million to the Supplemental Executive Retirement Plan and $37 million to our other postretirement plans in 2004. We do not anticipate making any other contributions to our other retirement benefit plans in 2004. We are currently evaluating the impact of the Pension Funding Equity Act enacted in 2004 on our projected funding.

On December 8, 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 was signed into law. Benefit obligations and costs reported that are related to prescription drug coverage do not reflect the impact of this legislation. In addition, we are currently evaluating new accounting standards that become effective in the third quarter of 2004 that may require changes to previously reported benefit information and to our net benefit cost for the year ending December 31, 2004.

See Note 12 for an additional matter that could impact our retirement benefit obligations.

14. Capital Stock

Common Stock

In January 2004, we issued 8.8 million shares of common stock for $74 million to satisfy the remaining stock obligation under our Western Energy Settlement.

Dividends

During the six months ended June 30, 2004, we paid dividends of $49 million to common stockholders. We have also paid dividends of approximately $51 million subsequent to June 30, 2004. The dividends on our common stock were treated as a reduction of paid-in-capital since we currently have an accumulated deficit. On November 18, 2004, the Board of Directors declared a quarterly dividend of $0.04 per share on the company's outstanding stock. The dividend will be payable on January 3, 2005 to shareholders of record on December 3, 2004. In addition, El Paso Tennessee Pipeline Co., our subsidiary, pays dividends (2.0625% per quarter, 8.25% per annum) of approximately $6 million each quarter on its Series A cumulative preferred stock.

15. Segment Information

During 2004, we reorganized our business structure into two primary business lines, regulated and unregulated, and modified our operating segments. Historically, our operating segments included Pipelines, Production, Merchant Energy and Field Services. As a result of this reorganization, we eliminated our Merchant Energy segment and established individual Power and Marketing and Trading segments. All periods presented reflect this change in segments. 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 operations include our general and administrative functions as well as a telecommunications business, and various other contracts and assets, all of which are immaterial. These other assets and contracts include financial services, LNG and related items. During the first quarter of 2004, we reclassified our petroleum ship charter operations from discontinued operations to continuing corporate operations. During the second quarter of 2004, we reclassified our Canadian and certain other international natural gas and oil production operations from our Production segment to discontinued operations in our financial statements. Our operating results for all periods presented reflect these changes.

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 June 30:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2004	2003	2004	2003
	(In millions)			
Total EBIT	$ 498	$(227)	$ 840	$(102)
Interest and debt expense	(410)	(463)	(833)	(877)
Distributions on preferred interests of consolidated subsidiaries	(6)	(17)	(12)	(38)
Income taxes	(37)	410	(47)	513
Income (loss) from continuing operations	$ 45	$(297)	$ (52)	$(504)

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

Quarter Ended June 30,	Regulated	Unregulated					
	Pipelines	Production	Marketing and Trading	Power	Field Services	Corporate[1]	Total
			(In millions)				
2004							
Revenues from external customers	$595	$144[2]	$ 187	$202	$375	$ 29	$1,532
Intersegment revenues	22	286[2]	(328)	34	53	(75)	(8)[3]
Operation and maintenance	172	77	10	97	25	(8)	373
Depreciation, depletion and amortization	101	131	3	12	4	12	263
(Gain) loss on long-lived assets	—	—	—	16	6	(5)	17
Operating income (loss)	$260	$202	$(154)	$ 56	$ 7	$ (1)	$ 370
Earnings from unconsolidated affiliates	41	2	—	24	31	—	98
Other income	8	—	2	26	—	14	50
Other expense	(1)	—	—	(4)	(11)	(4)	(20)
EBIT	$308	$204	$(152)	$102	$ 27	$ 9	$ 498
2003							
Revenues from external customers	$588	$(90)[2]	$ 506	$206	$255	$ 33	$1,498
Intersegment revenues	32	658[2]	(782)	137	123	(97)	71[3]
Operation and maintenance	325	90	25	146	39	—	625
Depreciation, depletion and amortization	101	141	6	27	8	19	302
(Gain) loss on long-lived assets	(8)	(5)	(2)	—	(5)	415	395
Operating income (loss)	$112	$308	$(306)	$ 68	$(15)	$(439)	$ (272)
Earnings (losses) from unconsolidated affiliates	25	4	—	98	(41)	—	86
Other income	9	—	8	21	—	8	46
Other expense	(1)	—	—	(2)	—	(84)	(87)
EBIT	$145	$312	$(298)	$185	$(56)	$(515)	$ (227)

(1) Includes our corporate and telecommunications activities and eliminations of intercompany transactions. Our intersegment revenues, along with our intersegment operating expenses, were incurred in the normal course of business between our operating segments. We record an intersegment revenue elimination, which is the only elimination included in the "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 petroleum markets operations.

Six Months Ended June 30,	Regulated	Unregulated					
	Pipelines	Production	Marketing and Trading	Power	Field Services	Corporate[1]	Total
			(In millions)				
2004							
Revenues from external customers	$1,293	$ 277[2]	$ 368	$ 351	$720	$ 72	$3,081
Intersegment revenues	45	599[2]	(668)	92	95	(163)	—[3]
Operation and maintenance	352	162	22	195	51	(8)	774
Depreciation, depletion and amortization	201	271	6	28	7	25	538
(Gain) loss on long-lived assets	(1)	—	—	240	8	(8)	239
Operating income (loss)	$ 608	$ 405	$ (329)	$(132)	$ 17	$ 6	$ 575
Earnings from unconsolidated affiliates	74	3	—	53	68	—	198
Other income	14	—	5	48	—	36	103
Other expense	(2)	—	—	(6)	(22)	(6)	(36)
EBIT	$ 694	$ 408	$ (324)	$ (37)	$ 63	$ 36	$ 840

Six Months Ended June 30,	Regulated Pipelines	Unregulated Production	Unregulated Marketing and Trading	Unregulated Power	Unregulated Field Services	Corporate[1]	Total
	(In millions)						
2003							
Revenues from external customers	$1,310	$ 150[2]	$ 653	$ 428	$656	$ 68	$3,265
Intersegment revenues	63	1,153[2]	(1,317)	157	280	(204)	132[3]
Operation and maintenance	501	175	69	311	70	55	1,181
Depreciation, depletion and amortization	196	299	13	47	18	41	614
(Gain) loss on long-lived assets	(8)	(5)	(3)	(6)	(4)	435	409
Operating income (loss)	$ 496	$ 745	$ (747)	$ 63	$(15)	$(550)	$ (8)
Earnings (losses) from unconsolidated affiliates	68	10	—	(103)	(13)	(10)	(48)
Other income	15	3	15	35	—	15	83
Other expense	(5)	—	—	(6)	(1)	(117)	(129)
EBIT	$ 574	$ 758	$ (732)	$ (11)	$(29)	$(662)	$ (102)

(1) Includes our corporate and telecommunications activities and eliminations of intercompany transactions. Our intersegment revenues, along with our intersegment operating expenses, were incurred in the normal course of business between our operating segments. We record an intersegment revenue elimination, which is the only elimination included in the "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 petroleum markets operations.

Total assets by segment are presented below:

	June 30, 2004	December 31, 2003
	(In millions)	
Regulated		
Pipelines	$15,561	$15,753
Unregulated		
Production	3,876	3,767
Marketing and Trading	2,176	2,666
Power	5,524	7,074
Field Services	1,980	1,990
Total segment assets	29,117	31,250
Corporate	3,445	4,030
Discontinued operations	165	1,804
Total consolidated assets	$32,727	$37,084

16. 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. 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.

	Quarter Ended June 30,					Six Months Ended June 30,				
	GulfTerra	Citrus	Great Lakes	Other Investments	Total	GulfTerra	Citrus	Great Lakes	Other Investments	Total
	(In millions)									
2004										
Operating results data:										
Operating revenues	$138	$61	$32	$396	$627	$265	$114	$68	$ 764	$1,211
Operating expenses	84	25	13	297	419	166	48	26	564	804
Income from continuing operations	29	16	11	49	105	60	26	24	107	217
Net income[(1)]	29	21	11	49	110	60	28	24	107	219
2003										
Operating results data:										
Operating revenues	$199	$36	$30	$503	$768	$387	$111	$65	$1,060	$1,623
Operating expenses	153	4	14	344	515	290	45	28	713	1,076
Income from continuing operations	29	4	7	91	131	57	15	20	210	302
Net income[(1)]	29	4	7	91	131	57	15	20	210	302

(1) Includes net income (loss) of $8 million and $(2) million for the quarters ended June 30, 2004 and 2003, and net income of $21 million and $5 million for the six months ended June 30, 2004 and 2003, related to our proportionate share of affiliates in which we hold a greater than 50 percent interest.

Our income statement reflects our share of net earnings (losses) 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. The table below reflects our earnings (losses) from unconsolidated affiliates for the periods ended June 30:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2004	2003	2004	2003
	(In millions)			
Proportional share of income of investees	$110	$131	$219	$302
Impairment charges and gains and losses on sale of investments				
Chaparral impairment[(1)]	—	—	—	(207)
Milford power facility impairment[(2)]	—	—	(2)	(86)
Dauphin Island/Mobile Bay impairment[(3)]	—	(80)	—	(80)
Power plants held for sale impairments[(3)]	(19)	—	(35)	—
Gain on sales of CAPSA/CAPEX	—	24	—	24
Other gains (losses)	1	(3)	—	(13)
Gain on issuance of GulfTerra common units	—	12	3	12
Other	6	2	13	—
Total earnings (losses) from unconsolidated affiliates	$ 98	$ 86	$198	$(48)

(1) This impairment resulted from other than temporary declines in the investment's fair value based on developments in our power business and the power industry (see Note 6).

(2) This impairment resulted from a write-off of notes receivable and accruals on contracts due to ongoing difficulty at the project level.

(3) These impairments resulted from the anticipated sales of these investments.

We received distributions and dividends from our investments of $74 million for each of the quarters ended June 30, 2004 and 2003, and $168 million and $157 million for the six months ended June 30, 2004 and 2003.

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 June 30:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2004	2003	2004	2003
	(In millions)			
Operating revenue	$ 87	$ 76	$160	$127
Other revenue — management fees	3	4	5	6
Cost of sales	37	37	60	59
Reimbursement for operating expenses	36	32	66	68
Other income	2	2	5	5
Interest income	2	3	4	6
Interest expense	—	1	—	3

GulfTerra. Prior to 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 contributes to our income through our general partner interest and our ownership of common and preference units. We do not have any loans to or from GulfTerra.

