# 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, 2006**

**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**<br>(State or Other Jurisdiction of Incorporation or Organization) | **76-0568816**<br>(I.R.S. Employer Identification No.) |
| **El Paso Building**<br>**1001 Louisiana Street**<br>**Houston, Texas**<br>(Address of Principal Executive Offices) | **77002**<br>(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 a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):
Large accelerated filer ☑ Accelerated filer ☐ Non-accelerated filer ☐

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

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

Common stock, par value $3 per share. Shares outstanding on August 3, 2006: 695,949,316

**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 |
| Bcfe | = billion cubic feet of natural gas equivalents | MMcfe | = million cubic feet of natural gas equivalents |
| LNG | = liquefied natural gas | MW | = megawatt |
| MBbls | = thousand barrels | NGL | = natural gas liquids |
| Mcf | = thousand cubic feet | TBtu | = trillion British thermal units |

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

When we refer to "us", "we", "our", "ours", "the company" 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)**

| | Quarters Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2006 | 2005 | 2006 | 2005 |
| Operating revenues | $1,214 | $1,169 | $2,745 | $2,257 |
| Operating expenses | | | | |
| Cost of products and services | 85 | 54 | 146 | 148 |
| Operation and maintenance | 385 | 385 | 719 | 796 |
| Depreciation, depletion and amortization | 278 | 284 | 550 | 553 |
| Loss on long-lived assets | — | — | — | 7 |
| Taxes, other than income taxes | 70 | 56 | 134 | 121 |
| | 818 | 779 | 1,549 | 1,625 |
| Operating income | 396 | 390 | 1,196 | 632 |
| Earnings (losses) from unconsolidated affiliates | 52 | (19) | 97 | 171 |
| Other income, net | 39 | 67 | 82 | 98 |
| Interest and debt expense | (332) | (333) | (680) | (676) |
| Preferred interests of consolidated subsidiaries | — | (3) | — | (9) |
| Income before income taxes | 155 | 102 | 695 | 216 |
| Income taxes | 2 | 35 | 167 | 36 |
| Income from continuing operations | 153 | 67 | 528 | 180 |
| Discontinued operations, net of income taxes | (3) | (305) | (22) | (312) |
| Net income (loss) | 150 | (238) | 506 | (132) |
| Preferred stock dividends | 9 | 8 | 19 | 8 |
| Net income (loss) available to common stockholders | $ 141 | $ (246) | $ 487 | $ (140) |
| Earnings (losses) per common share | | | | |
| Basic | | | | |
| Income from continuing operations | $ 0.22 | $ 0.09 | $ 0.77 | $ 0.27 |
| Discontinued operations, net of income taxes | (0.01) | (0.47) | (0.03) | (0.49) |
| Net income (loss) | $ 0.21 | $(0.38) | $ 0.74 | $(0.22) |
| Diluted | | | | |
| Income from continuing operations | $ 0.21 | $ 0.09 | $ 0.73 | $ 0.26 |
| Discontinued operations, net of income taxes | — | (0.47) | (0.03) | (0.45) |
| Net income (loss) | $ 0.21 | $(0.38) | $ 0.70 | $(0.19) |
| 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, 2006 | December 31, 2005 |
|---|---|---|
| **ASSETS** | | |
| Current assets | | |
| Cash and cash equivalents | $ 1,762 | $ 2,132 |
| Accounts and notes receivable | | |
| Customers, net of allowance of $50 in 2006 and $67 in 2005 | 690 | 1,115 |
| Affiliates | 89 | 58 |
| Other | 411 | 141 |
| Assets from price risk management activities | 275 | 641 |
| Margin and other deposits held by others | 391 | 1,124 |
| Assets related to discontinued operations | 38 | 230 |
| Deferred income taxes | 263 | 396 |
| Other | 310 | 348 |
| Total current assets | 4,229 | 6,185 |
| Property, plant and equipment, at cost | | |
| Pipelines | 20,509 | 19,965 |
| Natural gas and oil properties, at full cost | 16,197 | 15,738 |
| Other | 626 | 651 |
| | 37,332 | 36,354 |
| Less accumulated depreciation, depletion and amortization | 17,977 | 17,567 |
| Total property, plant and equipment, net | 19,355 | 18,787 |
| Other assets | | |
| Investments in unconsolidated affiliates | 2,102 | 2,473 |
| Assets from price risk management activities | 689 | 1,368 |
| Other | 2,402 | 3,025 |
| | 5,193 | 6,866 |
| Total assets | $28,777 | $31,838 |

See accompanying notes.

## EL PASO CORPORATION

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

| | June 30, 2006 | December 31, 2005 |
|---|---|---|
| **LIABILITIES AND STOCKHOLDERS' EQUITY** | | |
| Current liabilities | | |
| Accounts payable | | |
| Trade | $ 533 | $ 864 |
| Affiliates | 6 | 10 |
| Other | 447 | 540 |
| Short-term financing obligations, including current maturities | 838 | 986 |
| Liabilities from price risk management activities | 475 | 1,418 |
| Liabilities related to discontinued operations | 24 | 420 |
| Margin deposits held by us | 456 | 497 |
| Accrued interest | 281 | 290 |
| Other | 1,027 | 687 |
| Total current liabilities | 4,087 | 5,712 |
| Long-term financing obligations, less current maturities | 15,374 | 17,023 |
| Other | | |
| Liabilities from price risk management activities | 1,173 | 2,005 |
| Deferred income taxes | 1,653 | 1,405 |
| Other | 1,921 | 2,273 |
| | 4,747 | 5,683 |
| Commitments and contingencies | | |
| Securities of subsidiaries | 31 | 31 |
| Stockholders' equity | | |
| Preferred stock, par value $0.01 per share; authorized 50,000,000 shares; issued 750,000, 4.99% convertible perpetual shares; stated at liquidation value | 750 | 750 |
| Common stock, par value $3 per share; authorized 1,500,000,000 shares; issued 704,226,042 shares in 2006 and 667,082,043 shares in 2005 | 2,113 | 2,001 |
| Additional paid-in capital | 4,860 | 4,592 |
| Accumulated deficit | (2,909) | (3,415) |
| Accumulated other comprehensive loss | (77) | (332) |
| Treasury stock (at cost); 8,377,009 shares in 2006 and 7,620,272 shares in 2005 | (199) | (190) |
| Unamortized compensation | — | (17) |
| Total stockholders' equity | 4,538 | 3,389 |
| Total liabilities and stockholders' equity | $28,777 | $31,838 |

See accompanying notes.

## EL PASO CORPORATION

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

| | Six Months June 30, 2006 | Six Months June 30, 2005 |
|---|---|---|
| Cash flows from operating activities | | |
| Net income (loss) | $ 506 | $ (132) |
| Loss from discontinued operations, net of income taxes | (22) | (312) |
| Net income from continuing operations | 528 | 180 |
| Adjustments to reconcile net income to net cash from operating activities | | |
| Depreciation, depletion and amortization | 550 | 553 |
| Loss on long-lived assets | — | 7 |
| Earnings (losses) from unconsolidated affiliates, adjusted for cash distributions | 15 | (24) |
| Deferred income taxes | 135 | 106 |
| Other non-cash items | 48 | 16 |
| Change in margin and other deposits | 692 | (38) |
| Other asset and liability changes | (547) | (770) |
| Cash provided by continuing operations | 1,421 | 30 |
| Cash provided by (used in) discontinued operations | 1 | (20) |
| Net cash provided by operating activities | 1,422 | 10 |
| Cash flows from investing activities | | |
| Capital expenditures | (1,024) | (817) |
| Net proceeds from the sale of assets and investments | 475 | 834 |
| Proceeds from settlement of a foreign currency derivative | — | 131 |
| Cash paid for acquisitions, net of cash acquired | — | (178) |
| Other | 22 | 52 |
| Cash provided by (used in) continuing operations | (527) | 22 |
| Cash provided by discontinued operations | 355 | 128 |
| Net cash provided by (used in) investing activities | (172) | 150 |
| Cash flows from financing activities | | |
| Payments to retire long-term debt and other financing obligations | (1,820) | (1,512) |
| Net proceeds from the issuance of long-term debt and other financing obligations | — | 458 |
| Dividends paid | (71) | (51) |
| Net proceeds from issuance of common stock | 500 | — |
| Net proceeds from issuance of preferred stock | — | 723 |
| Redemption of preferred stock of subsidiary | — | (300) |
| Contributions from discontinued operations | 126 | 57 |
| Other | 1 | (4) |
| Cash used in continuing operations | (1,264) | (629) |
| Cash used in discontinued operations | (356) | (108) |
| Net cash used in financing activities | (1,620) | (737) |
| Change in cash and cash equivalents | (370) | (577) |
| Cash and cash equivalents | | |
| Beginning of period | 2,132 | 2,117 |
| End of period | $ 1,762 | $ 1,540 |

See accompanying notes.

## EL PASO CORPORATION

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

| | Quarters Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | **2006** | **2005** | **2006** | **2005** |
| Net income (loss) | $150 | $(238) | $506 | $(132) |
| Foreign currency translation adjustments (net of income taxes of less than $1 in 2006 and $6 and $7 in 2005) | (1) | (4) | 2 | 7 |
| Unrealized net gains (losses) from cash flow hedging activity | | | | |
| Unrealized mark-to-market gains (losses) arising during period (net of income taxes of $47 and $123 in 2006 and $13 and $89 in 2005) | 88 | 17 | 219 | (172) |
| Reclassification adjustments for changes in initial value to the settlement date (net of income taxes of $4 and $15 in 2006 and $1 and $12 in 2005) | 5 | 2 | 25 | (19) |
| Change in unrealized gains on available for sale securities, net of reclassification adjustments (net of income tax of $3 and $5 in 2006) | (6) | — | 9 | — |
| Other comprehensive income (loss) | 86 | 15 | 255 | (184) |
| Comprehensive income (loss) | $236 | $(223) | $761 | $(316) |

See accompanying notes.

# EL PASO CORPORATION

## NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
## (Unaudited)

### 1. Basis of Presentation and Significant Accounting Policies

*Basis of Presentation*

We prepared this Quarterly Report on Form 10-Q under the rules and regulations of the United States Securities and Exchange Commission. Because this is an interim period filing presented using a condensed format, it does not include all of the disclosures required by United States generally accepted accounting principles. You should read this Quarterly Report on Form 10-Q along with our Current Report on Form 8-K dated May 12, 2006, which updated the financial information originally presented in our 2005 Form 10-K to reclassify our Macae power facility in Brazil as a discontinued operation, and which contains a summary of our significant accounting policies and other disclosures. The financial statements as of June 30, 2006, and for the quarters and six months ended June 30, 2006 and 2005, are unaudited. We derived the condensed balance sheet as of December 31, 2005, from the audited balance sheet filed in our Current Report on Form 8-K dated May 12, 2006. 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 our results of operations for the entire year. Additionally, our financial statements for prior periods include reclassifications that were made to conform to the current period presentation. Those reclassifications did not impact our reported net income or stockholders' equity.

*Significant Accounting Policies*

Our significant accounting policies are discussed in our Current Report on Form 8-K dated May 12, 2006. The information below provides updating information, disclosures where these policies have changed and required interim disclosures with respect to those policies.

*Stock Based Compensation.* In December 2004, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards (SFAS) No. 123(R), *Share-Based Payment.* This standard and its related interpretations amend previous stock-based compensation guidance and require companies to measure all employee stock-based compensation awards at fair value on the date they are granted to employees and recognize compensation cost in their financial statements over the requisite service period. Effective January 1, 2006, we adopted the provisions of SFAS No. 123(R) for stock based compensation awards granted on or after that date and for unvested awards outstanding at that date using the modified prospective application method. Under this method, prior period results were not restated. Prior to January 1, 2006, we accounted for these plans using the intrinsic value method under the provisions of Accounting Principles Board (APB) Opinion No. 25, *Accounting for Stock Issued to Employees,* and its related interpretations, and did not record compensation expense on stock options that were granted at the market value of the stock on the date of grant. The adoption of SFAS No. 123(R) did not have a material impact to our financial statements as of and for the quarter and six months ended June 30, 2006. For additional information on the adoption of this standard, see Note 12.

*Accounting for Pipeline Integrity Costs.* As of January 1, 2006, we had adopted an accounting release issued by the Federal Energy Regulatory Commission (FERC) that requires us to begin expensing certain costs our interstate pipelines incur related to their pipeline integrity programs. Prior to adoption, we capitalized these costs as part of our property, plant and equipment. During the quarter and six months ended June 30, 2006, we expensed approximately $6 million and $7 million as a result of the adoption of this accounting release, which was less than $0.01 per basic and fully diluted share for both the quarter and six month periods ended June 30, 2006. We anticipate we will expense additional costs of approximately $21 million for the remainder of the year.

*New Accounting Pronouncements Issued But Not Yet Adopted*

*Accounting for Uncertainty in Income Taxes.* In July 2006, the FASB issued FASB Interpretation (FIN) No. 48, *Accounting for Uncertainty in Income Taxes.* FIN No. 48 clarifies SFAS No. 109, *Accounting for Income Taxes,* and requires us to evaluate our tax positions for all jurisdictions and all years where the statute of limitations has not expired. FIN No. 48 requires companies to meet a "more-likely-than-not" threshold (i.e. greater than a 50 percent likelihood of being sustained under examination) prior to recording a benefit for its tax positions. Additionally, for tax positions meeting this "more-likely-than-not" threshold, the amount of benefit is limited to the largest benefit that has a greater than 50 percent probability of being realized upon ultimate settlement. The cumulative effect of applying the provisions of the new interpretation will be recorded as an adjustment to the beginning balance of retained earnings, or other components of stockholders' equity, as appropriate, in the period of adoption. We will adopt the provisions of this interpretation effective January 1, 2007, and are currently evaluating the impact, if any, that this interpretation will have on our financial statements.