We had the following interests in GulfTerra as of June 30, 2004:

	Book Value
	(In millions)
One Percent General Partner(1)	$194
Common Units(2)	245
Series C Units(3)	329
Total	$768

(1) As of June 30, 2004, Enterprise had an effective 50 percent ownership interest in the general partner, which we have reflected in our balance sheet as minority interest of $96 million. We also had $181 million of indefinite-lived intangible assets related to the general partner interest as of June 30, 2004.

(2) As of June 30, 2004, we owned 17.3 percent of the common units of GulfTerra. The remaining units are owned by public holders, including the partnership employees and management, none of which individually own more than 10 percent.

(3) As of June 30, 2004, we owned all of the Series C units of GulfTerra.

In September 2004, in connection with the closing of the merger between GulfTerra and Enterprise, we completed the sale of substantially all of our interests in GulfTerra, as well as certain processing assets to affiliates of Enterprise. Our total gross cash proceeds from the sale were approximately $1.03 billion and we will record a gain of approximately $5 million as a result of this transaction including the elimination of approximately $480 million in goodwill associated with our Field Services segment. Of the $480 million of goodwill that will be eliminated, approximately $397 million will not be deductible for tax purposes. As a result, we will recognize a significant tax gain and tax expense associated with the transaction in the third quarter of 2004. The assets sold were our interest in the general partner of GulfTerra, 10.9 million Series C units, 2.9 million GulfTerra common units, and nine processing plants located in South Texas. In addition to the cash proceeds, we received a 9.9 percent interest in the general partner of the combined organization, Enterprise Products GP, LLC. Our remaining GulfTerra common units were exchanged for approximately 13.5 million common units in Enterprise as a result of the merger.

Our segments also conduct transactions in the ordinary course of business with GulfTerra, including sales of natural gas and operational services. Below is the summary of our transactions with GulfTerra for the periods ended June 30:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2004	2003	2004	2003
	(In millions)			
Revenues received from GulfTerra				
Marketing and Trading	$ 6	$ 6	$15	$16
Field Services	—	—	1	5
	$ 6	$ 6	$16	$21
Expenses paid to GulfTerra				
Field Services	$34	$25	$67	$42
Marketing and Trading	1	8	2	19
Production	2	2	4	4
	$37	$35	$73	$65
Reimbursements received from GulfTerra				
Field Services	$23	$22	$45	$46

For a further discussion of our relationships with GulfTerra, see our 2003 Annual Report on Form 10-K.

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 2003 Annual Report on Form 10-K, and the financial statements and notes presented in Item 1 of this Form 10-Q.

During the second quarter of 2004, we reclassified our historical Canadian and certain other international natural gas and oil production operations from our Production segment to discontinued operations in our financial statements for all periods presented. In addition, our results for the quarter and six months ended June 30, 2003 have been restated to reflect the accounting impact of a reduction in our historically reported proved natural gas and oil reserves and to revise the manner in which we accounted for certain hedges, primarily those associated with our anticipated natural gas production. These restatements are further discussed in our 2003 Annual Report on Form 10-K.

Overview

Business Update

In December 2003, our management presented its Long-Range Plan for the Company. This plan, among other things, defined our core businesses, established a timeline for debt reductions and sales of non-core businesses and assets and set financial goals for the future. During 2004, and through the filing date of this Form 10-Q, we have made significant progress in the areas outlined in that plan, including:

- completing or announcing sales of assets and investments of approximately $3.3 billion (see Item 1, Financial Statements, Note 4)
- retiring, eliminating, or refinancing approximately $3.4 billion of maturing debt and other obligations, ($1.9 billion through June 30, 2004) (see Item 1, Financial Statements, Note 11);
- finalizing the Western Energy Settlement, which substantially resolved our principal exposure relating to the western energy crisis and successfully raising funds to satisfy a significant portion of our current obligations under that settlement (see Item 1, Financial Statements, Note 12); and
- entering into a new credit agreement to refinance our existing revolving credit facility with an aggregate of $3 billion in financings consisting of a $1.25 billion, five year term loan, a new $1.0 billion three year revolving credit facility, and a five year, $750 million funded letter of credit facility, all of which will become available to us upon the filing of this Quarterly Report on Form 10-Q (see Note 11).

Liquidity Update

We believe that the restatement of our historical financial statements mentioned above would have constituted an event of default under our existing revolving credit facility and various other financing transactions; specifically under the provisions in these arrangements related to representations and warranties on the accuracy of our historical financial statements and on our debt to total capitalization ratio. During 2004, we received several waivers on our existing revolving credit facility and various other financing arrangements to address certain of these issues. With the filing of these financial statements, we are in compliance with our existing revolving credit facility and with the various other financings on which we received waivers. Three of our subsidiaries have indentures associated with their public debt that contain $5 million cross-acceleration provisions. These indentures state that should an event of default occur resulting in the acceleration of other debt obligations of such subsidiaries in excess of $5 million, the long-term debt obligations containing such provisions could be accelerated. The acceleration of our debt would adversely affect our liquidity position, and in turn, our financial condition. Our subsidiary, El Paso CGP Company, has not yet filed its financial statements for the second quarter of 2004, as required under several of its financing arrangements. We believe we will file El Paso CGP's financial statements prior to any notice being given or within the allowed time frames under these financing arrangements such that there will be no event of default.

Our existing revolving credit facility matures in June 2005. As of June 30, 2004, we had $600 million outstanding (which was repaid in September 2004) and $1.1 billion of letters of credit issued under this facility. In November 2004, we entered into a new credit agreement with a group of lenders for an aggregate of $3 billion in financings that will become available to us upon the filing of this Form 10-Q. This new credit agreement will replace our existing revolving credit facility and will consist of a $1.25 billion, five year term loan, a new $1 billion, three year revolving credit facility under which we can issue letters of credit, and an additional five year, $750 million funded letter of credit facility. The letter of credit facility will provide us the ability to issue letters of credit or borrow any unused capacity as loans. The new credit agreement will be collateralized by our interests in EPNG, TGP, ANR, CIG, WIC, ANR Storage Company, and Southern Gas Storage Company.

Our new credit agreement will provide approximately $220 million in net additional borrowing availability as compared to our existing revolving credit facility. Upon the closing of the new credit agreement, letters of credit of approximately $1.2 billion issued under our existing revolving credit facility will be supported by the $750 million letter of credit facility and by approximately $0.4 billion of the new $1 billion revolving credit facility. We will use the $1.25 billion term loan proceeds to repay certain financing obligations, manage our liquidity, prepay upcoming debt maturities, and provide for other general corporate purposes.

Our subsidiaries are a significant potential source of liquidity to us, and they participate in our cash management program to the extent they are permitted to do so under their financing agreements and indentures. Under the cash management program, depending on whether participating subsidiaries have short-term cash requirements or surpluses, we either provide cash to them or they provide cash to us. If we were to incur an event of default under our credit facilities, we would be unable to obtain cash from our pipeline subsidiaries, which are the primary source of cash under this program. In addition, our ownership in a number of our subsidiaries and investments currently serves as collateral under our existing revolving credit facility and our other financings, and will serve as collateral under the new credit agreement. If the lenders were to exercise their rights to this collateral, we could lose our ownership interest in these subsidiaries or be required to liquidate these investments.

We believe we will be able to meet our ongoing liquidity and cash needs through a combination of sources, including cash on hand, cash generated from our operations, borrowings under our new credit agreement, proceeds from asset sales, reduction of discretionary capital expenditures and the possible issuance of long-term debt, and common or preferred equity securities. However, a number of factors could influence our liquidity sources, as well as the timing and ultimate outcome of our ongoing efforts and plans.

Capital Structure

Our 2003 Annual Report on Form 10-K 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.

During the six months ended June 30, 2004, we continued to reduce our debt as part of our Long-Range Plan announced in December 2003. Our activity during the six months ended June 30, 2004 is as follows (in millions):

Short-term financing obligations, including current maturities	$ 1,457
Long-term financing obligations	20,275
Securities of subsidiaries	447
Total debt and securities of subsidiaries as of December 31, 2003	22,179
Principal amounts borrowed	50
Repayments/retirements of principal[1]	(1,024)
Sales of entities[2]	(887)
Other	(37)
Total debt and securities of subsidiaries as of June 30, 2004	$20,281

(1) Amount includes $250 million of repayments under our existing revolving credit facility and excludes $370 million of repayments of long-term debt related to our Aruba refinery classified as part of our discontinued operations prior to the sale of this facility in early 2004.

(2) This debt was eliminated when we sold our interests in Mohawk River Funding IV and Utility Contract Funding.

For a further discussion of our long-term debt and other financing obligations, and other credit facilities, see Item 1, Financial Statements, Note 11.

Capital Resources and Liquidity

Overview of Cash Flow Activities for the Six Months Ended June 30, 2004 and 2003

For the six months ended June 30, 2004 and 2003, our cash flows are summarized as follows:

	2004	2003
	(In millions)	
Cash flows from continuing operating activities		
Net loss before discontinued operations	$ (52)	$ (513)
Non-cash income adjustments	823	965
Changes in assets and liabilities	(636)	467
Cash flows from continuing operating activities	135	919
Cash flows from continuing investing activities	(91)	(1,241)
Cash flows from continuing financing activities	(62)	516
Change in cash and cash equivalents related to continuing operations	(18)	194
Discontinued operations		
Cash flows from operating activities	161	95
Cash flows from investing activities	1,113	245
Cash flows from financing activities	(1,274)	(340)
Change in cash and cash equivalents related to discontinued operations	—	—
Total change in cash and cash equivalents	$ (18)	$ 194

During the first six months of 2004, we generated cash from several sources, including our principal continuing operations as well as through asset sales in both our continuing and discontinued operations. We used a major portion of that cash to fund our capital expenditures and to make payments to retire long-term debt. Overall, our cash sources and uses are summarized as follows (in billions):

Cash inflows from continuing operations	
Cash flows from operating activities	$0.1
Net proceeds from the sale of assets and investments	0.2
Net change in restricted cash[1]	0.4
Other	0.2
Total cash inflows from continuing operations	0.9
Cash outflows from continuing operations	
Additions to property, plant and equipment	(0.8)
Payments to retire long-term debt	(1.0)
Total cash outflows from continuing operations	(1.8)
Cash flows from discontinued operations	
Cash from operations	0.1
Net proceeds from sale of assets	1.2
Payments to retire long-term debt	(0.4)
Total net cash inflows from discontinued operations	0.9
Net increase in cash	$ —

(1) Amounts consist primarily of the release of escrowed funds related to the Western Energy Settlement.