## 2. Acquisitions

In August 2005, we acquired Medicine Bow Energy Corporation, a privately held energy company, for total cash consideration of $853 million. Medicine Bow owns a 43.1 percent interest in Four Star Oil & Gas Company, an unconsolidated affiliate. Our proportionate share of the operating results associated with Four Star are reflected as earnings from unconsolidated affiliates in our financial statements.

We reflected Medicine Bow's results of operations in our income statement beginning September 1, 2005. The following summary of unaudited pro forma consolidated results of operations for the quarter and six months ended June 30, 2005 reflect the combination of our historical income statements with Medicine Bow, adjusted for certain effects of the acquisition and related funding. These pro forma results are prepared as if the acquisition had occurred as of the beginning of the periods presented and are not necessarily indicative of the operating results that would have occurred had the acquisition been consummated at that date, nor are they necessarily indicative of future operating results.

| | Quarter Ended June 30, 2005 | Six Months Ended June 30, 2005 |
|---|---|---|
| | (In millions, except per share amounts) | |
| Revenues | $1,184 | $2,285 |
| Net loss available to common stockholders | (242) | (130) |
| Basic net loss per share | (0.38) | (0.20) |
| Diluted net loss per share | (0.38) | (0.17) |

## 3. Divestitures

*Sales of Assets and Investments*

During the six months ended June 30, we completed the sale of a number of assets and investments. The following table summarizes the proceeds from these sales:

| | 2006 | 2005 |
|---|---|---|
| | (In millions) | |
| Continuing operations | | |
| Pipelines | $ — | $ 35 |
| Exploration and Production | 81 | — |
| Power | 413 | 176 |
| Field Services | — | 501 |
| Corporate | 2 | 121 |
| Total continuing operations[1] | 496 | 833 |
| Discontinued operations | 358 | 85 |
| Total proceeds | $854 | $918 |

(1) Proceeds exclude returns of invested capital and cash transferred with the assets sold and include costs incurred in preparing assets for disposal. These items decreased our sales proceeds by $21 million for the six months ended June 30, 2006 and increased our sales proceeds by $1 million for the six months ended June 30, 2005.

The following table summarizes the significant assets sold during the six months ended June 30:

| | 2006 | 2005 |
|---|---|---|
| Pipelines | | • Facilities located in the southeastern U.S. |
| Exploration and Production | • Natural gas and oil properties primarily in south Texas | |
| Power | • Interests in power plants in Brazil, Asia, Central America, Hungary and Peru<br>• Cost basis investments<br>• Power turbine | • Cedar Brakes I and II<br>• Interests in power plants in India, England and the U.S.<br>• Power turbine |
| Field Services | | • 9.9% interest in general partner of Enterprise Products Partners, L.P.<br>• 13.5 million common units in Enterprise<br>• Interest in Indian Springs natural gas gathering system and processing facility |
| Corporate | | • Lakeside Technology Center |
| Discontinued | • Macae power facility in Brazil | • Interest in Paraxylene facility<br>• Methyl tertiary-butyl ether (MTBE) processing facility<br>• International natural gas and oil production properties |

In addition to the above, subsequent to June 30, 2006, we completed the sale of our interests in certain power assets, including our investment in Midland Cogeneration Venture (MCV) and several Asian assets, for approximately $30 million. We also have agreements to sell additional assets for total proceeds of approximately $130 million, including certain Brazilian natural gas and oil properties and substantially all of our interests in our remaining domestic, Asian and Central American power assets.

*Discontinued Operations*

Under SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, we classify assets to be disposed of as held for sale or, if appropriate, discontinued operations when they have received appropriate approvals by our management or Board of Directors and when they meet other criteria. Cash flows from our discontinued businesses are reflected as discontinued operating, investing, and financing activities in our statement of cash flows. To the extent these operations do not maintain separate cash balances, we reflect the net cash flows generated from these businesses as a contribution to continuing operations. We reflect this contribution in cash from continuing financing activities. The following is a description of our discontinued operations and summarized results of these operations for the quarters and six months ended June 30, 2006 and 2005.

*Macae and Other International Power Operations.* In the first quarter of 2006, our Board of Directors approved the sale of our interest in the Macae power facility in Brazil to Petrobras. In conjunction with the sale completed in April 2006, we received $358 million and repaid approximately $229 million of Macae's project debt. During 2005, our Board of Directors approved the sale of our Asian and Central American power asset portfolio, which included our consolidated interests in the Nejapa, CEBU and East Asia Utilities power plants. We completed the sale of our CEBU and East Asia Utilities power plants in July 2006. Our only remaining power asset in discontinued operations is our Nejapa power plant. We expect to complete the sale of this plant in the second half of 2006. For a further discussion related to our international power operations, see Note 14.

*South Louisiana Gathering and Processing Operations.* During the second quarter of 2005, our Board of Directors approved the sale of our south Louisiana gathering and processing assets, which were part of our historical Field Services segment. In the fourth quarter of 2005, we completed the sale of these assets.

*International Natural Gas and Oil Production Operations.* In 2004 and 2005, we sold these operations, which consisted of our Canadian and certain other international natural gas and oil production operations.

*Petroleum Markets.* As of December 31, 2005, substantially all of these operations had been sold.

| | Macae and Other International Power Operations | South Louisiana Gathering and Processing Operations | International Natural Gas and Oil Production Operations | Petroleum Markets | Total |
|---|---|---|---|---|---|
| | (In millions) | | | | |
| **Quarter Ended June 30, 2006** | | | | | |
| Revenues | $ 53 | $ — | $ — | $ — | $ 53 |
| Costs and expenses | (58) | — | — | — | (58) |
| Gain on long-lived assets | 7 | 5 | — | — | 12 |
| Other income | 2 | — | — | — | 2 |
| Interest and debt expense | (6) | — | — | — | (6) |
| Income (loss) before income taxes | $ (2) | $ 5 | $ — | $ — | 3 |
| Income taxes | | | | | 6 |
| Loss from discontinued operations, net of income taxes | | | | | $ (3) |
| **Quarter Ended June 30, 2005** | | | | | |
| Revenues | $ 55 | $ 90 | $ — | $ 30 | $ 175 |
| Costs and expenses | (78) | (79) | (1) | (33) | (191) |
| Loss on long-lived assets | (360) | — | (4) | — | (364) |
| Other income (expense) | 4 | — | — | (4) | — |
| Interest and debt expense | (7) | — | — | — | (7) |
| Income (loss) before income taxes | $(386) | $ 11 | $ (5) | $ (7) | (387) |
| Income taxes | | | | | (82) |
| Loss from discontinued operations, net of income taxes | | | | | $(305) |
| **Six Months Ended June 30, 2006** | | | | | |
| Revenues | $ 103 | $ — | $ — | $ — | $ 103 |
| Costs and expenses | (111) | — | — | — | (111) |
| Gain (loss) on long-lived assets | (5) | 5 | — | — | — |
| Other income | 2 | — | — | — | 2 |
| Interest and debt expense | (13) | — | — | — | (13) |
| Income (loss) before income taxes | $ (24) | $ 5 | $ — | $ — | (19) |
| Income taxes | | | | | 3 |
| Loss from discontinued operations, net of income taxes | | | | | $ (22) |

| | Macae and Other International Power Operations | South Louisiana Gathering and Processing Operations | International Natural Gas and Oil Production Operations | Petroleum Markets | Total |
|---|---|---|---|---|---|
| | | | (In millions) | | |
| **Six Months Ended June 30, 2005** | | | | | |
| Revenues | $ 109 | $ 177 | $ 2 | $ 74 | $ 362 |
| Costs and expenses | (131) | (157) | (2) | (86) | (376) |
| Gain (loss) on long-lived assets | (374) | — | (5) | 3 | (376) |
| Other income | 6 | — | — | 11 | 17 |
| Interest and debt expense | (14) | — | — | — | (14) |
| Income (loss) before income taxes | $(404) | $ 20 | $ (5) | $ 2 | (387) |
| Income taxes | | | | | (75) |
| Loss from discontinued operations, net of income taxes | | | | | $(312) |

Assets and liabilities of discontinued operations primarily relate to our international power facilities. As of June 30, 2006 and December 31, 2005, we had total assets of approximately $38 million and $583 million classified as discontinued operations. As of June 30, 2006 and December 31, 2005, total liabilities classified as discontinued operations were approximately $24 million and $422 million.

## 4. Loss on Long-Lived Assets

Our loss on long-lived assets consists of realized gains and losses on sales and impairments of long-lived assets. During the six months ended June 30, 2005, our net loss on long-lived assets of $7 million was primarily due to a $15 million impairment recorded by our Power segment on several of its power turbines, partially offset by a gain of $9 million in our Pipelines segment on the sale of facilities located in the southeastern United States.

## 5. Income Taxes

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

| | Quarters Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2006 | 2005 | 2006 | 2005 |
| | (In millions, except rates) | | | |
| Income taxes | $ 2 | $35 | $167 | $36 |
| Effective tax rate | 1% | 34% | 24% | 17% |

We compute our quarterly income taxes using a method based on applying an anticipated annual effective rate to our year-to-date income or loss except for significant unusual or infrequently occurring transactions. Income taxes for significant or infrequently occurring transactions are separately computed and recorded in the period that the specific transaction occurs. The IRS audits of the Coastal Corporation's 1998-2000 tax years and El Paso's 2001 tax year were concluded in 2006. During 2006, our overall effective tax rate on continuing operations was lower than the statutory rate of 35 percent primarily due to conclusion of these IRS audits resulting in the reduction of tax contingencies and reinstatement of certain tax credits. These amounts were $34 million and $50 million for the quarter and six months ended June 30, 2006. Also reducing our effective rate in 2006 were net tax benefits recognized on certain foreign investments, among other items.

During the six months ended June 30, 2005, our overall effective tax rate on continuing operations was different than the statutory rate of 35 percent primarily due to a reduction in our liabilities for tax contingencies as a result of an IRS settlement for the 1995-1997 income tax returns for The Coastal Corporation.

*Other Tax Matters.* The IRS audit of El Paso's 2002 tax year is still subject to review but is expected to be concluded in 2006. In addition, the IRS is currently auditing El Paso's 2003 and 2004 tax years. We have recorded a liability for tax contingencies associated with these audits, as well as for proceedings and examinations with other taxing authorities, which management believes is adequate. As these matters are finalized, we may be required to adjust our liability which could significantly increase or decrease our income tax expense in future periods.

## 6. Earnings Per Share

We calculated basic and diluted earnings per common share as follows:

| | 2006 | | 2005 | |
|---|---|---|---|---|
| | Basic | Diluted | Basic | Diluted |
| | (in millions, except per share amounts) | | | |
| **Quarter Ended June 30,** | | | | |
| Income from continuing operations | $ 153 | $ 153 | $ 67 | $ 67 |
| Convertible preferred stock dividends | (9) | — | (8) | (8) |
| Income from continuing operations available to common stockholders | 144 | 153 | 59 | 59 |
| Discontinued operations | (3) | (3) | (305) | (305) |
| Net income (loss) available to common stockholders | $ 141 | $ 150 | $ (246) | $ (246) |
| Weighted average common shares outstanding | 671 | 671 | 641 | 641 |
| Effect of dilutive securities: | | | | |
| Options and restricted stock | — | 4 | — | 2 |
| Convertible preferred stock | — | 57 | — | — |
| Weighted average common shares outstanding and dilutive potential common shares | 671 | 732 | 641 | 643 |
| Earnings per common share: | | | | |
| Income from continuing operations | $ 0.22 | $ 0.21 | $ 0.09 | $ 0.09 |
| Discontinued operations, net of income taxes | (0.01) | — | (0.47) | (0.47) |
| Net income (loss) | $ 0.21 | $ 0.21 | $(0.38) | $(0.38) |

| | 2006 | | 2005 | |
|---|---|---|---|---|
| | **Basic** | **Diluted** | **Basic** | **Diluted** |
| **Six Months Ended June 30,** | | | | |
| Income from continuing operations | $ 528 | $ 528 | $ 180 | $ 180 |
| Convertible preferred stock dividends | (19) | — | (8) | — |
| Interest on trust preferred securities | — | 5 | — | — |
| Income from continuing operations available to common stockholders | 509 | 533 | 172 | 180 |
| Discontinued operations | (22) | (22) | (312) | (312) |
| Net income (loss) available to common stockholders | $ 487 | $ 511 | $ (140) | $ (132) |
| Weighted average common shares outstanding | 664 | 664 | 640 | 640 |
| Effect of dilutive securities: | | | | |
| Options and restricted stock | — | 3 | — | 2 |
| Convertible preferred stock | — | 57 | — | 57 |
| Trust preferred securities | — | 8 | — | — |
| Weighted average common shares outstanding and dilutive potential common shares | 664 | 732 | 640 | 699 |
| Earnings per common share: | | | | |
| Income from continuing operations | $ 0.77 | $ 0.73 | $ 0.27 | $ 0.26 |
| Discontinued operations, net of income taxes | (0.03) | (0.03) | (0.49) | (0.45) |
| Net income (loss) | $ 0.74 | $ 0.70 | $(0.22) | $(0.19) |

We exclude potentially dilutive securities from the determination of diluted earnings per share (as well as their related income statement impacts) when their impact on income from continuing operations per common share is antidilutive. These antidilutive securities included our zero coupon convertible debentures (which were paid off in April 2006) and certain employee stock options in all periods presented. In addition, our trust preferred securities were antidilutive in all periods except for the six months ended June 30, 2006, and our convertible preferred stock was antidilutive for the quarter ended June 30, 2005. For a discussion of our capital stock activity in 2006, our stock based compensation arrangements, and other instruments noted above, see Notes 11 and 12 as well as our Current Report on Form 8-K dated May 12, 2006.