As of November 15, 2004, we had available cash on hand and borrowing capacity under our existing revolving credit facility totaling $2.2 billion. Upon closing our new credit agreement effective with this filing, our net available liquidity will increase by approximately $220 million.

Cash From Continuing Operating Activities

Overall, cash generated from our continuing operating activities was $0.1 billion during the first six months of 2004 versus $0.9 billion during the same period of 2003. The $0.8 billion decrease in operating cash flow was due primarily to a payment of $0.6 billion to settle the principal litigation under the Western Energy Settlement in the second quarter of 2004.

Cash From Continuing Investing Activities

Net cash used in our continuing investing activities was $0.1 billion for the six months ended June 30, 2004. Our investing activities consisted of the following (in billions):

Production exploration, development and acquisition expenditures	$(0.4)
Pipeline expansion, maintenance and integrity projects	(0.4)
Restricted cash activity[1]	0.4
Proceeds from the sale of assets and investments	0.2
Other	0.1
Total continuing investing activities	$(0.1)

[1] Amounts consist primarily of the release of escrowed funds related to the Western Energy Settlement.

For the remainder of 2004, we expect our total capital expenditures to be approximately $1.2 billion, which includes approximately $0.5 billion for our Production segment and $0.7 billion for our Pipelines segment.

Cash From Continuing Financing Activities

Net cash used by our continuing financing activities was $0.1 billion for the six months ended June 30, 2004. Cash used in our financing activities included net repayments of $1.0 billion made to retire third party long-term debt. Cash provided from our financing activities included $0.9 billion of cash generated by our discontinued operations as further discussed below. We reflect the net cash generated by our discontinued operations as a cash inflow to our continuing financing activities.

Cash from Discontinued Operations

During the first six months of 2004, our discontinued operations contributed $0.9 billion of cash. We generated $0.1 billion in cash in these operations, received proceeds from the sales of the Eagle Point and Aruba refineries of approximately $1.2 billion and paid long-term debt of $0.4 billion related to the Aruba refinery.

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 and valuation methodology as of June 30, 2004:

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	$ 27	$ 47	$ —	$ —	$ —	$ 74
Liabilities	(32)	(57)	(11)	(6)	—	(106)
Total derivatives designated as hedges	(5)	(10)	(11)	(6)	—	(32)
Assets from power contract restructuring derivatives[1]	133	270	220	323	—	946
Other commodity-based derivatives						
Exchange-traded positions[2]						
Assets	24	58	46	—	—	128
Liabilities	(53)	(8)	—	—	—	(61)
Non-exchange-traded positions						
Assets	330	279	120	150	41	920
Liabilities[1]	(592)	(593)	(179)	(199)	(50)	(1,613)
Total other commodity-based derivatives	(291)	(264)	(13)	(49)	(9)	(626)
Total commodity-based derivatives	$(163)	$ (4)	$ 196	$ 268	$ (9)	$ 288

(1) Includes $269 million of intercompany derivatives that eliminate in consolidation and had no impact on our consolidated assets and liabilities from price risk management activities for the six months ended June 30, 2004.

(2) Exchange-traded positions are 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, 2004 to June 30, 2004:

	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, 2004	$(31)	$ 1,925	$(488)	$ 1,406
Fair value of contract settlements during the period	34	(1,037)[1]	180	(823)
Change in fair value of contracts	(35)	58	(315)[2]	(292)
Option premiums received, net	—	—	(3)	(3)
Net change in contracts outstanding during the period	(1)	(979)	(138)	(1,118)
Fair value of contracts outstanding at June 30, 2004	$(32)	$ 946	$(626)	$ 288

(1) Includes $861 million and $75 million of derivative contracts sold in connection with the sale of Utility Contract Funding and Mohawk River Funding IV in 2004. See Item I, Financial Statements, Notes 4 and 6 for additional information on these sales.

(2) In the second quarter of 2004, we reclassified a $69 million liability from our Western Energy Settlement obligation to our price risk management activities.

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.

The change in fair value of contracts during the year 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. During 2004, we reorganized our business structure into two primary business lines, regulated and unregulated, and modified our operating segments. Historically, our operating segments included Pipelines, Production, Merchant Energy and Field Services. As a result of this reorganization, we eliminated our Merchant Energy segment and established individual Power and Marketing and Trading segments. All periods presented reflect this change in segments. 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, all of which are immaterial. The other assets and contracts include financial services, LNG and related items. During the first quarter of 2004, we reclassified our petroleum ship charter operations from discontinued operations to our continuing corporate operations. In the second quarter of 2004, we reclassified our Canadian and certain other international natural gas and oil production operations from our Production segment to discontinued operations in our financial statements. Our operating results for all periods presented reflect these changes.

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 June 30:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2004	2003	2004	2003
	(In millions)			
Regulated Businesses				
Pipelines	$ 308	$ 145	$ 694	$ 574
Unregulated Businesses				
Production	204	312	408	758
Marketing and Trading	(152)	(298)	(324)	(732)
Power	102	185	(37)	(11)
Field Services	27	(56)	63	(29)
Segment EBIT	489	288	804	560
Corporate	9	(515)	36	(662)
Consolidated EBIT from continuing operations	498	(227)	840	(102)
Interest and debt expense	(410)	(463)	(833)	(877)
Distributions on preferred interests of consolidated subsidiaries	(6)	(17)	(12)	(38)
Income taxes	(37)	410	(47)	513
Income (loss) from continuing operations	45	(297)	(52)	(504)
Discontinued operations, net of income taxes	(29)	(939)	(138)	(1,154)
Cumulative effect of accounting changes, net of income taxes	—	—	—	(9)
Net income (loss)	$ 16	$(1,236)	$(190)	$(1,667)

Overview of Results of Operations

For the six months ended June 30, 2004, our consolidated EBIT from continuing operations was $840 million of which $804 million was our segment EBIT. During the six months, our Pipelines, Production and Field Services segments contributed $1,165 million of combined EBIT. These positive contributions were partially offset by EBIT losses of $361 million in our Power and Marketing and Trading segments. The following overview summarizes the results of operations of our operating segments.

Pipelines Our Pipelines segment generated EBIT of $694 million, which was generally consistent with our expectations for the period.

Production Our Production segment generated EBIT of $408 million, which was above our expectations for the period. Higher than expected commodity prices and lower than expected depreciation costs, due to the impact of the reserve and hedge restatements in periods prior to 2004, more than offset lower than expected production volumes and higher than expected production costs.

Marketing and Trading Our Marketing and Trading segment generated an EBIT loss of $324 million, which was below our expectations. The performance was driven primarily by mark-to-market losses in our natural gas portfolio due to natural gas price increases in the period. Our natural gas portfolio exposure was impacted by the hedge restatement in periods prior to 2004, resulting in a mark-to-market position that will result in losses if natural gas prices increase.

Power Our Power segment generated an EBIT loss of $37 million, which was below our expectations for the period, primarily due to asset impairments of $281 million. These impairments were primarily related to events at two power plants in Brazil in the first quarter of 2004 that may make it difficult to extend their power sales agreements that expire in 2005 and 2006, and due to certain of our domestic operations which were sold or are being sold.

Field Services Our Field Services segment generated EBIT of $63 million, which was consistent with our expectations for the period and impacted by the significant asset sales activity in the segment in 2003.

For the remainder of 2004, we expect the trends discussed above to continue, given the historic stability in our pipeline business and the current favorable pricing environment for natural gas. We expect our EBIT to decline in our Field Services segment in the fourth quarter of 2004 as a result of the completion of sales of our interests in GulfTerra and a majority of our remaining processing assets. In our Power segment, we expect to generate additional EBIT losses as a result of liquidating our power contract restructuring derivatives and as we continue to sell our domestic power plant portfolio. Internationally, we continue to foresee challenges in our operating areas, particularly in Brazil where we have significant power investments. Finally, we anticipate our Marketing and Trading segment's EBIT will continue to be volatile due to unpredictable changes in natural gas and power prices as they relate to our historical trading portfolio as we transition toward a core marketing business.

Our earnings in each period were impacted both favorably and unfavorably by a number of factors affecting our businesses that are enumerated in the table below. The discussion that follows summarizes these factors and their impact on our operating segments and our corporate activities. For a more detailed discussion of these factors and other items impacting our financial performance for the six months ended June 30, see the individual segment and other results included in Item 1, Financial Statements, Notes 5, 6, and 16.

	Operating Segments					
	Pipelines	Production	Marketing and Trading	Power	Field Services	Corporate
			(In millions)			
2004						
Asset and investment impairments, net of gain (loss) on sale	$ (1)	$ —	$ —	$(272)	$(11)	$ 8
Restructuring charges	(5)	(11)	(2)	(3)	(1)	(11)
Total	$ (6)	$(11)	$ (2)	$(275)	$(12)	$ (3)
2003						
Asset and investment impairments, net of gain (loss) on sale	$ 8	$ 5	$ 3	$(269)	$(75)	$(443)
Restructuring charges	(1)	(4)	(4)	(4)	(3)	(84)
Western Energy Settlement[1]	(159)	—	(6)	—	—	(3)
Total	$(152)	$ 1	$ (7)	$(273)	$(78)	$(530)

[1] Includes $44 million of accretion expense and other charges and is included in operations and maintenance expense in our consolidated statements of income.

The following is a discussion of the comparative quarterly and six month period results, including a discussion of the items above, of each of our business segments as well as our corporate activities, interest and debt expense, distributions on preferred interests of consolidated subsidiaries, income taxes and the results of our discontinued operations.

Regulated Businesses — Pipelines Segment

Our Pipelines segment owns and operates our interstate natural gas transmission businesses. For a further discussion of the business activities of our Pipelines segment, see our 2003 Annual Report on Form 10-K.

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

Pipelines Segment Results	Quarter Ended June 30, 2004	Quarter Ended June 30, 2003	Six Months Ended June 30, 2004	Six Months Ended June 30, 2003
	(In millions, except volume amounts)			
Operating revenues	$ 617	$ 620	$ 1,338	$ 1,373
Operating expenses	(357)	(508)	(730)	(877)
Operating income	260	112	608	496
Other income	48	33	86	78
EBIT	$ 308	$ 145	$ 694	$ 574
Throughput volumes (BBtu/d)[1]	19,935	18,993	21,223	21,268

[1] Throughput volumes exclude volumes related to our equity investments in the Portland Natural Gas Transmission System and EPIC Energy Australia Trust which were sold in the fourth quarter of 2003 and second quarter of 2004. In addition, volumes exclude intrasegment activities. Throughput volumes includes volumes related to our Mexico investments which were transferred from our Power segment effective January 1, 2004.