### 7. 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, 2006 and December 31, 2005. In the table, derivatives designated as hedges consist of instruments used to hedge our natural gas and oil production. Other commodity-based derivative contracts relate to derivative contracts that are not designated as hedges. Finally, interest rate and foreign currency hedging derivatives consist of swaps that are designed to hedge our interest rate and currency risks on long-term debt.

| | June 30, 2006 | December 31, 2005 |
|---|---|---|
| | (In millions) | |
| Net assets (liabilities) | | |
| Derivatives designated as hedges | $(157) | $ (653) |
| Other commodity-based derivative contracts | (533) | (763) |
| Total commodity-based derivatives[1] | (690) | (1,416) |
| Interest rate and foreign currency derivatives | 6 | 2 |
| Net liabilities from price risk management activities[2] | $(684) | $(1,414) |

(1) The decrease in the net liability during the six months ended June 30, 2006 is primarily due to changes in natural gas prices.
(2) Included in both current and non-current assets and liabilities on the balance sheet.

## 8. Debt, Other Financing Obligations and Other Credit Facilities

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

| | June 30, 2006 | December 31, 2005 |
|---|---|---|
| | (In millions) | |
| Short-term financing obligations, including current maturities[1] | $ 838 | $ 986 |
| Long-term financing obligations | 15,374 | 17,023 |
| Total | $16,212 | $18,009 |

(1) Excludes Macae project debt of $225 million in 2005, which was reported in liabilities related to discontinued operations.

As of June 30, 2006, we have approximately $600 million of debt that is redeemable by holders in the first half of 2007, which is prior to its stated maturity date. As a result, we have classified these amounts as current liabilities in our balance sheet. Additionally, a number of debt obligations are callable by us prior to their stated maturity date. At this time, approximately $10 billion of debt obligations are callable by us in 2006 and an additional $600 million is callable by us in 2007 and thereafter. To the extent we decide to redeem any of this debt, certain obligations will require us to pay a make whole premium.

*Long-Term Financing Obligations*

From January 1, 2006 through July 31, 2006, we had the following changes in our long-term financing obligations:

| Company | Type | Interest Rate | Book Value Increase (Decrease) | Cash Paid |
|---|---|---|---|---|
| | | | (In millions) | |
| *Repayments, repurchases, retirements and others* | | | | |
| Coastal Finance I | Trust originated preferred securities | 8.375% | (300) | (300) |
| El Paso | Zero coupon debentures | — | (615) | (615) |
| El Paso | Euro notes | 5.75% | (26) | (26) |
| El Paso | Term Loan | LIBOR + 2.75% | (260) | (260) |
| El Paso Exploration & Production Company | Revolving credit facility due 2010 | LIBOR + 1.875% | (500) | (500) |
| El Paso | Notes due 2006 | 6.50% | (110) | (110) |
| Macae[1] | Non-recourse notes due 2007 and 2008 | Variable | (229) | (229) |
| Other | Long-term debt | Various | 14 | (9) |
| | *Decreases through June 30, 2006* | | (2,026) | (2,049) |
| El Paso | Term Loan | LIBOR + 2.75% | (965) | (965) |
| | *Decreases through July 31, 2006* | | $(2,991) | $(3,014) |

(1) Included in liabilities related to discontinued operations on our balance sheet at December 31, 2005.

Prior to their redemption in 2006, we recorded accretion expense on our zero coupon bonds, which increased the principal balance of long-term debt each period. During the six months ended June 30, 2006 and 2005, the accretion recorded in interest expense was $4 million and $13 million. During the six months ended June 30, 2006 and 2005, we redeemed $615 million and $236 million of our zero coupon debentures, of which $110 million and $34 million represented increased principal due to the accretion of interest on the debentures. We account for these redemptions as financing activities in our statement of cash flows.

*Credit Facilities and Letters of Credit*

*Available Capacity under Credit Agreements.* As of June 30, 2006, we had available capacity under our credit agreements of $772 million. Of this amount $500 million related to a revolving credit agreement of our subsidiary, El Paso Exploration & Production Company (EPEP) which can be used for loans or letters of credit of EPEP through its maturity date of August 2010. Borrowings carry an interest rate of LIBOR plus a fixed percentage ranging from 1.25% to 1.875%, depending on utilization. In August 2006, we borrowed $75 million under this agreement. The remaining $272 million of capacity was available under our $3 billion credit agreement. In May 2006, our $400 million credit facility matured unutilized.

*Letters of Credit.* As of June 30, 2006, we had total outstanding letters of credit of approximately $1.6 billion, of which $1.5 billion were issued under our $3 billion credit agreement. Of the total issued letters of credit, approximately $1.0 billion collateralize our recorded obligations related to price risk management activities.

*Credit Agreement Restructuring.* In July 2006, we restructured our $3 billion credit agreement. As part of this restructuring, we entered into a new $1.75 billion credit agreement, consisting of a $1.25 billion three-year revolving credit facility and a $500 million five-year deposit letter of credit facility. At closing we had approximately $1.1 billion of letters of credit outstanding under both of these facilities. In conjunction with the restructuring, we will record a charge in the third quarter of approximately $17 million associated with unamortized financing costs on the previous credit agreement. Our subsidiaries Colorado Interstate Gas Company (CIG), El Paso Natural Gas Company (EPNG) and Tennessee Gas Pipeline Company (TGP) are eligible borrowers under this agreement. Additionally, El Paso and certain of its subsidiaries have guaranteed the $1.75 billion credit agreement, which is collateralized by our stock ownership in CIG, EPNG, and TGP.

Under the $1.25 billion revolving credit facility which matures in July 2009, we can borrow funds at LIBOR plus 1.75% or issue letters of credit at 1.75% plus a fee of 0.15% of the amount issued. We pay an annual commitment fee of 0.375% on any unused capacity under the revolving credit facility. The terms of the $500 million deposit letter of credit facility provide for the ability to issue letters of credit or borrow amounts as revolving loans with a maturity in July 2011. We pay LIBOR plus 2.00% on any amounts borrowed under this facility, 2.15% on letters of credit and 2.10% on unused capacity.

Under the new $1.75 billion credit agreement, the primary changes to our restrictive covenants as compared to our former $3 billion credit agreement were as follows:

(a) Our ratio of Debt to Consolidated EBITDA, each as defined in the credit agreement, shall not exceed 5.75 to 1 at anytime prior to June 30, 2007. Thereafter it shall not exceed 5.5 to 1 until June 29, 2008 and 5.25 to 1 from June 30, 2008 until maturity;

(b) Our ratio of Consolidated EBITDA, as defined in the credit agreement, to interest expense plus dividends paid shall not be less than 1.75 to 1 at anytime prior to December 31, 2006. Thereafter it shall not be less than 1.80 to 1 until June 29, 2008, and 2.00 to 1 from June 30, 2008 until maturity.

In addition to these covenants, we are restricted from placing liens on the equity of ANR Pipeline Company (ANR), however, we no longer have a restriction on the early retirement of debt with maturities beyond the maturity date of the $1.25 billion revolving credit facility.

*Unsecured revolving credit facility.* In July 2006, we also entered into a $500 million unsecured revolving credit facility that matures in July 2011 with a third party and a third party trust that provides for both borrowings and issuing letters of credit. We are required to pay fixed facility fees at a rate of 2.3% on the total committed amount of the facility. In addition, we will pay interest on any borrowings at a rate comprised of either a base rate or LIBOR.

## 9. Commitments and Contingencies

*Legal Proceedings*

*Shareholder/ Derivative/ ERISA Litigation*

*Shareholder Litigation.* Twenty-eight purported shareholder class action lawsuits have been pending since 2002 and are consolidated in federal court in Houston, Texas. The consolidated lawsuit alleges violations of federal securities laws against us and several of our current and former officers and directors. In July 2006, the parties executed a Memorandum of Understanding (MOU) agreeing to settle these class action lawsuits, subject to the execution of definitive settlement documents and final court approval. Under the terms of the MOU, El Paso and its insurers will pay a total of $273 million to the plaintiffs. El Paso will contribute approximately $48 million and its insurers will contribute approximately $225 million. An additional $12 million will be separately contributed by a third party under the terms of the MOU.

*Derivative Litigation.* Three shareholder derivative actions were filed, including two in federal court in Houston and one in state court in Houston. The federal court cases generally allege the same claims pled in the consolidated shareholder litigation. We recently settled the state court lawsuit, which involved the payment of approximately $17 million which was fully funded by our insurers, of which approximately $12 million will be used to fund the settlement of the shareholder litigation. At a June 2006 hearing, the judge granted final approval to the settlement reached by the parties. As a result of the settlement of the state court derivative lawsuit, one of the federal lawsuits has been dismissed and we expect to file a motion to dismiss the remaining derivative lawsuit.

*ERISA Class Action Suits.* In December 2002, a purported class action lawsuit entitled *William H. Lewis, III v. El Paso Corporation, et al.* was filed in the U.S. District Court for the Southern District of Texas alleging generally that our communication with participants in our 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. Formal discovery in this lawsuit is currently stayed. In June 2006, the parties participated in a mediated settlement negotiation.

There are insurance coverages applicable to each of these shareholder, derivative and ERISA lawsuits, subject to certain deductibles and co-pay obligations. We have established certain accruals for these matters, which we believe are adequate.

*Cash Balance Plan Lawsuit.* In December 2004, a purported class action lawsuit entitled *Tomlinson, et al. v. El Paso Corporation and El Paso Corporation Pension Plan* was filed in U.S. District Court for Denver, Colorado. The lawsuit alleges various violations of ERISA and the Age Discrimination in Employment Act as a result of our change from a final average earnings formula pension plan to a cash balance pension plan. Our costs and legal exposure related to this lawsuit are not currently determinable.

*Retiree Medical Benefits Matters.* We currently serve as the plan administrator for a medical benefits plan that covers a closed group of retirees of the Case Corporation who retired on or before June 30, 1994. Case was formerly a subsidiary of Tenneco, Inc. that was spun off prior to our acquisition of Tenneco in 1996. In connection with the Tenneco-Case Reorganization Agreement of 1994, Tenneco assumed the obligation to provide certain medical and prescription drug benefits to eligible retirees and their spouses. We assumed this obligation as a result of our merger with Tenneco. However, we believed that our liability for these benefits is limited to certain previously established maximums, or caps, and costs in excess of these maximums are assumed by plan participants. In 2002, we and Case were sued by individual retirees in federal court in Detroit, Michigan in an action entitled *Yolton et al. v. El Paso Tennessee Pipeline Co. and Case Corporation.* The suit alleges, among other things, that El Paso and Case violated ERISA and that they should be required to pay all amounts above the cap. 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 separate rulings in 2004, the court ruled that, pending a trial on the merits, Case must pay the amounts incurred above the cap and that El Paso must reimburse Case for those payments. In January 2006, these rulings were upheld on appeal by the U.S. Court of Appeals for the 6th Circuit. We intend to pursue relief with the United States Supreme Court, and if it is not granted we will proceed with a trial on the merits with regard to the issues of whether the cap is enforceable and what degree of benefits have actually vested. Until this is resolved, El Paso will indemnify Case for any payments Case makes above the cap, which are currently about $1.7 million per month. We continue to defend the action and have filed for approval by the trial court various amendments to the medical benefit plans which would allow us to deliver the benefits to plan participants in a more cost effective manner. We will seek expeditious approval of such plan amendments. Although it is uncertain what plan amendments will ultimately be approved, the approval of plan amendments could reduce our overall costs and, as a result, could reduce our recorded obligation. We have established an accrual for this matter which we believe is adequate.

*Natural Gas Commodities Litigation.* Beginning in August 2003, several lawsuits have been filed against El Paso Marketing L.P. (EPM) that allege El Paso, EPM and other energy companies conspired to manipulate the price of natural gas by providing false price information to industry trade publications that published gas indices. The first cases have been consolidated in federal court in New York for all pre-trial purposes and are styled *In re: Gas Commodity Litigation.* In September 2005, the court certified the class to include all persons who purchased or sold NYMEX natural gas futures between January 1, 2000 and December 31, 2002. Other defendants in the case have negotiated tentative settlements with the plaintiffs that have been approved by the court. EPM and the remaining defendants have petitioned the U.S. Court of Appeals for the Second Circuit for permission to appeal the class certification order. The second set of cases involve similar allegations on behalf of commercial and residential customers. These cases have been transferred to a multi-district litigation proceeding (MDL) in the U.S. District Court for Nevada , *In re Western States Wholesale Natural Gas Antitrust Litigation*. These cases have been dismissed and have been appealed. The third set of cases also involve similar allegations on behalf of certain purchasers of natural gas. These include a purported class action lawsuit styled *Leggett et al. v. Duke Energy Corporation et al.* (filed in Chancery Court of Tennessee in January 2005); the purported class action *Ever-Bloom Inc. v. AEP Energy Services Inc. et al.* (filed in federal court for the Eastern District of California in June 2005); *Farmland Industries, Inc. v. Oneok Inc.*(filed in state court in Wyandotte County, Kansas in July 2005); the purported class action *Learjet, Inc. v. Oneok Inc.* (filed in state court in Wyandotte County, Kansas in September 2005); and the purported class action *Breckenridge, et al v. Oneok Inc., et al.* (filed in state court in Denver County, Colorado in May 2006). The *Leggett* case was removed but then remanded to state court. The *Breckenridge* case has been removed and conditionally transferred to the MDL proceeding in federal district court in Nevada. The remaining three cases have all been transferred to the MDL proceeding. Similar motions to dismiss have either been filed or are anticipated to be filed in these cases as well. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

*Gas Measurement Cases.* A number of our subsidiaries were named defendants in actions that generally allege a mismeasurement of natural gas volumes and/or heating content resulting in the underpayment of royalties. The first set of cases was filed in 1997 by an individual under the False Claims Act, which has been consolidated for pretrial purposes (*In re: Natural Gas Royalties Qui Tam Litigation,* U.S. District Court for the District of Wyoming.) 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. In May 2005, a representative appointed by the court issued a recommendation to dismiss most of the actions. If the court adopts these recommendations, it will result in the dismissal of six of the district court actions involving most of the El Paso entities named as defendants. The seventh case involves only a few midstream entities previously owned by El Paso, which we believe have meritorious defenses to the underlying claims. Similar allegations were filed in a second action in 1999 in *Will Price, et al. v. Gas Pipelines and Their Predecessors, et al.,* in the District Court of Stevens County, Kansas on non-federal and non-Native American lands. The plaintiffs currently seek certification of a class of royalty owners in wells in Kansas, Wyoming and Colorado. Motions for class certification have been briefed and argued in the proceedings and the parties are awaiting the court's ruling. In each of these cases, the applicable plaintiff seeks an unspecified amount of monetary damages in the form of additional royalty payments (along with interest, expenses and punitive damages) and injunctive relief with regard to future gas measurement practices. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

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

*Bank of America.* We were a named defendant, along with Burlington Resources, Inc. (Burlington), in two class action lawsuits styled *Bank of America, et al. v. El Paso Natural Gas Company, et al.,* and *Deane W. Moore, et al. v. Burlington Northern, Inc., et al.,* each filed in 1997 in the District Court of Washita County, Oklahoma and subsequently consolidated by the court. The consolidated class action has been settled pursuant to a settlement agreement executed in January 2006 and approved by the court after a fairness hearing held in May 2006. Our settlement contribution was approximately $30 million plus interest, which had been fully accrued and was paid on August 1, 2006. A third action, styled *Bank of America, et al. v. El Paso Natural Gas and Burlington Resources Oil and Gas Company, L.P.,* was filed in October 2003 in the District Court of Kiowa County, Oklahoma asserting similar claims as to specified shallow wells in Oklahoma, Texas and New Mexico. All the claims in this action have been settled as part of the January 2006 settlement. The settlement of these claims is subject to court approval, after a fairness hearing scheduled for October 2006. We filed an action styled *El Paso Natural Gas Company v. Burlington Resources, Inc. and Burlington Resources Oil and Gas Company, L.P.* against Burlington in state court in Harris County, Texas relating to indemnity issues between Burlington and us. That action was stayed by agreement of the parties and settled in November 2005, subject to all the underlying class settlements being finalized and approved by the court.

*MTBE.* In compliance with the 1990 amendments to the Clean Air Act, certain of our subsidiaries used the gasoline additive, methyl tertiary-butyl ether (MTBE) in some of their gasoline. Certain subsidiaries 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. Some of our subsidiaries are among the defendants in 70 such lawsuits. These suits either have been or are in the process of being consolidated for pre-trial purposes in multi-district litigation in the U.S. District Court for the Southern District of New York. The plaintiffs, certain state attorneys general, various water districts and a limited number of individual water customers seek remediation of their groundwater, prevention of future contamination, damages, punitive damages, attorney's fees, court costs and, in one lawsuit, a request for medical monitoring. Among other allegations, plaintiffs assert that gasoline containing MTBE is a defective product and that defendant refiners are liable in proportion to their market share. The plaintiff states of California and New Hampshire have filed an appeal to the 2nd Circuit Court of Appeals challenging the removal of the cases from state to federal court. That appeal is pending. Our costs and legal exposure related to these lawsuits.

*Government Investigations and Inquiries*

*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 will continue to cooperate with the SEC in its investigation related to such reserve revisions.

*Iraq Oil Sales.* Several government agencies and congressional committees have been reviewing and making formal and informal requests related to The Coastal Corporation's and El Paso's purchases of crude oil from Iraq under the United Nations' Oil for Food Program. These agencies include a grand jury of the U.S. District Court for the Southern District of New York, the SEC and several congressional committees. In October 2005, a grand jury sitting in the Southern District of New York handed down an indictment against Oscar S. Wyatt, Jr., a former CEO and Chairman of Coastal. Also in October 2005, the Independent Inquiry Committee into the United Nations' Oil for Food Program issued its final report. The report states that $201,877 in surcharges were paid with respect to a single contract entered into by our subsidiary, Coastal Petroleum NV (CPNV). The report lists Oscar Wyatt as the non-contractual beneficiary of the contract. The report indicates that the payments were made by two other individuals or entities and does not contend that CPNV paid that surcharge. We continue to cooperate with all government investigations into this matter.

*Other Government Investigations.* We also continue to provide information and cooperate with the inquiry or investigation of the U.S. Attorney and the SEC in response to requests for information regarding price reporting of transactional data to the energy trade press and the hedges of our natural gas production.

*Other Contingencies*

*EPNG Rate Case.* In June 2005, EPNG filed a rate case with the FERC proposing an increase in revenues of 10.6 percent or $56 million annually over current tariff rates, new services and revisions to certain terms and conditions of existing services. On January 1, 2006, the rates became effective and are subject to refund. In March 2006, the FERC issued an order that generally approved our proposed new services, which were implemented on June 1, 2006. In April 2006, we solicited and received bids for certain new services and have entered into several contracts for new services. EPNG is continuing settlement discussions with its customers, and is evaluating the merits of filing an additional rate case later this year for rates to be effective next year. The outcome of this or any additional rate case cannot be predicted with certainty at this time.

*CIG Rate Case.* In May 2006, CIG filed a request with the FERC to change the effective date of new rates from January 1, 2007 to February 1, 2007 to allow for continued settlement discussions with its customers. This request was granted by the FERC. In June 2006, CIG filed a petition with the FERC to amend its filing requirement and to approve a settlement reached with its customers to be effective October 1, 2006. CIG's petition to amend the filing requirement and to approve the settlement was unopposed by the parties and FERC staff. The outcome of this rate case and its impact on revenues cannot be predicted with certainty at this time.

*Iraq Imports.* In December 2005, the Ministry of Oil for the State Oil Marketing Organization of Iraq (SOMO) sent an invoice to one of our subsidiaries with regard to shipments of crude oil that SOMO alleged were purchased and paid for by Coastal in 1990. The invoices request an additional $144 million of payments for such shipments, along with an allegation of an undefined amount of interest. The invoice appears to be associated with cargoes that Coastal had purchased just before the 1990 invasion of Kuwait by Iraq. We have requested additional information from SOMO to further assist in our evaluation of the invoice and the underlying facts. In addition, we are evaluating our legal defenses, including applicable statute of limitation periods.

*Navajo Nation.* Approximately 900 looped pipeline miles of the north mainline of our EPNG pipeline system are located on lands held in trust by the United States for the benefit of the Navajo Nation. Our rights-of-way on lands crossing the Navajo Nation expired in October 2005, and we entered into an interim agreement with the Navajo Nation to extend the use of our existing rights-of-way through the end of 2006. Negotiations on the terms of the long-term agreement are continuing. Although the Navajo Nation has at times demanded more than ten times the $2 million annual fee that existed prior to the execution of the interim agreement, EPNG continues to offer a combination of cash and non-cash consideration, including collaborative projects to benefit the Navajo Nation. In addition, EPNG continues to preserve other legal and regulatory alternatives, which include continuing to pursue our application with the Department of the Interior for renewal of our rights-of-way on Navajo Nation lands. EPNG also continues to press for public policy intervention by Congress in this area. The Energy Policy Act of 2005 commissioned a comprehensive study of energy infrastructure rights-of-way on tribal lands. The study, to be conducted jointly by the Department of Energy and the Department of Interior, is scheduled to be submitted to Congress by August 2006. It is uncertain whether our negotiation, public policy or litigation efforts will be successful, or if successful, what the ultimate cost will be of obtaining the rights-of-way or whether EPNG will be able to recover these costs in its rates.

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. For each of our outstanding legal and other contingent matters, we evaluate the merits of the case, our exposure to the matter, possible legal or settlement strategies and the likelihood of an unfavorable outcome. If we determine that an unfavorable outcome is probable and can be estimated, we establish the necessary accruals. While the outcome of these matters, discussed above, cannot be predicted with certainty, and there are still uncertainties related to the costs we may incur, based upon our evaluation and experience to date, we believe we have established appropriate reserves for these matters. However, it is possible that new information or future developments could require us to reassess our potential exposure related to these matters and adjust our accruals accordingly, and these adjustments could be material. As of June 30, 2006, we had approximately $570 million accrued, net of related insurance receivables and restricted cash, for outstanding legal and other contingent matters.

### *Environmental Matters*

We are subject to federal, state and local laws and regulations governing environmental quality and pollution control. These laws and regulations require us to remove or remedy the effect on the environment of the disposal or release of specified substances at current and former operating sites. As of June 30, 2006, we have accrued approximately $381 million, which has not been reduced by $31 million for amounts to be paid directly under government sponsored programs. Our accrual includes approximately $370 million for expected remediation costs and associated onsite, offsite and groundwater technical studies and approximately $11 million for related environmental legal costs. Of the $381 million accrual, $76 million was reserved for facilities we currently operate and $305 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 $381 million to approximately $592 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 ($70 million). Second, where the most likely outcome cannot be estimated, a range of costs is established ($311 million to $522 million) and if no one amount in that range is more likely than any other, the lower end of the expected range has been accrued. Our environmental remediation projects are in various stages of completion. Our recorded liabilities reflect our current estimates of amounts we will expend to remediate these sites. However, depending on the stage of completion or assessment, the ultimate extent of contamination or remediation required may not be known. As additional assessments occur or remediation efforts continue, we may incur additional liabilities. By type of site, our reserves are based on the following estimates of reasonably possible outcomes:

| Sites | June 30, 2006 Expected | High |
|---|---|---|
| | (In millions) | |
| Operating | $ 76 | $ 82 |
| Non-operating | 269 | 452 |
| Superfund | 36 | 58 |
| Total | $381 | $592 |

Below is a reconciliation of our accrued liability from January 1, 2006 to June 30, 2006 (in millions):

| | |
|---|---|
| Balance as of January 1, 2006 | $379 |
| Additions/adjustments for remediation activities | 34 |
| Payments for remediation activities | (32) |
| Balance as of June 30, 2006 | $381 |

For the remainder of 2006, we estimate that our total remediation expenditures will be approximately $58 million, most of which will be expended under government directed clean-up plans. In addition, we expect to make capital expenditures for environmental matters of approximately $93 million in the aggregate for the years 2006 through 2010. These expenditures primarily relate to compliance with clean air regulations.

*Polychlorinated Biphenyls (PCB) Cost Recoveries.* Pursuant to a consent order executed with the United States EPA in May 1994, TGP has been conducting various remediation activities at certain of its compressor stations associated with the presence of PCB and certain other hazardous materials. TGP has recovered a substantial portion of the environmental costs identified in its PCB remediation project through a surcharge to its customers. An agreement with TGP's customers, approved by the FERC in November 1995, established the surcharge mechanism. The surcharge collection period is currently set to expire in June 2008, with further extensions subject to a filing with the FERC. As of June 30, 2006, TGP had pre-collected PCB costs of approximately $136 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. TGP's regulatory liability for estimated future refund obligations to its customers increased from approximately $110 million at December 31, 2005 to approximately $123 million as of June 30, 2006.

*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 53 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, 2006, we have estimated our share of the remediation costs at these sites to be between $36 million and $58 million. Because the clean-up costs are estimates and are subject to revision as more information becomes available about the extent of remediation required, and in some cases we have asserted a defense to any liability, our estimates could change. Moreover, liability under the federal CERCLA statute is joint and several, meaning that we could be required to pay in excess of our pro rata share of remediation costs. Our understanding of the financial strength of other PRPs has been considered, where appropriate, in estimating our liabilities. Accruals for these issues are included in the previously indicated estimates for Superfund sites.

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

*Guarantees*

We are involved in various joint ventures and other ownership arrangements that sometimes require additional financial support that results in the issuance of financial and performance guarantees. For a description of these commitments, see our Current Report on Form 8-K dated May 12, 2006. As of June 30, 2006, we had a liability of $69 million related to our guarantees and indemnification arrangements. These arrangements had a total stated value of $324 million, for which we are indemnified by third parties for $24 million. These amounts exclude guarantees for which we have issued related letters of credit discussed in Note 8. Included in the above stated value of $324 million is approximately $120 million associated with tax matters, related interest and other indemnifications arising out of the sale of our Macae power facility.

In addition to the exposures described above, a trial court has ruled, which was upheld on appeal, that we are required to indemnify a third party for benefits being paid to a closed group of retirees of one of our former subsidiaries. We have a liability of approximately $380 million associated with our estimated exposure under this matter as of June 30, 2006. For a further discussion of this matter, see *Retiree Medical Benefits Matters* above.