Operating Results (EBIT)

The following factors contributed to our overall EBIT increases of $163 million and $120 million for the quarter and six months ended June 30, 2004 as compared to the same periods ended June 30, 2003:

	Quarter Ended June 30,				Six Months Ended June 30,			
	Revenue	Expense	Other	EBIT Impact	Revenue	Expense	Other	EBIT Impact
	Favorable/(Unfavorable) (In millions)				Favorable/(Unfavorable) (In millions)			
ANR								
Dakota contract termination	$(12)	$ 12	$ –	$ –	$(28)	$ 27	$ –	$ (1)
Contract remarketing/restructurings	(6)	–	–	(6)	(26)	–	–	(26)
Southern Natural Gas Company (SNG)								
Equity earnings from Citrus	–	–	15	15	–	–	6	6
Mainline expansions	9	(1)	(2)	6	19	(4)	(3)	12
EPNG								
Western Energy Settlement — 2003	–	154	–	154	–	158	–	158
Lower power purchase costs in 2003	–	–	–	–	–	(4)	–	(4)
Risk sharing mechanism termination	(6)	–	–	(6)	(12)	–	–	(12)
Capacity obligation — former FR customers	–	–	–	–	(4)	–	–	(4)
CIG								
Table Rock facility sold in 2003	–	(6)	–	(6)	–	(6)	–	(6)
Storage facility gas loss replacement – 2004	–	–	–	–	–	(6)	–	(6)
Change to regulated depreciation method	–	(2)	–	(2)	–	(4)	–	(4)
Other								
Fuel recoveries, net of gas used	11	–	–	11	8	–	–	8
Favorable resolution of measurement dispute — TGP	–	–	–	–	10	–	–	10
Mexico investments[1]	2	(1)	5	6	5	(3)	8	10
Other	(1)	(5)	(3)	(9)	(7)	(11)	(3)	(21)
Total	$ (3)	$151	$15	$163	$(35)	$147	$ 8	$120

[1] Transferred from our Power segment effective January 1, 2004.

The renegotiation or restructuring of several contracts on our pipeline systems will continue to unfavorably impact our operating results and EBIT for the remainder of 2004, among other items noted below.

Guardian Pipeline, which is owned in part by We Energies, is currently providing a portion of its firm transportation requirements and directly competes with ANR for a portion of the markets in Wisconsin. Additionally, ANR will continue to experience lower operating revenues and lower operating expenses for the remainder of 2004 based on the termination of the Dakota gasification facility contract on its system. However, the termination of this contract will not have a significant overall impact on operating income and EBIT.

EPNG's risk sharing provision, which provided revenue net of its sharing obligations, expired at the end of 2003 and will continue to unfavorably impact our comparative EBIT, as reflected above, for the remainder of 2004. The impact of the capacity obligation for former full requirements (FR) customers reflected above terminated with the completion of Phases I and II of EPNG's Line 2000 Power-up project in 2004. As a result, EPNG is now able to re-market this capacity; however, it must demonstrate that such sales do not adversely impact its service to its firm customers and it is at risk for portions of the capacity that were turned back to EPNG on a permanently released basis.

Our pipeline operating results in future periods will also be impacted by other factors in addition to those noted above. ANR has entered into an agreement with a shipper to restructure another of its transportation contracts on its Southeast Leg as well as a related gathering contract. We anticipate this restructuring will be completed in March 2005 upon which ANR will receive approximately $26 million, at which time this amount will be reflected in earnings.

In November 2004, the FERC issued an industry-wide Proposed Accounting Release that, if enacted as written, will disallow the capitalization of certain costs that are part of our pipeline integrity program. The accounting release is proposed to be effective January 2005 following a period of public comment on the release. We are currently reviewing the release and have not determined the impact of this release, if any, on our consolidated financial statements.

Unregulated Businesses — Production Segment

Our Production segment conducts our natural gas and oil exploration and production activities with a long-term strategy of developing production opportunities primarily in the U.S. and Brazil. In July 2004, we acquired an additional 50 percent interest in UnoPaso to increase our production operations in Brazil. Our operating results are driven by a variety of factors including the ability to locate and develop economic natural gas and oil reserves, extract those reserves with minimal production costs and sell our products at attractive prices.

We are currently divesting our international production properties that are not part of our long-term strategy and as of November 2004 we have sold all of our Canadian operations and substantially all of our operations in Indonesia. Beginning in the second quarter of 2004, these operations have been treated as discontinued operations as further discussed in Item 1, Financial Statements, Note 4. All periods reflect this change.

Production and Capital Expenditures

For the six months ended June 30, 2004, our total equivalent production has declined approximately 73 Bcfe or 32 percent as compared to the same period in 2003 primarily due to asset sales, normal production declines and disappointing drilling results. Our average daily production through October 2004 has been as follows:

January-October 2004	820 MMcfe/d
Month of October 2004	761 MMcfe/d

Our year to date 2004 and October 2004 production levels were negatively impacted by hurricanes that occurred in September 2004 in the Gulf of Mexico. The hurricanes caused us to shut-in production and also caused damage to third party facilities that transport our production. We continue to experience reduced production levels in our offshore Gulf of Mexico operations as a result of the damage to third party facilities and do not expect these facilities to return to full production until mid-2005.

As mentioned above, in July 2004, we acquired the remaining 50 percent interest in our UnoPaso investment in Brazil. Prior to this acquisition, we treated our interest in UnoPaso as an equity method investment and, therefore, did not include our proportionate share of its production in our average daily production amounts. Subsequent to the acquisition of the remaining interest, we began consolidating the operations of UnoPaso, which is producing an average of approximately 55 MMcfe/d. Future trends in production will be dependent upon the amount of capital allocated to our Production segment, the level of success in our drilling programs and any future asset sales or acquisitions.

Through September 2004, we have spent $616 million in capital expenditures for acquisition, exploration, and development activities. Based on the results to date of our 2004 drilling program, we expect our domestic unit of production depletion rate to increase from $1.64 per Mcfe during the second quarter 2004 to $1.74 per Mcfe for the third quarter of 2004 and to $1.80 per Mcfe for the fourth quarter of 2004.

Production Hedging

We hedge our natural gas and oil production through the use of derivatives to stabilize cash flows and reduce the risk of downward commodity price movements on our sales. Our hedging strategy only partially reduces our exposure to downward movements in commodity prices and, as a result, our reported results of operations, financial position and cash flows can be impacted significantly by movements in commodity prices from period to period. For a further discussion of our hedging program, refer to our 2003 Annual Report on Form 10-K.

In 2004, we have entered into the following additional hedges on our future natural gas and oil production:

	Volume (BBtu)	Average Hedge Price (per MMbtu)	Duration
Natural gas	5,325	$ 5.62	July 2004-May 2007

	Volume (MBbls)	Average Hedge Price (per Bbl)	Duration
Oil (Brazil)	1,119	$ 35.15	August 2004-December 2007

In addition, in the fourth quarter of 2004, we entered into additional transactions in our Marketing and Trading segment designed to provide price protection to El Paso from natural gas price declines in 2005 and 2006. These "put" contracts will be marked-to-market in the operating results of our Marketing and Trading segment and will not be treated as hedges for accounting purposes in the operating results of our Production segment. These contracts will provide El Paso with a floor price of $6.00 per MMBtu on 60 TBtu of our natural gas production in 2005 and 120 TBtu in 2006. El Paso paid a premium of approximately $67 million, or $0.37 per MMBtu, for the transactions and, as a result, will have no future cash margin requirements under the contracts.

Further, we are reviewing a separate strategy under which we would designate certain of the natural gas derivatives that are currently marked to market in our Marketing and Trading segment as hedges of our natural gas production. Transactions of this type would be treated as hedges for accounting purposes and would generally have the effect of hedging a portion of our natural gas production volumes at current market prices, while reducing the earnings exposure in our Marketing and Trading segment to future natural gas price changes. These derivative hedge designations would have no impact on the company's overall cash flow in any period, but would impact the timing of recognizing the changes in the fair value of these derivatives in El Paso's overall operating results.

Operating Results

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

Production Segment Results	Quarter Ended June 30, 2004	Quarter Ended June 30, 2003	Six Months Ended June 30, 2004	Six Months Ended June 30, 2003
	(In millions, except volumes and prices)			
Operating revenues:				
Natural gas	$ 363	$ 494	$ 731	$ 1,126
Oil, condensate and liquids	66	67	143	169
Other	1	7	2	8
Total operating revenues	430	568	876	1,303
Transportation and net product costs	(13)	(20)	(27)	(50)
Total operating margin	417	548	849	1,253
Operating expenses:				
Depreciation, depletion and amortization	(131)	(141)	(271)	(299)
Production costs[1]	(44)	(54)	(86)	(114)
Other charges[2]	(2)	4	(11)	1
General and administrative expenses	(37)	(47)	(73)	(91)
Taxes, other than production and income taxes	(1)	(2)	(3)	(5)
Total operating expenses[3]	(215)	(240)	(444)	(508)
Operating income	202	308	405	745
Other income	2	4	3	13
EBIT	$ 204	$ 312	$ 408	$ 758
Volumes, prices and costs per unit:				
Natural gas				
Volumes (MMcf)	61,535	93,241	127,234	191,117
Average realized prices including hedges ($/Mcf)[4]	$ 5.90	$ 5.30	$ 5.75	$ 5.89
Average realized prices excluding hedges ($/Mcf)[4]	$ 5.95	$ 5.34	$ 5.81	$ 6.05
Average transportation costs ($/Mcf)	$ 0.14	$ 0.18	$ 0.15	$ 0.20
Oil, condensate and liquids				
Volumes (MBbls)	1,937	2,577	4,647	6,169
Average realized prices including hedges ($/Bbl)[4]	$ 34.11	$ 26.14	$ 30.86	$ 27.34
Average realized prices excluding hedges ($/Bbl)[4]	$ 34.11	$ 26.86	$ 30.86	$ 28.12
Average transportation costs ($/Bbl)	$ 1.54	$ 0.94	$ 1.35	$ 0.98
Production costs ($/Mcfe)				
Average lease operating costs	$ 0.51	$ 0.38	$ 0.50	$ 0.35
Average production taxes	0.09	0.12	0.06	0.15
Total production cost[1]	$ 0.60	$ 0.50	$ 0.56	$ 0.50
Average general and administrative expenses ($/Mcfe)	$ 0.51	$ 0.43	$ 0.47	$ 0.40
Unit of production depletion cost ($/Mcfe)	$ 1.64	$ 1.22	$ 1.61	$ 1.23

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

(2) Includes restructuring charges and gains on asset sales.

(3) Transportation costs are included in operating expenses on our consolidated statements of income.

(4) Prices are stated before transportation costs.

Quarter Ended June 30, 2004 Compared to Quarter Ended June 30, 2003

EBIT. For the quarter ended June 30, 2004, EBIT was $108 million lower than the same period in 2003. The decrease in EBIT was primarily due to lower production volumes due to normal production declines and disappointing drilling results. Partially offsetting these decreases were higher natural gas and oil prices and lower operating expenses.

Operating Revenues. The following table describes the variance in revenue between the quarters ended June 30, 2004 and 2003 due to: (i) changes in average realized market prices excluding hedges, (ii) changes in production volumes, and (iii) the effects of hedges.

	Variance			
Production Revenue Variance Analysis	**Prices**	**Volumes**	**Hedges**	**Total**
		(In millions)		
Natural gas	$38	$(169)	$—	$(131)
Oil, condensate and liquids	14	(17)	2	(1)
	$52	$(186)	$ 2	(132)
Other				(6)
Total operating revenue variance				$(138)

For the quarter ended June 30, 2004, operating revenues were $138 million lower than in the same period in 2003 due to lower production volumes, partially offset by higher natural gas and oil prices. The decline in production volumes was primarily due to normal production declines in our offshore Gulf of Mexico and Texas Gulf Coast regions and disappointing drilling results.

Average realized natural gas prices for the second quarter of 2004, excluding hedges, were $0.61 per Mcf higher than the same period in 2003, an increase of 11 percent. Our natural gas hedging losses remained unchanged at $4 million in 2003 and 2004. We expect hedging losses to continue in 2004 based on current market prices for natural gas relative to the prices at which our natural gas production is hedged.

Operating Expenses. Total operating expenses were $25 million lower for the second quarter of 2004 as compared to the same period in 2003 primarily due to lower depreciation, depletion, and amortization expenses, lower production costs, and lower general and administrative expenses. We expect to incur higher operating expenses in the fourth quarter of 2004 related to the relocation of our offices in Houston, Texas.

Total depreciation, depletion, and amortization expense decreased by $10 million in the second quarter of 2004 as compared to the same period in 2003. Lower production volumes in 2004 due to the production declines discussed above reduced our depreciation, depletion, and amortization expense by $43 million. Partially offsetting this decrease were higher depletion rates due to higher finding and development costs which contributed an increase of $31 million.

Production costs decreased by $10 million in the second quarter of 2004 as compared to the same period in 2003 primarily due to a decrease in production taxes resulting from high cost gas well tax credits in 2004 and to lower production volumes in 2004 compared to 2003. On a per Mcfe basis, production taxes decreased $0.03 in 2004. However, our total production costs per Mcfe increased $0.10 as lease operating expenses increased $0.13 per Mcfe due to the lower production volumes discussed above.

General and administrative expenses decreased $10 million in the second quarter of 2004 as compared to the same period in 2003. The decrease was primarily due to lower corporate overhead allocations. However, the cost per unit increased $0.08 per Mcfe due to lower production volumes. For the remainder of 2004, we will have higher corporate overhead allocations.

Six Months Ended June 30, 2004 Compared to Six Months Ended June 30, 2003

EBIT. For the six months ended June 30, 2004, EBIT was $350 million lower than the same period in 2003. The decrease in EBIT was primarily due to lower production volumes due to normal production declines, asset sales and disappointing drilling results. Partially offsetting these decreases were lower operating expenses.

Operating Revenues. The following table describes the variance in revenue between the six months ended June 30, 2004 and 2003 due to: (i) changes in average realized market prices excluding hedges, (ii) changes in production volumes, and (iii) the effects of hedges.

	Variance			
Production Revenue Variance Analysis	**Prices**	**Volumes**	**Hedges**	**Total**
		(In millions)		
Natural gas	$(30)	$(386)	$21	$(395)
Oil, condensate and liquids	12	(43)	5	(26)
	$(18)	$(429)	$26	(421)
Other				(6)
Total operating revenue variance				$(427)

For the six months ended June 30, 2004, operating revenues were $427 million lower than the same period in 2003 due to lower production volumes and lower natural gas prices partially offset by a decrease in our hedging losses. The decline in production volumes was primarily due to normal production declines in the offshore Gulf of Mexico and Texas Gulf Coast regions, the sale of properties in New Mexico, Oklahoma, and offshore Gulf of Mexico as well as disappointing drilling results.

Average realized natural gas prices for 2004, excluding hedges, were $0.24 per Mcf lower than the same period in 2003, a decrease of four percent. However, partially offsetting the decrease in revenues due to lower prices were $9 million of hedging losses in 2004 compared to $30 million in 2003 relating to our natural gas hedge positions. We expect hedging losses to continue in 2004 based on current market prices for natural gas relative to the prices at which our natural gas production is hedged.

Operating Expenses. Total operating expenses were $64 million lower in 2004 as compared to the same period in 2003 primarily due to lower depreciation, depletion, and amortization expense, lower production costs, and lower general and administrative expenses. Partially offsetting these lower costs were higher employee severance costs in 2004. We expect to incur additional operating expenses in the fourth quarter of 2004 related to the relocation of our offices in Houston, Texas.

Total depreciation, depletion, and amortization expense decreased by $28 million in 2004 as compared to the same period in 2003. Lower production volumes in 2004 due to asset sales and other production declines discussed above reduced our depreciation, depletion, and amortization expenses by $89 million. Partially offsetting this decrease were higher depletion rates due to higher finding and development costs which contributed an increase of $59 million.

Production costs decreased by $28 million in 2004 as compared to the same period in 2003 primarily due to a decrease in production taxes resulting from high cost gas well tax credits in 2004 and to lower production volumes in 2004 compared to 2003. On a per Mcfe basis, production taxes decreased $0.09 in 2004. However, our total production costs per Mcfe increased $0.06 as lease operating expenses increased $0.15 per Mcfe due to the lower production volumes discussed above.

General and administrative expenses decreased $18 million in 2004 as compared to the same period in 2003. The decrease was primarily due to lower corporate overhead allocations. However, the costs per unit increased $0.07 per Mcfe due to lower production volumes. For the remainder of 2004, we will have higher corporate overhead allocations.

Unregulated Business — Marketing and Trading Segment

Earlier this year, we completed a restatement of our historical financial statements to reflect significant revisions of our proved natural gas and oil reserves and to revise our accounting treatment for the majority of our production hedges. This restatement impacted our 2004 operating results by changing the accounting for many of our natural gas hedging contracts. This change will result in increased earnings volatility in the future related to these derivative contracts as natural gas prices change. For a further discussion of the restatement, refer to our 2003 Annual Report on Form 10-K.

As discussed in our Production segment, in the fourth quarter of 2004, we entered into additional transactions designed to provide protection to El Paso from natural gas price declines in 2005 and 2006. These "put" contracts will provide El Paso with a floor price of $6.00 per MMBtu on 60 TBtu of our Production segment's natural gas production in 2005 and 120 TBtu in 2006. Under these contracts, we will generally have mark-to-market earnings if the current and future price of natural gas declines in any given period and losses if the current and future price of natural gas increases in any given period. We paid a premium of approximately $67 million, or $0.37 per MMBtu, for the transactions and, as a result, will have no future cash margin requirements under the contracts.

Further, we are reviewing a strategy under which certain of our fixed price natural gas derivatives that are currently marked to market would be designated as hedges of the natural gas production in our Production segment. Transactions of this type would generally be treated as hedges for accounting purposes and would have the effect of hedging a portion of the natural gas production volumes in our Production segment at current market prices while reducing our earnings exposure to future natural gas price changes. These derivative hedge designations would have no impact on El Paso's overall cash flow in any period, but would impact the timing of recognizing the changes in the fair value of these derivatives in El Paso's overall operating results.

Our operations primarily consist of the management of our trading portfolio and the marketing of our Production segment's natural gas and oil production. Below are our segment operating results and an analysis of these results for the periods ended June 30:

Marketing and Trading Segment Results

	Quarter Ended June 30,		Six Months Ended June 30,	
	2004	2003	2004	2003
	(In millions)			
Gross margin[1]	$(141)	$(275)	$(300)	$(665)
Operating expenses	(13)	(31)	(29)	(82)
Operating loss	(154)	(306)	(329)	(747)
Other income	2	8	5	15
EBIT	$(152)	$(298)	$(324)	$(732)

(1) Gross margin 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.

Quarter Ended June 30, 2004 Compared to Quarter Ended June 30, 2003

For the quarter ended June 30, 2004, our gross margin improved by $134 million compared to the same period in 2003. This improvement was primarily due to a $208 million decrease in the fair value of our derivatives, principally our natural gas contracts, during 2003 compared to a $95 million decrease in the fair value of our trading positions during 2004. We sell natural gas at a fixed price in many of our trading contracts. The increase in natural gas futures prices in the second quarter of 2003 was more significant than the increase in the second quarter of 2004, resulting in a decrease in the fair value of these derivatives in the second quarter of 2003 that was greater than the same period in 2004. In addition, our Cordova derivative tolling agreement's fair value decreased by $18 million in 2004 compared to a $31 million decrease in 2003. The Cordova power plant sells the power it generates into a power market that was incorporated into the Pennsylvania/New Jersey/Maryland (PJM) power pool in May 2004. We believe that this will improve the Cordova power plant's ability to sell its power into the marketplace and, as a result, will improve the liquidity of our tolling contract with that power plant. This also changed the relationship between the forecasted power and natural gas prices used to determine the fair value of our Cordova tolling agreement. We believe that these changes will improve the overall value of the contract and will reduce the volatility of the fair value of the contract in the future. However, we continue to evaluate the impact that this change will have on the fair value of the Cordova tolling agreement over its term, which extends through 2019.

Also contributing to the improvement in gross margin was $7 million of losses related to the early termination of some of our derivative and non-derivative contracts in 2003, compared to less than $1 million in 2004. In 2003, we were actively liquidating the derivative and non-derivative positions in our trading portfolio. In 2004, we refocused our efforts to manage the existing positions in our portfolio. We may incur future losses on the early termination of our derivative and non-derivative contracts in connection with future asset sales by other segments. We also had settlement losses on non-derivative contracts of $25 million in 2004 compared to $47 million in 2003, which primarily related to demand charges we could not recover on existing transportation contracts. We expect that these demand charges will be lower than those in 2003 as we continue to experience the benefits of previous contract terminations.