## 10. Retirement Benefits

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

| | Quarters Ended June 30, | | | | Six Months Ended June 30, | | | |
|---|---|---|---|---|---|---|---|---|
| | Pension Benefits | | Other Postretirement Benefits | | Pension Benefits | | Other Postretirement Benefits | |
| | 2006 | 2005 | 2006 | 2005 | 2006 | 2005 | 2006 | 2005 |
| | (In millions) | | | | | | | |
| Service cost | $ 4 | $ 6 | $— | $— | $ 8 | $ 12 | $— | $— |
| Interest cost | 29 | 29 | 7 | 8 | 58 | 58 | 14 | 15 |
| Expected return on plan assets | (44) | (42) | (4) | (3) | (88) | (84) | (8) | (6) |
| Amortization of net actuarial loss | 14 | 16 | — | — | 28 | 32 | — | — |
| Amortization of transition obligation | — | — | — | 2 | — | — | — | 4 |
| Amortization of prior service cost[(1)] | — | (1) | — | — | — | (2) | — | — |
| Net benefit cost | $ 3 | $ 8 | $ 3 | $ 7 | $ 6 | $ 16 | $ 6 | $13 |

(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 $28 million and $36 million of cash contributions to our Supplemental Executive Retirement Plan (SERP) and other postretirement plans during the six months ended June 30, 2006 and 2005. We expect to contribute an additional $2 million to the SERP and $19 million to our other postretirement plans for the remainder of 2006. Contributions to our other retirement benefit plans will be approximately $8 million for the remainder of 2006.

### 11. Capital Stock

In May 2006, we issued 35.7 million shares of common stock for net proceeds of approximately $500 million. The table below shows the amount of dividends paid and declared (in millions, except per share amounts) on our common and preferred stock:

| | Common Stock ($0.04/share) | Convertible Preferred Stock (4.99%/year) |
|---|---|---|
| Amount paid through June 30, 2006 | $52 | $19 |
| Amount paid in July 2006 | $27 | $ 9 |
| Declared subsequent to June 30, 2006: | | |
| Date of declaration | July 20, 2006 | July 20, 2006 |
| Date payable | October 2, 2006 | October 2, 2006 |
| Payable to shareholders of record | September 1, 2006 | September 15, 2006 |

Dividends on our common and preferred stock are treated as a reduction of additional paid-in-capital since we currently have an accumulated deficit. We expect dividends paid on our common and preferred stock in 2006 will be taxable to our stockholders because we anticipate that these dividends will be paid out of current or accumulated earnings and profits for tax purposes. For a further discussion of our common and preferred stock including dividend restrictions, refer to our Current Report on Form 8-K dated May 12, 2006.

### 12. Stock-Based Compensation

Under our stock-based compensation plans, we may issue to our employees incentive stock options on our common stock (intended to qualify under Section 422 of the Internal Revenue Code), non-qualified stock options, restricted stock, restricted stock units, stock appreciation rights, performance shares, performance units and other stock-based awards. We are authorized to grant awards of approximately 42.5 million shares of our common stock under our current plans, which includes 35 million shares under our employee plan, 2.5 million shares under our non-employee director plan and 5 million shares under our employee stock purchase plan. At June 30, 2006, approximately 36 million shares remain available for grant under our current plans. In addition, we have approximately 25 million shares of stock option awards outstanding that were granted under terminated plans that obligate us to issue additional shares of common stock if they are exercised. Stock option exercises and restricted stock are funded primarily through the issuance of new common shares.

As discussed in Note 1, we adopted SFAS No. 123(R) on January 1, 2006 and began recognizing the cost of all of our stock-based compensation arrangements based on the grant date fair value of those awards in our financial statements. We record this cost as operation and maintenance expense in our consolidated statements of income over the requisite service period for each separately vesting portion of the award, net of estimates of pre-vesting forfeiture rates. If actual forfeitures differ from our estimates, additional adjustments to compensation expense will be required in future periods.

The impact of the adoption of SFAS No. 123(R) on earnings per share was less than $0.01 per basic and diluted share for the quarter ended June 30, 2006, and approximately $0.01 per basic and diluted share for the six months ended June 30, 2006. During the quarter and six months ended June 30, 2006, we recognized $3 million and $6 million of additional pre-tax compensation expense, capitalized less than $1 million of this expense as part of fixed assets and recorded $1 million and $2 million of income tax benefits as our option awards vested. We expect to record incremental compensation expense of approximately $6 million for the remainder of the year.

The following table shows the impact on the net loss available to common stockholders and loss per share had we applied the provisions of SFAS No. 123 in historical periods (in millions, except for per share amounts):

| | Quarter Ended June 30, 2005 | Six Months Ended June 30, 2005 |
|---|---|---|
| Net loss available to common stockholders, as reported | $ (246) | $ (140) |
| Add: Stock-based employee compensation expense included in reported net loss, net of taxes | 3 | 5 |
| Deduct: Total stock-based compensation expense, determined under fair-value based method for all awards, net of taxes | 5 | 9 |
| Net loss available to common stockholders, pro forma | $ (248) | $ (144) |
| Loss per share: | | |
| Basic, as reported | $(0.38) | $(0.22) |
| Basic, pro forma | $(0.39) | $(0.23) |
| Diluted, as reported | $(0.38) | $(0.19) |
| Diluted, pro forma | $(0.39) | $(0.19) |

Under SFAS No. 123(R), beginning January 1, 2006, excess tax benefits from the exercise of stock-based compensation awards are recognized in cash flows from financing activities. Prior to this date, these amounts were recorded in cash flows from operating activities. Our excess tax benefits recorded in 2006 and 2005 were not material.

*Non-Qualified Stock Options*

We grant non-qualified stock options to our employees with an exercise price equal to the market value of our stock on the grant date. Our stock option awards have contractual terms of 10 years and generally vest in equal amounts over three years from the grant date. We do not pay dividends on unexercised options. A summary of our stock option transactions for the six months ended June 30, 2006 is presented below:

| | # Shares Underlying Options | Weighted Average Exercise Price Per Share | Weighted Average Remaining Contractual Term (In years) | Aggregate Intrinsic Value (In millions) |
|---|---|---|---|---|
| Outstanding at December 31, 2005 | 28,083,485 | $37.12 | | |
| Granted | 2,235,675 | $12.21 | | |
| Exercised | (249,325) | $ 7.99 | | |
| Forfeited or canceled | (338,997) | $10.50 | | |
| Expired | (2,855,642) | $38.77 | | |
| Outstanding at June 30, 2006 | 26,875,196 | $35.48 | 5.3 | $59 |
| Vested at June 30, 2006 or expected to vest in the future | 26,504,758 | $35.83 | 5.2 | $57 |
| Exercisable at June 30, 2006 | 19,466,428 | $45.16 | 4.0 | $22 |

Total compensation cost related to non-vested option awards not yet recognized at June 30, 2006 was approximately $18 million, which is expected to be recognized over a weighted average period of 12 months. Options exercised during the six months ended June 30, 2006 had a total intrinsic value of approximately $2 million and generated $2 million of cash proceeds. The associated income tax benefit generated was not material. The total intrinsic value, cash received and income tax benefit generated from option exercises was not material during the six months ended June 30, 2005.

*Fair Value Assumptions.* The fair value of each stock option granted is estimated on the date of grant using a Black-Scholes option-pricing model based on several assumptions. These assumptions are based on management's best estimate at the time of grant. For the six months ended June 30, 2006 and 2005, the weighted average grant date fair value per share of options granted was $4.94 and $3.86. Listed below is the weighted average of each assumption based on grants in each of the quarters and six months ended June 30:

| | Quarters Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2006 | 2005 | 2006 | 2005 |
| Expected Term in Years | 6.25 | 4.83 | 6.25 | 4.83 |
| Expected Volatility | 38% | 42% | 38% | 42% |
| Expected Dividends | 1.3% | 1.5% | 1.3% | 1.5% |
| Risk-Free Interest Rate | 5.0% | 3.7% | 5.0% | 3.7% |

We currently estimate expected volatility based on an analysis of implied volatilities from traded options on our common stock and our historical stock price volatility over the expected term, adjusted for certain time periods. Prior to January 1, 2006, we estimated expected volatility based primarily on adjusted historical stock price volatility. Effective January 1, 2006, we adopted the provisions of SEC Staff Accounting Bulletin No. 107 and estimate the expected term of our option awards based on the vesting period and average remaining contractual term.

*Restricted Stock*

We may grant shares of restricted common stock, which carry voting and dividend rights, to our officers and employees. However, sale or transfer of the shares is restricted until they vest. We currently have outstanding and grant only time-based restricted stock. Historically, we have also granted performance-based restricted share awards. These shares have fully vested or were forfeited prior to the end of 2005. The fair value of our time-based restricted shares is determined on the grant date and these shares typically vest over three years from the date of grant. A summary of the changes in our non-vested restricted shares for the six months ended June 30, 2006, is presented below:

| Nonvested Shares | # Shares | Weighted-Average Grant Date Fair Value Per Share |
|---|---|---|
| Nonvested at December 31, 2005 | 3,916,030 | $10.83 |
| Granted | 1,133,701 | $12.26 |
| Vested | (1,819,455) | $12.32 |
| Forfeited | (142,914) | $10.34 |
| Nonvested at June 30, 2006 | 3,087,362 | $10.50 |

The weighted average grant date fair value per share for restricted stock granted during the first six months of 2006 and 2005 was $12.26 and $10.68. The total fair value of shares vested during the six months ended June 30, 2006 and 2005 was $22 million and $13 million.

During the quarter and six months ended June 30, 2006, we recognized approximately $6 million and $10 million of pre-tax compensation expense, capitalized less than $1 million as part of fixed assets and recorded $2 million and $4 million of income tax benefits related to restricted stock arrangements. During the quarter and six months ended June 30, 2005 we recognized approximately $4 million and $8 million of pretax compensation expense, capitalized less than $1 million of this expense as part of fixed assets and recorded $1 million and $3 million of income tax benefits related to restricted stock arrangements. The total unrecognized compensation cost related to these arrangements at June 30, 2006 was approximately $20 million, which is expected to be recognized over a weighted average period of 11 months. Upon adoption of SFAS No. 123(R), we recorded a cumulative effect of a change in accounting principle of less than $1 million as a result of estimating forfeitures for restricted stock on the date of grant as compared to recognizing forfeitures as they occur. We also reclassified unearned compensation as additional paid-in capital on our balance sheet as required by this standard.

*Employee Stock Purchase Plan*

In July 2005, we reinstated our employee stock purchase plan under Section 423 of the Internal Revenue Code. The amended and restated plan allows participating employees the right to purchase our common stock at 95 percent of the market price on the last trading day of each month. This plan is non-compensatory under the provisions of SFAS No. 123(R).

**13. Business Segment Information**

As of June 30, 2006, our business consists of our core Pipelines and Exploration and Production segments, as well as our Marketing and Trading and Power segments. Prior to 2006, we also had a Field Services segment. As of January 1, 2006, we had divested of substantially all of the assets and operations in this segment. 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. Our operating results for all periods presented reflect certain operations as discontinued operations, see Note 3.

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) 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 flows. Below is a reconciliation of our EBIT to our income from continuing operations for the periods ended June 30:

| | Quarters Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2006 | 2005 | 2006 | 2005 |
| | (In millions) | | | |
| Total EBIT | $ 487 | $ 438 | $1,375 | $ 901 |
| Interest and debt expense | (332) | (333) | (680) | (676) |
| Preferred interests of consolidated subsidiaries | — | (3) | — | (9) |
| Income taxes | (2) | (35) | (167) | (36) |
| Income from continuing operations | $ 153 | $ 67 | $ 528 | $ 180 |

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

| Quarter Ended June 30, | Segments: Pipelines | Segments: Exploration and Production | Segments: Marketing and Trading | Segments: Power | Corporate[1] | Total |
|---|---|---|---|---|---|---|
| | (In millions) | | | | | |
| 2006 | | | | | | |
| Revenues from external customers | $688 | $234[2] | $ 255 | $ 2 | $ 35 | $1,214 |
| Intersegment revenues | 17 | 228[2] | (237) | — | (8) | — |
| Operation and maintenance | 221 | 98 | 9 | 16 | 41 | 385 |
| Depreciation, depletion and amortization | 115 | 156 | 1 | 1 | 5 | 278 |
| Earnings from unconsolidated affiliates | 43 | 1 | — | 8 | — | 52 |
| EBIT | 335 | 163 | 13 | 10 | (34) | 487 |

| | Segments: Pipelines | Segments: Exploration and Production | Segments: Marketing and Trading | Segments: Power | Segments: Field Services | Corporate[1] | Total |
|---|---|---|---|---|---|---|---|
| | (In millions) | | | | | | |
| 2005 | | | | | | | |
| Revenues from external customers | $634 | $171[2] | $ 240 | $ 57 | $ 23 | $ 24 | $1,149 |
| Intersegment revenues | 19 | 281[2] | (261) | (3) | 5 | (21) | 20[3] |
| Operation and maintenance | 214 | 99 | 9 | 25 | 4 | 34 | 385 |
| Depreciation, depletion and amortization | 108 | 157 | 1 | — | 1 | 17 | 284 |
| (Gain) loss on long-lived assets | (3) | — | — | 1 | 6 | (4) | — |
| Earnings (losses) from unconsolidated affiliates | 38 | — | — | (59) | 2 | — | (19) |
| EBIT | 309 | 176 | (30) | (2) | (3) | (12) | 438 |

(1) Includes eliminations of intercompany transactions. Our intersegment revenues, along with our intersegment operating expenses, were incurred in the normal course of business between our operating segments. For the quarters ended June 30, 2006 and 2005, we recorded an intersegment revenue elimination of $8 million and $21 million and operation and maintenance expense eliminations of less than $1 million, which is included in the "Corporate" column, to remove intersegment transactions.

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

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

| Six Months Ended June 30, | Segments: Pipelines | Segments: Exploration and Production | Segments: Marketing and Trading | Segments: Power | Corporate[1] | Total |
|---|---|---|---|---|---|---|
| | (In millions) | | | | | |
| 2006 | | | | | | |
| Revenues from external customers | $1,511 | $315[2] | $ 853 | $ 3 | $ 63 | $2,745 |
| Intersegment revenues | 31 | 613[2] | (630) | — | (14) | — |
| Operation and maintenance | 438 | 186 | 12 | 30 | 53 | 719 |
| Depreciation, depletion and amortization | 230 | 302 | 2 | 1 | 15 | 550 |
| Earnings (losses) from unconsolidated affiliates | 75 | 8 | — | 15 | (1) | 97 |
| EBIT | 813 | 362 | 221 | 13 | (34) | 1,375 |

| | Segments | | | | | | |
|---|---|---|---|---|---|---|---|
| | Pipelines | Exploration and Production | Marketing and Trading | Power | Field Services | Corporate[1] | Total |
| | (In millions) | | | | | | |
| 2005 | | | | | | | |
| Revenues from external customers | $1,382 | $302[2] | $ 333 | $ 82 | $ 65 | $ 51 | $2,215 |
| Intersegment revenues | 39 | 589[2] | (529) | (5) | 11 | (63) | 42[3] |
| Operation and maintenance | 417 | 183 | 19 | 45 | 3 | 129 | 796 |
| Depreciation, depletion and amortization | 219 | 303 | 2 | 1 | 2 | 26 | 553 |
| (Gain) loss on long-lived assets | (10) | — | — | 14 | 7 | (4) | 7 |
| Earnings (losses) from unconsolidated affiliates | 76 | — | — | (87) | 182 | — | 171 |
| EBIT | 721 | 359 | (215) | (41) | 179 | (102) | 901 |

(1) Includes eliminations of intercompany transactions. Our intersegment revenues, along with our intersegment operating expenses, were incurred in the normal course of business between our operating segments. For the six months ended June 30, 2006 and 2005, we recorded an intersegment revenue elimination of $14 million and $63 million and operation and maintenance expense eliminations of $1 million, which is included in the "Corporate" column, to remove intersegment transactions.

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

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

Total assets by segment are presented below:

| | June 30, 2006 | December 31, 2005 |
|---|---|---|
| | (In millions) | |
| Pipelines | $16,765 | $16,447 |
| Exploration and Production | 5,901 | 5,570 |
| Marketing and Trading | 1,652 | 3,819 |
| Power | 805 | 1,176 |
| Field Services | — | 99 |
| Total segment assets | 25,123 | 27,111 |
| Corporate | 3,616 | 4,144 |
| Discontinued operations | 38 | 583 |
| Total consolidated assets | $28,777 | $31,838 |

## 14. Investments in Unconsolidated Affiliates and Related Party Transactions

We hold investments in unconsolidated affiliates which are accounted for using the equity method of accounting. Our income statement typically reflects (i) our share of net earnings directly attributable to these unconsolidated affiliates and (ii) impairments and other adjustments recorded by us. Our net ownership interest and earnings (losses) from our unconsolidated affiliates are as follows:

| | Net Ownership Interest | Earnings (Losses) from Unconsolidated Affiliates | | | |
|---|---|---|---|---|---|
| | June 30, 2006 | Quarters Ended June 30, 2006 | Quarters Ended June 30, 2005 | Six Months Ended June 30, 2006 | Six Months Ended June 30, 2005 |
| | (Percent) | (In millions) | | | |
| Domestic: | | | | | |
| Citrus Corporation | 50 | $19 | $ 18 | $ 29 | $ 33 |
| Great Lakes Gas Transmission Company | 50 | 14 | 14 | 30 | 31 |
| Four Star Oil & Gas Company[(1)] | 43 | 1 | — | 8 | — |
| Enterprise Products Partners, L.P. [(2)] | — | — | — | — | 183 |
| Other Domestic Investments | various | 5 | — | 5 | 3 |
| Total domestic | | 39 | 32 | 72 | 250 |
| Foreign: | | | | | |
| Asia Investments[(3)] | various | (7) | — | (4) | (46) |
| Central American Investments[(4)] | various | 1 | (55) | (1) | (49) |
| Other Foreign Investments | various | 19 | 4 | 30 | 16 |
| Total foreign | | 13 | (51) | 25 | (79) |
| Total earnings (losses) from unconsolidated affiliates | | $52 | $(19) | $ 97 | $171 |

(1) We acquired our interest in Four Star in connection with our acquisition of Medicine Bow in the third quarter of 2005. During the quarter and six months ended June 30, 2006, our proportionate share of Four Star's earnings was $14 million and $35 million. These amounts were reduced by amortization of our purchase cost in excess of the underlying net assets of Four Star of $13 million and $27 million during the same periods.

(2) In January 2005, we sold all of our remaining interests to Enterprise.

(3) As of June 30, 2006, consists of our investments in five power plants, one of which was sold in July 2006 and three of which are under sales contracts.

(4) As of June 30, 2006, consists of our investment in a power plant in Nicaragua, which is under a sales contract.

Impairment charges and gains and losses on sales of equity investments are included in earnings (losses) from unconsolidated affiliates. During the periods ended June 30, 2006 and 2005, our impairment charges were primarily a result of our decision to sell these investments. We also had investments that experienced declines in their fair value due to changes in economics of the investments' underlying contracts or the markets they serve. These impairment charges and gains (losses) consisted of the following for the periods ended June 30:

| Investment or Group | Quarters Ended June 30, 2006 | Quarters Ended June 30, 2005 | Six Months Ended June 30, 2006 | Six Months Ended June 30, 2005 |
|---|---|---|---|---|
| | (In millions) | | | |
| Asian power investments | $(7) | $(11) | $(7) | $(71) |
| Central American power investments | — | (57) | (2) | (57) |
| Enterprise | — | — | — | 183 |
| Other foreign investments | 2 | (16) | 2 | (17) |
| Other | — | (3) | — | (6) |
| | $(5) | $(87) | $(7) | $ 32 |

The summarized financial information below includes our proportionate share of the operating results of our unconsolidated affiliates for the periods ended June 30:

| | Quarters Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2006 | 2005 | 2006 | 2005 |
| | (In millions) | | | |
| Operating results data | | | | |
| Revenues | $346 | $404 | $685 | $752 |
| Operating expenses | 231 | 277 | 509 | 418 |
| Income from continuing operations | 59 | 50 | 51 | 209 |
| Net income[(1)] | 59 | 50 | 51 | 209 |

(1) Includes net income of $4 million and $10 million for the quarters ended June 30, 2006 and 2005, and $9 million and $14 million for the six months ended June 30, 2006 and 2005, related to our proportionate share of affiliates in which we hold a greater than 50 percent interest.

We received distributions and dividends from our investments of $57 million and $64 million for the quarters ended June 30, 2006 and 2005 and $112 million and $147 million for the six months ended June 30, 2006 and 2005.

*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 of transactions with our affiliates for the periods ended June 30:

| | Quarters Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2006 | 2005 | 2006 | 2005 |
| | (In millions) | | | |
| Operating revenue | $27 | $43 | $61 | $92 |
| Cost of sales | 3 | 2 | 4 | 6 |
| Reimbursement for operating expenses | 1 | — | 2 | 1 |
| Other income | 13 | 15 | 26 | 29 |

*Matters that Could Impact Our Investments*

*Domestic Power.* We own a 56 percent direct equity interest in a 261 MW power plant, Berkshire Power, located in Massachusetts. Previously, we fully impaired the value of this investment. However, we supply natural gas to Berkshire under a fuel management agreement in effect until June 2020. Berkshire had the ability to delay payment of 33 percent of the amounts due to us under the fuel supply agreement, up to a maximum of $49 million which Berkshire reached in March 2005. We reserved the cumulative amount of the delayed payments based on Berkshire's inability to generate adequate cash flows related to this agreement. In August 2006, we entered into an agreement to transfer our ownership interest in the plant to the project's lenders and other owners and terminate the fuel management agreement and all other obligations related to the project.

We supply gas to power plants that we partially own, including the Berkshire and MCV power projects. Due to their affiliated nature, we do not recognize mark-to-market gains or losses on these gas supply contracts to the extent of our ownership interest. In August 2006 we sold our interest in the MCV plant, which will result in a third quarter gain of approximately $13 million. In addition, we will record a loss during the third quarter on natural gas supply agreements with MCV as a result of the sale of our interest. Based on our estimates of the value of these contracts as of June 30, 2006, this loss would be approximately $135 million. This loss represents the cumulative unrecognized mark-to-market losses on these contracts. To secure our remaining obligations under the gas supply contracts, we have issued letters of credit and margin deposits to MCV for approximately $287 million and $24 million as of June 30, 2006.

*Investments in Asia and Central America.* As of June 30, 2006, we have net exposure of $192 million, including guarantees and letters of credit, with an exposure of $49 million on our remaining Asian and Central American investments. As the process of selling these assets continues, changes in the political and economic conditions could negatively impact the amount of net proceeds we expect to receive upon their sale, which may result in additional impairments.

*Investment in Bolivia.* We own an eight percent interest in the Bolivia to Brazil pipeline. As of June 30, 2006, our total exposure, including guarantees, in this pipeline project was $111 million, of which the Bolivian portion was $3 million. The Bolivian government has announced a new decree significantly increasing its interest in and control over Bolivia's oil and gas assets. We continue to monitor and evaluate, together with our partners, the potential commercial impact that recent political events in Bolivia could have on the Bolivia to Brazil pipeline. As new information becomes available or future material developments arise, we may be required to record an impairment of our investment.

*Investment in Argentina.* We own an approximate 22 percent interest in the Argentina to Chile pipeline. As of June 30, 2006, our total exposure in this pipeline project was $30 million. In July 2006, the Ministry of Economy and Production in Argentina issued a decree that significantly increases the export taxes on natural gas. We continue to evaluate, together with our partners, the potential commercial impact that this decree could have on the Argentina to Chile pipeline. As new information becomes available or future material developments arise, we may be required to record an impairment of our investment.

*Citrus.* Citrus Trading Corporation (CTC), a direct subsidiary of Citrus, in which we own a 50 percent equity interest, has filed suit against Duke Energy LNG Sales, Inc. (Duke) and PanEnergy Corp., the holding company of Duke, seeking damages of $185 million for breach of a gas supply contract and wrongful termination of that contract. Duke sent CTC notice of termination of the gas supply contract alleging failure of CTC to increase the amount of an outstanding letter of credit as collateral for its purchase obligations. In the lawsuit, CTC alleged that Duke failed to give proper notice to CTC regarding its failure to maintain the letter of credit. Duke has filed an amended counter claim in federal court joining Citrus and requested 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 has filed motions for partial summary judgment, requesting that the court find that Duke improperly asserted force majeure due to its alleged loss of gas supply and that Duke is in error in asserting that CTC breached contractual provisions that imposed resale restrictions and credit maintenance obligations. In July 2006, the court issued an order denying Duke's motion for partial summary judgment and found that Duke had waived strict compliance by CTC with the letter of credit and non-waiver provisions of the contract. The order identifies the remaining issues of disputed fact and contract interpretation to be resolved through jury trial. CTC has requested a trial date before the end of 2006. An unfavorable outcome on this matter could impact the value of our investment in Citrus, which in turn, could have an effect on us.

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

The information contained in Item 2 updates, and you should read it in conjunction with, information disclosed in our Current Report on Form 8-K dated May 12, 2006, and the financial statements and notes presented in Item 1 of this Quarterly Report on Form 10-Q.

### Overview

Our performance thus far in 2006 has been marked by a continued return to profitability and improvement in our credit metrics. Our core pipeline and production businesses have experienced solid financial performance in the first half of 2006, despite lower than expected commodity pricing and a slower than expected recovery from Hurricanes Katrina and Rita which occurred in 2005. We continue to grow these operations by maintaining our asset base as well as taking advantage of growth opportunities. Additionally, the reduction in commodity prices over the first half of 2006 benefited our marketing and trading activities by reducing our derivative liabilities in that business. Finally, we have continued to pay down debt of approximately $3 billion to date in 2006 with the proceeds from asset sales, an equity offering, and the paydown of our term loan in conjunction with restructuring our $3 billion credit facility in July 2006. Our segment results and liquidity and capital resources discussions that follow provide further discussion of the events affecting the quarter and six months ended June 30, 2006 as well as progress in each area of our business.

*What to Expect Going Forward.* For the remainder of 2006, we anticipate that our pipeline operations will continue to provide consistent operating results based on the current levels of contracted capacity, continued success in recontracting, expansion plans and the status of rate and regulatory actions. We will continue to create value in our exploration and production business through a disciplined and balanced capital investment program, managing increases in the cost of production services, and efficiency improvements. However, our ability to attain our operational and financial targets in this business is also dependent on commodity prices as well as continued successful execution of our drilling programs.

For 2007, we expect these operating trends to continue. Additionally, a substantial portion of our below market derivative contracts will expire in 2006, which should allow us to better participate in the current commodity pricing environment.

Finally, during the remainder of 2006 we will continue to pursue closing the sale of substantially all our remaining Asian, Central American, and domestic power assets, most of which are under sales contracts. We are also working to resolve other legacy issues, which should position us to achieve our net debt target (debt, less cash) of $14 billion by the end of 2006.