For the quarter ended June 30, 2004, our operating expenses decreased by $18 million compared to the same period in 2003. This decrease was primarily due to a $19 million decrease in payroll and other general and administrative expenses, including lower corporate overhead allocations, that resulted from our cost reduction efforts in 2003 and 2004 and a $6 million decrease in operating expenses of our London office, which was closed in 2003. Also contributing to the decrease was $11 million of amortization expense on the Western Energy Settlement obligation that was transferred to our corporate operations in late 2003. This amortization expense was offset by a $25 million reduction in the accrual for the Western Energy Settlement obligation that resulted from the finalization of the payment schedule under the definitive settlement agreement in June 2003.

Six Months Ended June 30, 2004 Compared to Six Months Ended June 30, 2003

For the six months ended June 30, 2004, our gross margin improved by $365 million compared to the same period in 2003. This improvement was primarily due to a $522 million decrease in the fair value of our derivatives, principally our natural gas contracts, during 2003 compared to a $243 million decrease in the fair value of our trading positions during 2004. Included in the 2003 fair value decrease was $81 million of losses incurred on the settlement of our natural gas contracts in the first quarter of 2003. These losses resulted from a high volume of settlements and significant increases in natural gas prices during each of the first three months of 2003. Also contributing to this improvement was $41 million of losses related to the early termination of some of our derivative and non-derivative contracts in 2003, compared to less than $1 million in 2004. Our non-derivative contracts also had settlement losses of $68 million in 2004 compared to $95 million in 2003, which primarily related to demand charges we could not recover on existing transportation contracts. Partially offsetting these improvements was a decrease in our Cordova derivative tolling agreement's fair value of $3 million in 2004 compared to a $7 million increase in 2003.

For the six months ended June 30, 2004, our operating expenses decreased by $53 million compared to the same period in 2003. This decrease was primarily due to a $34 million decrease in payroll and other general and administrative expenses, including lower corporate overhead allocations that resulted from our cost reduction efforts in 2003 and 2004 and a $14 million decrease in operating expenses of our London office, which was closed in 2003. Also contributing to the decrease was $22 million of amortization expense on the Western Energy Settlement obligation that was transferred to our corporate operations in late 2003. This amortization expense was offset by a $25 million reduction in the accrual for the Western Energy Settlement obligation that resulted from the finalization of the payment schedule under the definitive settlement agreement in June 2003.

Unregulated Businesses — Power Segment

Our Power segment has three primary business activities: domestic power plant operations, domestic power contract restructuring activities and international power plant operations. Below are the operating results, a summary of the operating results of each of its activities and an analysis of these results for the periods ended June 30:

Power Segment Results	Quarter Ended June 30, 2004	Quarter Ended June 30, 2003	Six Months Ended June 30, 2004	Six Months Ended June 30, 2003
	(In millions)			
Gross margin[1]	$ 194	$ 255	$ 354	$ 434
Operating expenses	(138)	(187)	(486)	(371)
Operating income (loss)	56	68	(132)	63
Other income (expense)	46	117	95	(74)
EBIT	$ 102	$ 185	$ (37)	$ (11)
Domestic Power				
Domestic power plant operations	7	50	8	(211)
Domestic power contract restructuring business	34	53	(40)	81
International Power				
Brazilian power operations	50	51	(28)	73
Other international power operations	20	40	44	67
Other[2]	(9)	(9)	(21)	(21)
EBIT	$ 102	$ 185	$ (37)	$ (11)

(1) Gross margin consists of revenues from our power plants and the initial net gains and losses incurred in connection with the restructuring of power contracts, as well as the subsequent revenues, cost of electricity purchases and changes in fair value of those contracts. The cost of fuel used in the power generation process is included in operating expenses.

(2) Our other power operations consist of the indirect expenses and general and administrative costs associated with our domestic and international operations, including legal, finance and engineering costs, and the costs of carrying our power turbine inventory. Direct general and administrative expenses of our domestic and international operations are included in EBIT of those operations.

Domestic Power Plant Operations

Quarter Ended June 30, 2004 Compared to Quarter Ended June 30, 2003

Our domestic power plant operations relate to the ownership and operation of power plant assets in the U.S. For the quarter ended June 30, 2004, the EBIT generated by our domestic power plant operations was $43 million lower than the same period in 2003. This decrease was primarily due to impairments of $34 million on our domestic power plants to adjust the carrying value of these plants to the expected sales price in 2004. Also contributing to this decrease was a decrease in operating income in 2004 of $25 million from our East Coast Power facility which was sold during 2003. The majority of our domestic plants were sold in the third quarter of 2004.

Six Months Ended June 30, 2004 Compared to Six Months Ended June 30, 2003

For the six months ended June 30, 2004, the EBIT generated by our domestic power plant operations was $219 million higher than the same period in 2003. This increase was primarily due to a decrease in the amount of impairments in 2004 compared to 2003. In 2003, we recognized a $207 million impairment on our investment in Chaparral and an $86 million loss due to the write-off of receivables as a result of the transfer of our interest in the Milford power facility to the plant's lenders. In 2004, we recognized impairments of $45 million on our domestic power plants to adjust the carrying value of these plants to the expected sales price. Offsetting this net increase was lower operating income in 2004 of $44 million from our East Coast

Power facility which was sold during 2003. The majority of our domestic plants were sold in the third quarter of 2004.

Domestic Power Contract Restructuring Business

Quarter Ended June 30, 2004 Compared to Quarter Ended June 30, 2003

Our domestic power contract restructuring business relates to the continued performance under our previously restructured power contracts. For the quarter ended June 30, 2004, the EBIT generated by our domestic power contract restructuring business was $19 million lower than the same period in 2003. This decrease was primarily due to an increase of $39 million in the fair value of our restructured power contracts in 2004 compared to an increase of $49 million in 2003. This difference was primarily due to lower accretion of the discounted value of these contracts in 2004 compared to 2003 due to the sale of Utility Contract Funding and its restructured power contract in 2004.

Six Months Ended June 30, 2004 Compared to Six Months Ended June 30, 2003

For the six months ended June 30, 2004, the EBIT generated by our domestic power contract restructuring business was $121 million lower than the same period in 2003. This decrease was primarily due to the sale of Utility Contract Funding and its restructured power contract and related debt, which resulted in a $98 million impairment loss during 2004. We also expect to sell our wholly owned subsidiaries, Cedar Brakes I and II which own restructured power contracts that are recorded at fair value. We expect to sell these entities for less than their carrying value, which we anticipate will result in a loss of approximately $220 million in the period the sales agreements are finalized. Our EBIT was also lower in 2004 as compared to 2003 because the fair value of our restructured power contracts increased by $69 million in 2003 compared to $58 million in 2004. This difference was primarily due to lower accretion of the discounted value of these contracts in 2004 compared to 2003 due to the sale of Utility Contract Funding and its restructured power contract in 2004.

International Power Plant Operations

Quarter Ended June 30, 2004 Compared to Quarter Ended June 30, 2003

Brazil. Our Brazilian operations focus on our Macae, Manaus, Rio Negro and Porto Velho power plants. For the quarter ended June 30, 2004, the EBIT generated by our Brazilian power plant operations decreased by $1 million compared to the same period in 2003. This decrease was due primarily to our Porto Velho power plant, which generated operating income of $7 million in 2004 compared to $9 million in 2003. In the fourth quarter of 2004, the Porto Velho power plant experienced an equipment failure that will temporarily reduce the gross capacity of the plant from 404 MW to 284 MW. We expect that this failure will reduce our EBIT for the fourth quarter of 2004 and first six months of 2005.

Other International. For the quarter ended June 30, 2004, the EBIT generated by our other international power operations was $20 million lower than the same period in 2003. The decrease was primarily due to a $24 million gain on the sale of our CAPSA/CAPEX investments in Argentina in 2003. Also contributing to the decrease was $5 million of EBIT generated by our investments in Mexico in 2003, the majority of which were transferred to the Pipelines segment effective January 1, 2004. Partially offsetting these decreases was an increase of $8 million in the equity earnings from two of our Asian equity investments in 2004 when compared to the same period in 2003.

Six Months Ended June 30, 2004 Compared to Six Months Ended June 30, 2003

Brazil. During the first quarter of 2003, we conducted a majority of our power plant operations in Brazil through Gemstone, an unconsolidated joint venture. In the second quarter of 2003, we acquired the joint venture partner's interest in Gemstone and began consolidating Gemstone's debt and its interests in the Macae and Porto Velho power plants. As a result, our operating results during the first quarter of 2003 include the equity earnings we earned from Gemstone, while our consolidated operating results for the second quarter of

2003 and the first six months of 2004 include the revenues, expenses and equity earnings from Gemstone's assets.

For the six months ended June 30, 2004, the EBIT loss generated by our Brazilian power plant operations was $28 million compared to EBIT of $73 million in the same period in 2003. Our 2004 EBIT loss was primarily due to $135 million of impairments of the Manaus and Rio Negro power plants due to events in the first quarter of 2004 that may make it difficult to extend their power sales agreements that expire in 2005 and 2006. These losses were partially offset by $86 million of operating income from our Macae power plant and $14 million from our Porto Velho power plant in 2004.

Our 2003 EBIT included $17 million of equity earnings from Gemstone, which primarily included the operating results from the Macae and Porto Velho power plants above and the cost of the debt held by Gemstone during the first three months of 2003. During the second quarter of 2003, our Macae and Porto Velho power plants generated operating income of $41 million and $9 million.

Other International. For the six months ended June 30, 2004, the EBIT generated by our other international power operations was $23 million lower than the same period in 2003. The decrease was primarily due to a $24 million gain on the sale of our CAPSA/CAPEX investments in Argentina in 2003. Also contributing to the decrease was $8 million of EBIT generated by our investments in Mexico in 2003, the majority of which were transferred to the Pipelines segment effective January 1, 2004. Partially offsetting these decreases was an increase of $9 million in the equity earnings from two of our Asian equity investments in 2004 when compared to the same period in 2003.

We are currently in the process of selling a number of our domestic and international power assets. As these sales occur and as sales agreements are negotiated and approved, it is possible that impairments of these assets may occur, and these impairments may be material.