### Segment Results

Below are our results of operations (as measured by EBIT) by segment. Our business segments consist of our core Pipelines and Exploration and Production segments, as well as our Marketing and Trading and Power segments. Prior to 2006, we also had a Field Services segment. As of January 1, 2006, we had divested of substantially all of the assets and operations in this segment. Our segments are strategic business units that provide a variety of energy products and services. They are managed separately as each 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.

We use 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) preferred interests of consolidated subsidiaries. Our business operations consist of both consolidated businesses as well as 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 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 for the periods ended June 30:

| | Quarters Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2006 | 2005 | 2006 | 2005 |
| | (In millions) | | | |
| Pipelines | $ 335 | $ 309 | $ 813 | $ 721 |
| Exploration and Production | 163 | 176 | 362 | 359 |
| Marketing and Trading | 13 | (30) | 221 | (215) |
| Power | 10 | (2) | 13 | (41) |
| Field Services | — | (3) | — | 179 |
| Segment EBIT | 521 | 450 | 1,409 | 1,003 |
| Corporate | (34) | (12) | (34) | (102) |
| Consolidated EBIT from continuing operations | 487 | 438 | 1,375 | 901 |
| Interest and debt expense | (332) | (333) | (680) | (676) |
| Preferred interests of consolidated subsidiaries | — | (3) | — | (9) |
| Income taxes | (2) | (35) | (167) | (36) |
| Income from continuing operations | 153 | 67 | 528 | 180 |
| Discontinued operations, net of income taxes | (3) | (305) | (22) | (312) |
| Net income (loss) | $ 150 | $(238) | $ 506 | $ (132) |

**Pipelines Segment**

*Operating Results*

Below are the operating results for our Pipelines segment as well as a discussion of factors impacting EBIT for the periods ended June 30:

| | Quarters Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2006 | 2005 | 2006 | 2005 |
| | (In millions) | | | |
| Operating revenues | $ 705 | $ 653 | $ 1,542 | $ 1,421 |
| Operating expenses | (421) | (391) | (820) | (797) |
| Operating income | 284 | 262 | 722 | 624 |
| Other income | 51 | 47 | 91 | 97 |
| EBIT | $ 335 | $ 309 | $ 813 | $ 721 |
| Throughput volumes (BBtu/d) | 21,042 | 20,316 | 21,670 | 21,444 |

| | Quarter Ended June 30, | | | | Six Months Ended June 30, | | | |
|---|---|---|---|---|---|---|---|---|
| | Variance | | | | Variance | | | |
| | Revenue Impact | Expense Impact | Other Impact | EBIT Impact | Revenue Impact | Expense Impact | Other Impact | EBIT Impact |
| | Favorable/(Unfavorable) (In millions) | | | | | | | |
| Higher reservation and services revenues | $ 42 | $ — | $— | $ 42 | $101 | $ — | $— | $101 |
| Gas not used in operations, revaluations, processing revenues and other natural gas sales | 9 | (13) | — | (4) | 28 | 8 | — | 36 |
| Pipeline expansions | 18 | (2) | (4) | 12 | 37 | (4) | (5) | 28 |
| Contract restructurings/settlements | (14) | — | (1) | (15) | (43) | — | (1) | (44) |
| Hurricanes Katrina and Rita | — | (8) | — | (8) | — | (18) | — | (18) |
| Higher depreciation expense | — | (6) | — | (6) | — | (8) | — | (8) |
| Higher pipeline integrity expense | — | (6) | — | (6) | — | (7) | — | (7) |
| Other[(1)] | (3) | 5 | 9 | 11 | (2) | 6 | — | 4 |
| Total impact on EBIT | $ 52 | $(30) | $ 4 | $ 26 | $121 | $(23) | $(6) | $ 92 |

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

*Higher Reservation and Other Services Revenues.* During the quarter and six months ended June 30, 2006, our reservation revenues increased primarily due to the termination, effective December 31, 2005, of reduced tariff rates to certain customers under the terms of EPNG's FERC-approved systemwide capacity allocation proceeding, an increase in EPNG's tariff rates which are subject to refund and which became effective on January 1, 2006 and sales of additional firm capacity on several of our pipeline systems compared to the same periods in 2005. In addition, our usage revenues increased due to increased activity on our pipeline systems under various interruptible services provided under their tariffs.

*Gas Not Used in Operations, Revaluations, Processing Revenues and Other Natural Gas Sales.* During the first six months of 2006, sales of excess system supply gas on our ANR pipeline system and a decrease in the index prices used to value the net imbalance position on several of our pipeline systems at December 31, 2005, resulted in favorable impacts on our operating results. These favorable impacts were partially offset by sales of natural gas made available by ANR's storage realignment project during the first quarter of 2005. We anticipate that the overall activity in this area will continue to vary based on factors such as rate actions, some of which have already been implemented, the efficiency of our pipeline operations, natural gas prices and other factors. For a further discussion of our gas not used in operations, revaluations, processing revenues and other natural gas sales, see our Current Report on Form 8-K dated May 12, 2006.

*Pipeline Expansions.* In January 2005, Phase I of the Cheyenne Plains Gas Pipeline Company, L.L.C. system was fully placed in service and Phase II of this project was placed in service in December 2005. As a result, our revenues increased by $5 million and $15 million and overall EBIT increased by $5 million and $14 million during the quarter and six months ended June 30, 2006 compared to the same periods in 2005.

In February 2006, the Elba Island LNG expansion was placed in service resulting in an increase in our operating revenues. This increase was partially offset by a reduction in other income due to amounts capitalized in 2005 related to an allowance for funds used during construction of the expansion. This expansion is estimated to increase our revenues by approximately $27 million in 2006 and $29 million annually thereafter.

In March 2006, the Piceance Basin project on our Wyoming Interstate Company, Ltd. system was completed and the related compression was completed in May 2006. This project is estimated to increase our revenues by $9 million in 2006 and approximately $20 million annually thereafter.

In May 2006, the FERC granted certificate authorization for TGP's proposed Northeast ConneXion-New England project. This project will add 108 MMcf/d of incremental firm transportation capacity to the New England region from Gulf of Mexico supply sources. Estimated costs to complete the project are approximately $111 million and the anticipated in-service date is November 2007. The expansion is estimated to increase our revenues by $6 million in 2007 and $37 million annually thereafter.

In June 2006, we received permission from the FERC to construct approximately 177 miles of pipeline to connect our Elba Island facility with markets in Georgia and Florida. The project will consist of three phases with a total capital cost of approximately $320 million and a total contract level of 500 MMcf/d. Phase I has an estimated in service date of May 2007. Upon completion of all phases, our revenues are estimated to increase by approximately $62 million annually.

*Contract Restructurings/Settlements.* During the second quarter of 2005, ANR received a settlement of two transportation agreements previously rejected in the bankruptcy of USGen New England, Inc. In March 2005, ANR completed the restructuring of its transportation contracts with one of its shippers on its southwest and southeast legs as well as the restructuring of a related gathering contract. These transactions increased revenues and EBIT by approximately $15 million and $44 million during the second quarter and six months ended June 30, 2005.

*Hurricanes Katrina and Rita.* We recorded approximately $8 million and $18 million in higher operation and maintenance expenses during the quarter and six months ended June 30, 2006 and anticipate recording additional expenses of approximately $8 million for the remainder of 2006. For a further discussion of the impact of these hurricanes on our capital expenditures, see Capital Resources and Liquidity below.

*Higher Depreciation Expense.* Depreciation expense was higher for the quarter and six months ended June 30, 2006 compared to the same periods in 2005 primarily due to higher depreciation rates applied to EPNG's property, plant and equipment following the effective date of its rate case.

*Pipeline Integrity Costs.* As of January 1, 2006, we had adopted an accounting release issued by the FERC that requires us to begin expensing certain costs our interstate pipelines incur related to their pipeline integrity programs. Prior to adoption, we capitalized these costs as part of our property, plant and equipment. During the quarter and six months ended June 30, 2006, we expensed approximately $6 million and $7 million as a result of the adoption of this accounting release. We anticipate we will expense additional costs of approximately $21 million for the remainder of the year.

*Other Regulatory Matter.* In May 2006, CIG filed a request with the FERC to change the effective date of new rates from January 1, 2007 to February 1, 2007 to allow for continued settlement discussions with its customers. This request was granted by the FERC. In June 2006, CIG filed a petition with the FERC to amend its filing requirement and to approve a settlement reached with its customers to be effective October 1, 2006. This settlement provides for an annual revenue increase of approximately $6 million and a sharing mechanism to encourage additional fuel savings. CIG's petition to amend the filing requirement and to approve the settlement was unopposed by the parties and FERC staff. The outcome of this rate case and its impact on revenues cannot be predicted with certainty at this time.

**Exploration and Production Segment**

*Overview*

Our Exploration and Production segment conducts our natural gas and oil exploration and production activities. Our operating results in this segment are driven by a variety of factors, including the ability to locate and develop economic natural gas and oil reserves, extract those reserves with the lowest possible production costs, sell the products at attractive prices and minimize our total administrative costs.

We manage this business with the goal of creating shareholder value through disciplined capital allocation, cost control and portfolio management. Our natural gas and oil reserve portfolio blends slower decline rate, typically longer-lived assets in our Onshore region with steeper decline rate, shorter-lived assets in our Texas Gulf Coast and Gulf of Mexico and south Louisiana regions. We believe the combination of our assets in these regions provides significant near-term cash flow while providing consistent opportunities for high-return investments.

*Significant Operational Factors Since December 31, 2005*

- *Higher realized prices.* We continued to benefit from a strong commodity pricing environment in the first six months of 2006. Realized natural gas prices, which include the impact of our hedges, increased six percent while oil, condensate and NGL prices increased 37 percent compared to the first six months of 2005.

- *Average daily production of 707 MMcfe/d (excluding 68 MMcfe/d from our equity investment in Four Star).* Our consolidated average daily equivalent production volumes have been lower than expected due to continued shut-in production volumes in our Gulf of Mexico and south Louisiana region caused by hurricanes in the Gulf of Mexico during 2005 as well as delays in the installation of new facilities. However, when including our proportionate share of production volumes from our equity investment in Four Star, average daily equivalent production volumes were level when compared with the first six months of 2005. Our production results by region were as follows during the first six months of 2006:

  *Onshore.* We have continued to increase production volumes as a result of our successful drilling and acquisition programs.

  *Gulf of Mexico and south Louisiana.* Since the end of 2005, production in our Gulf of Mexico and south Louisiana region has increased as we brought on-line several new discoveries and continued to bring shut-in volumes from the hurricanes back on-line. During the first six months of 2006, the negative impact of shut-in volumes from the hurricanes was approximately 21 MMcfe/d. Approximately 13 MMcfe/d remains shut-in, which we expect to bring back on-line during the remainder of 2006. In addition, our new discoveries at West Cameron Blocks 75 and 62 came on-line later than expected which also negatively impacted our first quarter anticipated volumes by an estimated 20 MMcfe/d and our second quarter anticipated volumes by an estimated 13 MMcfe/d.

  *Texas Gulf Coast.* Our capital program in this region has stabilized production volumes over the last three quarters. In the second quarter of 2006, we completed the sale of certain non-strategic south Texas natural gas and oil properties for approximately $74 million. These properties had an average daily production of approximately 5 MMcfe/d and remaining reserves of approximately 16 Bcfe at the time of the sale.

  *Brazil.* Average daily production volumes decreased to 27 MMcfe/d in 2006 from 54 MMcfe/d during the same period in 2005 due to a contractual reduction in 2006 of our ownership interest in Uno Paso from 79 percent to 35 percent. In July 2006, we entered into an agreement to sell some of our non-producing natural gas and oil properties, which we expect to close by the end of 2006 for approximately $38 million.

- *Capital expenditures.* Our capital expenditures totaled $531 million, which includes $46 million of accrued capital expenditures.

- *Drilling results.* Our drilling results by region in 2006 were as follows:

  *Onshore.* We experienced a 100 percent success rate on 214 gross wells drilled resulting in production growth in the Rockies, Black Warrior Basin, Arklatex and Arkoma operating areas.

  *Gulf of Mexico and south Louisiana.* Overall, we experienced a 100 percent success rate on eight gross wells drilled. In May 2006, we brought our West Cameron Blocks 75 and 62 discoveries in the Gulf of Mexico and our two Long Point wells in Vermillion Parish, Louisiana on-line.

*Texas Gulf Coast.* We experienced a 90 percent success rate on 20 gross wells drilled. Continued success with the Wilcox (Renger Field) exploitation program in Lavaca County, Texas, saw the development of additional pay zones within the field area. The shallow Vicksburg development program in Starr and Hidalgo Counties, Texas provided consistent results on existing base properties.

*International.* In Brazil, we recompleted two wells in our Pescada-Arabaiana Field. We signed a rig contract and are preparing to drill two exploratory wells in the vicinity of the Pinauna Field scheduled for the second half of 2006. The submitted plan of development on our 17-well development program in the Pinauna Field will be reviewed to incorporate the technical results of these two exploratory wells.

In Egypt, we were awarded the South Mariut Block for $3 million in April 2006, and agreed to a $22 million firm working commitment over three years. The block is about 1.1 million acres and is located onshore in the western part of the Nile Delta.

*Outlook for 2006*

For 2006, we anticipate the following:

- Capital expenditures between $475 million and $525 million for the remainder of 2006;
- Average daily production volumes for the year to average at the low end of the range of approximately 755 MMcfe/d to 780 MMcfe/d, which excludes approximately 70 MMcfe/d from our equity interest in Four Star;
- Average cash operating costs of approximately $1.64/Mcfe to $1.71/Mcfe for the year;
- A unit of production depletion rate of between $2.25/Mcfe and $2.30/Mcfe in the third quarter of 2006 compared with $2.24/Mcfe in the second quarter of 2006 and;
- Continued industry-wide increases in drilling and oilfield service costs that will require constant monitoring of capital spending programs and a mitigation effort designed to manage and improve field efficiency.