Unregulated Businesses — Field Services Segment

Our Field Services segment conducts our midstream activities which includes holding our general and limited partner interests in GulfTerra, a publicly traded master limited partnership, and gathering and processing assets. Following the sales of substantially all of our remaining interests in GulfTerra as well as our south Texas processing plants to Enterprise as part of a merger transaction between GulfTerra and Enterprise described further below, the majority of our gathering and processing business will be conducted through our remaining ownership interests in the merged partnership.

During 2003, the primary source of earnings in our Field Services segment was from our equity investment in GulfTerra. Our sale of an effective 50 percent interest in GulfTerra's general partner in December 2003 as well as the completion of the sale in September 2004 of our remaining interest in the general partner of GulfTerra (upon which we received cash and a 9.9 percent interest in the general partner of Enterprise Products GP, LLC) has and will continue to result in lower equity earnings in 2004. Additionally, prior to these sales, we received management fees under an agreement to provide operational and administrative services to the partnership. Upon the closing of the merger of GulfTerra and Enterprise, these fees and many of the internal costs of providing these management services were eliminated. We have also agreed to provide a total of $45 million in payments to Enterprise during the three years after the merger becomes effective.

We are reimbursed for costs paid directly by us on the partnership's behalf. For the six months ended June 30, 2004 and 2003, we were reimbursed for expenses incurred on behalf of the partnership of approximately $45 million and $46 million, of which $23 and $22 were incurred in the second quarter of 2004 and 2003.

During 2004, our earnings and cash distributions received from GulfTerra were as follows:

	Quarter Ended June 30,		Six Months Ended June 30,	
	Earnings Recognized	Cash Received	Earnings Recognized	Cash Received
	(In millions)			
General partner's share of distributions	$21	$22	$42	$43
Proportionate share of income available to common unit holders	3	7	8	14
Series C units	5	8	10	16
Gains on issuance by GulfTerra of its common units	—	—	3	—
	$29	$37	$63	$73

For a discussion of our ownership interests in GulfTerra and our activities with the partnership, see Item 1, Financial Statements, Note 16. For a further discussion of the business activities of our Field Services segment, see our 2003 Annual Report on Form 10-K. Below are the operating results and analysis of these results for our Field Services segment for the periods ended June 30:

Field Services Segment Results	Quarter Ended June 30, 2004	Quarter Ended June 30, 2003	Six Months Ended June 30, 2004	Six Months Ended June 30, 2003
	(In millions, except volumes and prices)			
Processing and gathering gross margins[1]	$ 44	$ 29	$ 89	$ 76
Operating expenses	(37)	(44)	(72)	(91)
Operating income (loss)	7	(15)	17	(15)
Other income (expense)	20	(41)	46	(14)
EBIT	$ 27	$ (56)	$ 63	$ (29)
Volumes and Prices:				
Processing				
Volumes (inlet BBtu/d)	3,135	3,202	3,189	3,254
Prices ($/MMBtu)	$ 0.12	$ 0.08	$ 0.12	$ 0.09
Gathering				
Volumes (BBtu/d)	251	444	218	510
Prices ($/MMBtu)	$ 0.11	$ 0.18	$ 0.11	$ 0.20

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

For the quarter and six months ended June 30, 2004, our EBIT was $83 million and $92 million higher than the same periods in 2003. Below is a summary of significant factors affecting EBIT.

	Quarter Ended June 30,				Six Months Ended June 30,			
	Gross Margin	Operating Expense	Other Income	EBIT Impact	Gross Margin	Operating Expense	Other Income	EBIT Impact
	Favorable (Unfavorable) (In millions)							
Higher NGL Prices								
Processing	$11	$—	$ —	$ 11	$ 24	$ —	$ —	$ 24
Javelina equity investment	—	—	4	4	—	—	8	8
Lower fuel and transportation costs	4	—	—	4	9	—	—	9
Asset sales								
Impact of reduced operations	(6)	11	—	5	(20)	26	—	6
Net gains recorded in 2003	—	(6)	—	(6)	—	(5)	—	(5)
Impairments[1]	—	—	80	80	—	—	80	80
Investment in GulfTerra								
Higher SAB 51 gains in 2003	—	—	(12)	(12)	—	—	(9)	(9)
Minority interest	—	—	(11)	(11)	—	—	(21)	(21)
Other	6	2	—	8	—	(2)	2	—
	$15	$ 7	$ 61	$ 83	$ 13	$ 19	$ 60	$ 92

(1) Our equity investments in Dauphin Island and Mobile Bay were impaired in 2003 based on anticipated losses on the sales of these investments. These sales were completed in the third quarter of 2004.

Processing margins increased primarily due to the higher NGL prices relative to natural gas prices, which caused us to maximize the amount of NGLs that were extracted by our natural gas processing facilities in south Texas at an increased margin per unit. In addition, margin attributable to the marketing of NGLs increased as a result of lower fuel and transportation costs and the availability of an NGL pipeline system in 2004 to move our liquids to the Mt. Belvieu market. In the second quarter of 2003, the NGL pipeline system to Mt. Belvieu was down for maintenance. In the third quarter of 2004 we expect to incur an impairment charge of approximately $13 million on our Indian Springs natural gas gathering and processing assets. These assets were approved for sale by our Board of Directors in August 2004.

Corporate, Net

Our corporate operations include our general and administrative functions as well as a telecommunications business and various other contracts and assets, including financial services and LNG and related items, all of which are immaterial to our results in 2004. During the first quarter of 2004, we reclassified our petroleum ship charter operations from discontinued operations to our continuing corporate operations. Our operating results for all periods reflect this change.

For the periods ended June 30, 2004, EBIT in our corporate operations were higher than the same period in 2003 due to the following:

	Increase in EBIT for quarter ended June 30, 2004 compared to 2003	Increase in EBIT for six months ended June 30, 2004 compared to 2003
	(In millions)	
Lower impairments on the assets in our telecommunications business	$ 396	$ 412
Lower foreign currency losses on Euro-denominated debt	51	96
Lower impairments and contract terminations in our LNG business	20	85
Lower losses on early extinguishment of debt	37	37
Lower employee severance, retention and transition costs	13	29
Other increases	7	39
Total increase in EBIT	$ 524	$ 698

We have a number of pending litigation matters, including shareholder and other lawsuits filed against us. We are currently evaluating each of these suits as to their merits and our defenses. Adverse rulings against us and/or unfavorable settlements related to these and other legal matters would impact our future results. Additionally, during 2004, we hedged an additional €100 million of our Euro-denominated debt, which we expect will continue to reduce our exposure to foreign currency fluctuations. As discussed in Item 1, Financial Statements, Note 5, we incurred relocation charges of approximately $30 million in the third quarter of 2004 related to the consolidation of our Houston-based operations. We estimate the total charge will be approximately $80 million to $100 million.

Interest and Debt Expense

Interest and debt expense for the quarter and six months ended June 30, 2004, was $53 million and $44 million lower than the same periods in 2003. Below is an analysis of our interest expense for the periods ended June 30:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2004	2003	2004	2003
	(In millions)			
Long-term debt, including current maturities	$383	$415	$780	$786
Revolving credit facilities	27	35	55	55
Other interest	8	18	16	46
Capitalized interest	(8)	(5)	(18)	(10)
Total interest and debt expense	$410	$463	$833	$877

Quarter and Six Months Ended June 30, 2004 Compared to Quarter and Six Months Ended June 30, 2003

Interest expense on long-term debt decreased due to retirements of debt during 2003 and the first and second quarters of 2004, net of issuances. This decrease in interest expense was partially offset by the reclassification of our preferred securities as long-term financing obligations and recording the preferred returns on these securities as interest expense. For further information of this reclassification, see the discussion below. Interest expense on our revolving credit facility decreased due to a payment of $250 million on the revolver during the first quarter of 2004. Partially offsetting this decrease were higher commitment fees on letters of credit in the second quarter of 2004 as compared to 2003. Other interest decreased due to retirements and consolidations of other financing obligations. Finally, capitalized interest for the quarter and six months ended June 30, 2004, was higher than the same period in 2003 primarily due to higher average interest rates in 2004 than in 2003.

Distributions on Preferred Interests of Consolidated Subsidiaries

Distributions on preferred interests of consolidated subsidiaries for the quarter and six months ended June 30, 2004 were $11 million and $26 million lower than the same periods in 2003 primarily due to the refinancing and redemption of our Clydesdale financing arrangement, the redemptions of the preferred stock on two of our subsidiaries, Trinity River and Coastal Securities, and the reclassification of our Coastal Finance I and Capital Trust I mandatorily redeemable preferred securities to long-term financing obligations as a result of the adoption of SFAS No. 150 in 2003. Based on this reclassification, we began recording the preferred returns on these securities as interest expense rather than as distributions of preferred interests. The decrease was also due to the impact of the consolidations of Chaparral and Gemstone as a result of our acquisitions of these investments. Our remaining balance of preferred interests as of June 30, 2004 primarily consists of $300 million of preferred stock of our consolidated subsidiary, El Paso Tennessee Pipeline Co.

Income Taxes

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

	Quarter Ended June 30,		Six Months Ended June 30,	
	2004	2003	2004	2003
	(In millions, except for rates)			
Income taxes	$37	$(410)	$ 47	$(513)
Effective tax rate	45%	58%	(940)%	50%

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

- state income taxes, net of federal income tax benefit;
- foreign income taxed at different rates, including impairments of certain of our foreign investments;
- earnings from unconsolidated affiliates where we anticipate receiving dividends; and
- non-deductible dividends on the preferred stock of subsidiaries.

For the year ended December 31, 2004, our effective tax rate will be significantly different from the statutory rate of 35 percent because of the completion of the merger between GulfTerra and Enterprise in September 2004. The sale of our interests in GulfTerra associated with the merger will result in a significant tax gain (versus a much lower book gain) and significant tax expense due to the non-deductibility of goodwill written off as a result of the transaction. We believe the impact of this non-deductible goodwill will increase our tax expense (or reduce our tax benefit) by approximately $139 million.

Proposed tax legislation is being considered in Congress which would disallow deductions for certain settlements made to or on behalf of governmental entities. If enacted, this tax legislation could impact the deductibility of the Western Energy Settlement and could result in a write-off of some or all of the associated tax assets. In such event, our tax expense would increase. Our total tax assets related to the Western Energy Settlement were approximately $400 million as of June 30, 2004.

For a further discussion of our effective tax rates, see Item 1, Financial Statements, Note 7.

Discontinued Operations

The loss from our discontinued operations for the second quarter of 2004 was $29 million compared to a loss of $939 million for the same period of 2003. The loss in 2004 related to impairment charges on our remaining Canadian production operations that were discontinued during the second quarter of 2004. The loss in 2003 was primarily due to impairments at our Aruba refining facility that was approved for sale by our Board of Directors during the second quarter of 2003.

For the six months ended June 30, 2004, the loss from our discontinued operations was $138 million compared to a loss of $1,154 million during the same period in 2003. In 2004, $69 million of losses from discontinued operations related to our Canadian and certain other international production operations, primarily from impairments, and $69 million was from our petroleum markets activities, primarily related to losses on the completed sales of our Eagle Point and Aruba refineries along with other operational and severance costs. The losses in 2003 related to impairment charges on our Aruba and Eagle Point refineries and on chemical assets, all as a result of the decision by our Board of Directors to exit and sell these businesses.

Commitments and Contingencies

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

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

We have made statements in this document that constitute forward-looking statements, as that term is defined in the Private Securities Litigation Reform Act of 1995. 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;
- credit ratings;
- 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 2003 Annual Report on Form 10-K filed with the Securities and Exchange Commission on September 30, 2004.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

This information updates, and you should read it in conjunction with, information disclosed in our 2003 Annual Report on Form 10-K, 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 2003 Annual Report on Form 10-K, 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 $32 million as of June 30, 2004 and $34 million as of December 31, 2003, and represents our potential one-day unfavorable impact on the fair values of our trading contracts.

Interest Rate Risk

As of June 30, 2004 and December 31, 2003, we had $0.7 billion and $1.7 billion of third party long-term restructured power purchase and power supply derivative contracts. In the second quarter of 2004, we sold one of the contracts held by Utility Contract Funding, which had a fair value of $865 million as of December 31, 2003. This sale and the planned sale of Cedar Brakes I and II, which hold two of our power derivative contracts, will substantially reduce our exposure to interest rate risk related to these contracts.

Item 4. Controls and Procedures

During 2003, we initiated a project to ensure compliance with Section 404 of the Sarbanes-Oxley Act of 2002 (SOX), which will apply to us at December 31, 2004. This project entailed a detailed review and documentation of the processes that impact the preparation of our financial statements, an assessment of the risks that could adversely affect the accurate and timely preparation of those financial statements, and the identification of the controls in place to mitigate the risks of untimely or inaccurate preparation of those financial statements. Following the documentation of these processes, we initiated an internal review or ''walk-through'' of these financial processes by the financial management responsible for those processes to evaluate the design effectiveness of the controls identified to mitigate the risk of material misstatements occurring in our financial statements. We also initiated a detailed process to evaluate the operating effectiveness of our controls over financial reporting. This process involves testing the controls for effectiveness, including a review and inspection of the documentary evidence supporting the operation of the controls on which we are placing reliance.

In September 2004, we completed investigations surrounding matters that gave rise to a restatement of our historical financial statements for the period from 1999 to 2002 and the first nine months of 2003. These investigations identified a number of internal control weaknesses which we reported as material control weaknesses in our Annual Report on Form 10-K.

The following are the internal control deficiencies related to the restatements of our historical financial statements, and those identified as a result of our SOX implementation which we have previously disclosed:

- A weak control environment surrounding the booking of proved natural gas and oil reserves in our Production segment;
- Inadequate controls over access to our proved natural gas and oil reserve system;
- Inadequate documentation of policies and procedures related to booking proved natural gas and oil reserves;
- Inadequate documentation of accounting conclusions related to complex accounting standards;
- Lack of formal documentation and communication of policies and procedures with respect to accounting matters;
- Ineffective monitoring activities to ensure compliance with existing policies, procedures and accounting conclusions (in some cases as a result of inadequate staffing);
- Lack of formal evidence to substantiate monitoring activities were adequately performed (e.g. monitoring activities, such as meetings and report reviews, were not always documented in a way to objectively confirm the monitoring activities occurred);
- Inadequate change management and security access to our information systems (e.g., program developers were allowed to migrate system changes into production and passwords for some of our applications did not adhere to the corporate policy for passwords);
- Lack of segregation of duties related to manual journal entry preparation and procurement activities (e.g., our financial accounting system was not designed to prevent the same person from posting an entry that prepared the entry and a buyer of goods could also receive for the goods); and
- Untimely preparation and review of volume and account reconciliations.

We have communicated to our Audit Committee and to our external auditors the deficiencies identified to date in our internal controls over financial reporting as well as the remediation efforts that we have underway. Our management, with the oversight of our Audit Committee, is committed to effectively remediate known deficiencies as expeditiously as possible and continues its extensive efforts to comply with

Section 404 of SOX by December 31, 2004. Consequently, we have made the following changes to our internal controls during 2004:

- Added members to our Board of Directors, including our Audit Committee, and our executive management team with extensive experience in the natural gas and oil industry;
- Formed an internal committee to provide oversight of the proved natural gas and oil reserve estimation process, which is staffed with appropriate technical, financial reporting and legal expertise;
- Continued the use of an independent third-party reserve engineering firm, selected by and reporting annually to the Audit Committee of the Board of Directors, to perform an independent assessment of our proved natural gas and oil reserves;
- Formed a centralized proved natural gas and oil reserve evaluation and reporting function, staffed primarily with newly hired personnel that have extensive industry experience, that is separate from the operating divisions and reports to the president of Production and Non-regulated Operations;
- Restricted security access to the proved natural gas and oil reserve system to the centralized reserve reporting staff;
- Revised our documentation of procedures and controls for estimating proved natural gas and oil reserves;
- Enhanced internal audit reviews to monitor booking of proved natural gas and oil reserves;
- Implemented standard information system policies and procedures to enforce change management and segregation of responsibilities when migrating programming changes to production and strengthened security policies and procedures around passwords for applications and databases;
- Modified systems and procedures to ensure appropriate segregation of responsibilities for manual journal entry preparation and procurement activities;
- Formalized our account reconciliation policy and completed all material account reconciliations; and
- Developed and implemented formal training to educate company personnel on management's responsibilities mandated by SOX Section 404, the components of the internal control framework on which we rely and its relationship to our company values including accountability, stewardship, integrity and excellence.

We are in the process of implementing the following changes to our internal controls, which we expect to have implemented by December 31, 2004:

- Improved training regarding SEC guidelines for booking proved natural gas and oil reserves;
- Formal communication of procedures for documenting accounting conclusions involving interpretation of complex accounting standards, including identification of critical factors that support the basis for our conclusion;
- Evaluation, formalization and communication of required policies and procedures;
- Improved monitoring activities to ensure compliance with policies, procedures and accounting conclusions; and
- Review of the adequacy, proficiency and training of our finance and accounting staff.

Many of the deficiencies in our internal controls that we have identified are likely the result of significant changes the company has undergone during the past five years as a result of major acquisitions and reorganizations. As we continue our SOX Section 404 compliance efforts, including the testing of the effectiveness of our internal controls, we may identify additional deficiencies in our system of internal controls that either individually or in the aggregate may represent a material weakness requiring additional remediation efforts.

We did not make any changes to our internal controls over financial reporting during the six months ended June 30, 2004, that have had a material adverse affect or are reasonably likely to have a material adverse affect on our internal controls over financial reporting.

We also reviewed our overall disclosure controls and procedures for the quarter ended June 30, 2004. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Securities Exchange Act of 1934 is accumulated and communicated to our management, including our principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

As a result of the internal control deficiencies described above, we concluded that our disclosure controls and procedures were not effective at June 30, 2004. However, we expanded our procedures to include additional analysis and other post-closing procedures to ensure that the disclosure controls and procedures over the preparation of these financial statements were effective.

PART II — OTHER INFORMATION

Item 1. Legal Proceedings

See Part I, Item 1, Note 12, which is incorporated herein by reference. Additional information about our legal proceedings can be found in Part I, Item 3 of our Annual Report on Form 10-K filed with the Securities and Exchange Commission on September 30, 2004.

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

We held our annual meeting of stockholders on November 18, 2004. Proposals presented for a stockholders' vote included the election of twelve directors, ratification of the appointment of PricewaterhouseCoopers LLP as independent certified public accountants for the fiscal year 2004, and two stockholder proposals.

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

Nominee	For	Withheld
John M. Bissell	484,639,859	101,741,034
Juan Carlos Braniff	485,212,690	101,168,202
James L. Dunlap	503,715,688	82,665,204
Douglas L. Foshee	564,694,430	21,686,462
Robert W. Goldman	503,086,283	83,294,609
Anthony W. Hall, Jr.	490,112,165	96,268,727
Thomas R. Hix	563,913,752	22,467,140
William H. Joyce	564,050,375	22,330,518
Ronald L. Kuehn, Jr.	483,437,462	102,943,431
J. Michael Talbert	503,779,161	82,601,731
John L. Whitmire	502,420,108	83,960,784
Joe B. Wyatt	487,881,511	98,499,382

The appointment of PricewaterhouseCoopers LLP as El Paso's independent certified public accountants for the fiscal year 2004 was ratified with the following voting results:

	For	Against	Abstain
Proposal to ratify the appointment of PricewaterhouseCoopers LLP as independent certified public accountants	512,328,324	68,245,737	5,806,831

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

Two proposals submitted by stockholders were presented for a stockholder vote. One proposal called for stockholder approval of expensing the costs of all future stock options in the annual income statement. The second proposal called for stockholder approval regarding Commonsense Executive Compensation. The first stockholder proposal was approved and the second stockholder proposal was not approved with the following voting results:

	For	Against	Abstain
Stockholder proposal regarding expensing stock options	303,127,387	125,027,119	12,236,275
Stockholder proposal regarding Commonsense Executive Compensation	50,700,938	379,536,201	10,153,643

Item 5. Other Information

None.

Item 6. Exhibits

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

Exhibit Number	Description
*31.A	Certification of Chief Executive Officer pursuant to sec. 302 of the Sarbanes-Oxley Act of 2002.
*31.B	Certification of Chief Financial Officer pursuant to sec. 302 of the Sarbanes-Oxley Act of 2002.
*32.A	Certification of Chief Executive Officer pursuant to 18 U.S.C. sec. 1350 as adopted pursuant to sec. 906 of the Sarbanes-Oxley Act of 2002.
*32.B	Certification of Chief Financial Officer pursuant to 18 U.S.C. sec. 1350 as adopted pursuant to sec. 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, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

EL PASO CORPORATION

Date: November 23, 2004

/s/ D. DWIGHT SCOTT

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

Date: November 23, 2004

/s/ JEFFREY I. BEASON

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