*Price Risk Management Activities*

We enter into derivative contracts on our natural gas and oil production to stabilize cash flows, reduce the risk of downward commodity price movements on commodity sales and protect the economic assumptions associated with our capital investment programs. During the second quarter of 2006, we entered into additional derivative contracts on our 2006 and 2007 natural gas production. The following table and discussion that follows shows, as of June 30, 2006, the contracted volumes and the minimum, maximum and average prices we will receive under these contracts when combined with the sale of the underlying production:

| | **Fixed Price Swaps(1)** | | **Floors(1)** | | **Ceilings(1)** | | **Basis Swaps(1)(3)** |
|---|---|---|---|---|---|---|---|
| | **Volumes** | **Price** | **Volumes** | **Price** | **Volumes** | **Price** | **Volumes** |
| *Natural Gas(2)* | | | | | | | |
| 2006 | 43 | $ 6.15 | — | — | — | — | 49 |
| 2007 | 5 | $ 3.56 | 130 | $8.00 | 130 | $16.02 | 110 |
| 2008 | 5 | $ 3.42 | — | — | — | — | — |
| 2009-2012 | 16 | $ 3.74 | — | — | — | — | — |
| *Oil* | | | | | | | |
| 2006 | 192 | $35.15 | — | — | — | — | — |
| 2007 | 192 | $35.15 | — | — | — | — | — |

(1) Volumes presented are TBtu for natural gas and MBbl for oil. Prices presented are per MMBtu of natural gas and per Bbl of oil.

(2) The hedged natural gas prices in the table represent the price on the hedge contract when it was entered or the price on the day it was designated as a hedge. In 2006, the average cash price under these hedge contracts when they settle is approximately $3.95 per MMBtu.

(3) Our basis swaps effectively "lock-in" locational price differences on a portion of our natural gas production in Texas and Oklahoma.

Our natural gas fixed price swap, floor and ceiling contracts in the table above are designated as accounting hedges and include historical contracts that are significantly below the current market price for natural gas. Gains and losses associated with these natural gas contracts are deferred in accumulated other comprehensive income and will be recognized in earnings upon the sale of the related production at market prices, resulting in a realized price that is approximately equal to the hedged price. Changes in the fair value of our natural gas basis swaps and oil contracts are marked-to-market in earnings each period.

*Operating Results and Variance Analysis*

The tables below and the discussion that follows provide the operating results and analysis of significant variances in these results during the periods ended June 30:

| | Quarters Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2006 | 2005 | 2006 | 2005 |
| | (In millions) | | | |
| Operating Revenues: | | | | |
| Natural gas | $ 326 | $ 354 | $ 692 | $ 707 |
| Oil, condensate and NGL | 118 | 96 | 208 | 181 |
| Other | 18 | 2 | 28 | 3 |
| Total other operating revenues | 462 | 452 | 928 | 891 |
| Operating Expenses: | | | | |
| Depreciation, depletion and amortization | (156) | (157) | (302) | (303) |
| Production costs[1] | (79) | (59) | (143) | (114) |
| Cost of products and services[2] | (22) | (12) | (44) | (25) |
| General and administrative expenses | (41) | (43) | (83) | (84) |
| Other | (3) | (6) | (4) | (10) |
| Total operating expenses | (301) | (277) | (576) | (536) |
| Operating income | 161 | 175 | 352 | 355 |
| Other income[3] | 2 | 1 | 10 | 4 |
| EBIT | $ 163 | $ 176 | $ 362 | $ 359 |

| | Quarters Ended June 30, | | | Six Months Ended June 30, | | |
|---|---|---|---|---|---|---|
| | 2006 | 2005 | Percent Variance | 2006 | 2005 | Percent Variance |
| *Consolidated volumes, prices and costs per unit:* | | | | | | |
| Natural gas | | | | | | |
| Volumes (MMcf) | 53,638 | 57,790 | (7)% | 105,667 | 113,948 | (7)% |
| Average realized prices including hedges ($/Mcf)[4] | $ 6.08 | $ 6.13 | (1)% | $ 6.55 | $ 6.20 | 6% |
| Average realized prices excluding hedges ($/Mcf)[4] | $ 6.34 | $ 6.35 | —% | $ 7.05 | $ 6.03 | 17% |
| Average transportation costs ($/Mcf) | $ 0.22 | $ 0.17 | 29% | $ 0.23 | $ 0.17 | 35% |
| Oil, condensate and NGL | | | | | | |
| Volumes (MBbls) | 1,958 | 2,260 | (13)% | 3,703 | 4,396 | (16)% |
| Average realized prices including hedges ($/Bbl)[4] | $ 60.64 | $ 42.39 | 43% | $ 56.22 | $ 41.16 | 37% |
| Average realized prices excluding hedges ($/Bbl)[4] | $ 60.64 | $ 43.07 | 41% | $ 56.85 | $ 41.68 | 36% |
| Average transportation costs ($/Bbl) | $ 0.80 | $ 0.59 | 36% | $ 1.01 | $ 0.67 | 51% |
| Total equivalent volumes | | | | | | |
| MMcfe | 65,386 | 71,351 | (8)% | 127,886 | 140,327 | (9)% |
| MMcfe/d | 719 | 784 | (8)% | 707 | 775 | (9)% |
| Production Costs ($/Mcfe) | | | | | | |
| Average lease operating cost | $ 0.87 | $ 0.76 | 14% | $ 0.81 | $ 0.69 | 17% |
| Average production taxes | 0.33 | 0.07 | 371% | 0.31 | 0.13 | 138% |
| Total production cost[1] | $ 1.20 | $ 0.83 | 45% | $ 1.12 | $ 0.82 | 37% |
| Average general and administrative cost ($/Mcfe) | $ 0.62 | $ 0.61 | 2% | $ 0.64 | $ 0.60 | 7% |
| Unit of production depletion cost ($/Mcfe) | $ 2.24 | $ 2.05 | 9% | $ 2.22 | $ 2.02 | 10% |
| *Unconsolidated affiliate volumes (Four Star)*[3] | | | | | | |
| Natural gas (MMcf) | 4,456 | | | 8,963 | | |
| Oil, condensate and NGL (MBbls) | 260 | | | 569 | | |
| Total equivalent volumes | | | | | | |
| MMcfe | 6,015 | | | 12,375 | | |
| MMcfe/d | 66 | | | 68 | | |

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

(2) Includes transportation costs.

(3) Includes equity earnings and volumes for our investment in Four Star. Our equity interest in Four Star was acquired in connection with our acquisition of Medicine Bow in the third quarter 2005.

(4) Prices are stated before transportation costs.

| | Quarter Ended June 30, 2006 | | | | Six Months Ended June 30, 2006 | | | |
|---|---|---|---|---|---|---|---|---|
| | Variance | | | | Variance | | | |
| | Operating Revenue | Operating Expense | Other | EBIT | Operating Revenue | Operating Expense | Other | EBIT |
| | Favorable/(Unfavorable) (In millions) | | | | | | | |
| *Natural Gas Revenue* | | | | | | | | |
| Higher realized prices in 2006 | $ — | $ — | $ — | $ — | $107 | $ — | $ — | $107 |
| Impact of hedges | (1) | — | — | (1) | (72) | — | — | (72) |
| Lower volumes in 2006 | (27) | — | — | (27) | (50) | — | — | (50) |
| *Oil, Condensate and NGL Revenue* | | | | | | | | |
| Higher realized prices in 2006 | 34 | — | — | 34 | 56 | — | — | 56 |
| Impact of hedges | 1 | — | — | 1 | — | — | — | — |
| Lower volumes in 2006 | (13) | — | — | (13) | (29) | — | — | (29) |
| *Depreciation, Depletion and Amortization Expense* | | | | | | | | |
| Higher depletion rate in 2006 | — | (11) | — | (11) | — | (24) | — | (24) |
| Lower production volumes in 2006 | — | 12 | — | 12 | — | 25 | — | 25 |
| *Production Costs* | | | | | | | | |
| Higher lease operating costs in 2006 | — | (3) | — | (3) | — | (7) | — | (7) |
| Higher production taxes in 2006 | — | (17) | — | (17) | — | (22) | — | (22) |
| *General and Administrative Expenses* | — | 2 | — | 2 | — | 1 | — | 1 |
| *Other* | | | | | | | | |
| Earnings from investment in Four Star | — | — | 1 | 1 | — | — | 8 | 8 |
| Processing plants | 14 | (10) | — | 4 | 23 | (16) | — | 7 |
| Change in fair value of oil and basis swaps | 2 | — | — | 2 | 2 | — | — | 2 |
| Other | — | 3 | — | 3 | — | 3 | (2) | 1 |
| *Total Variances* | $ 10 | $(24) | $ 1 | $(13) | $ 37 | $(40) | $ 6 | $ 3 |

*Operating revenues.* During 2006, we continued to benefit from a strong commodity price environment for natural gas and oil, condensate and NGL. While our hedges impacted our realized prices by a comparable amount of $14 million for the quarter ended June 30, 2006 and 2005, we had a $55 million hedging loss for the six months ended June 30, 2006 compared to a hedging gain of $17 million for the six months ended June 30, 2005. Although our 2006 and 2005 production volumes benefited from acquisitions in 2005, overall production volumes decreased in our Texas Gulf Coast and Gulf of Mexico and south Louisiana regions due to natural declines coupled with a lower capital spending program in these areas over the last several years. Also, our Gulf of Mexico and south Louisiana region production was impacted by Hurricanes Katrina and Rita in 2005, while the Texas Gulf Coast region was impacted by mechanical well failures. Our production in Brazil decreased due to the contractual reduction of our ownership interest in UnoPaso in 2006.

*Depreciation, depletion and amortization expense.* During 2006, our depreciation, depletion, and amortization expense has been relatively level compared to the same periods in 2005. The impact of higher depletion rates as a result of higher finding and development costs and the cost of acquired reserves was offset by lower production volumes.

*Production costs.* In 2006, our lease operating costs increased primarily due to higher maintenance, repair and workover costs compared to 2005. Additionally, production taxes increased as compared to 2005 as a result of higher Brazilian production taxes and lower tax credits in Texas and Utah taken in 2006 compared to 2005.

*General and administrative expenses.* Our general and administrative expenses remained relatively level during 2006 compared to the same periods in 2005. While labor related costs and corporate overhead allocations decreased, we incurred higher environmental costs from our processing facilities and higher legal costs.

## Marketing and Trading Segment

Our Marketing and Trading segment's primary focus is to market our Exploration and Production segment's natural gas and oil production and to manage the company's overall price risks primarily through the use of natural gas and oil derivative contracts. Historically, this segment has also managed a portfolio of power derivatives and contracts, as well as other structured commodity-based transactions. We continue to evaluate potential opportunities to assign or otherwise divest of a number of our contracts, including our legacy natural gas derivative and transportation-related positions. Any future liquidations may impact our cash flows and financial results. For further discussion of our remaining contracts in this segment, see our Current Report on Form 8-K dated May 12, 2006.

*Operating Results*

The tables below and the discussion that follows provide the overall operating results and significant factors by contract type that affected the profitability of this segment during the periods ended June 30:

| | Quarters Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2006 | 2005 | 2006 | 2005 |
| | (In millions) | | | |
| *Overall EBIT:* | | | | |
| Gross margin[1] | $ 18 | $(21) | $223 | $(196) |
| Operating expenses | (10) | (11) | (15) | (22) |
| Operating income (loss) | 8 | (32) | 208 | (218) |
| Other income, net[2] | 5 | 2 | 13 | 3 |
| EBIT | $ 13 | $(30) | $221 | $(215) |
| *Gross Margin by Significant Contract Type:* | | | | |
| *Production-Related Natural Gas and Oil Derivative Contracts* | | | | |
| Changes in fair value of swaps and options | $ 27 | $(12) | $189 | $(118) |
| *Contracts Related to Legacy Trading Operations* | | | | |
| *Natural gas contracts:* | | | | |
| Transportation-related contracts: | | | | |
| Demand charges | (34) | (40) | (69) | (79) |
| Settlements | 17 | 21 | 37 | 48 |
| Changes in fair value of other natural gas derivative contracts | (18) | 93 | 29 | 119 |
| *Power contracts:* | | | | |
| Change in fair value of power derivatives, excluding Cordova | 26 | (22) | 37 | (72) |
| Changes in fair value of Cordova tolling agreement[3] | — | (78) | — | (111) |
| Favorable resolution of bankruptcy claim[4] | — | 17 | — | 17 |
| Total gross margin | $ 18 | $(21) | $223 | $(196) |

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

(2) Primarily represents interest on cash margin deposits.

(3) In the fourth quarter of 2005, we completed the assignment of this agreement to Constellation Energy Commodities Group Inc. (Constellation). During the first six months of 2005, forecasted natural gas prices increased relative to power prices, resulting in a decrease in fair value of the contract.

(4) During 2005, we received payment on Mohawk River Funding III's bankruptcy claim with USGen New England and recognized a gain of $17 million.

*Production-Related Natural Gas and Oil Derivative Contracts*

Our production-related natural gas and oil derivative contracts consist of various swap and option contracts. These contracts are in addition to the contracts in our Exploration and Production segment. The fair value of these contracts is impacted by changes in commodity prices from period to period and is marked-to-market in our results. Decreases in commodity prices favorably impacted our EBIT during 2006, whereas increases in commodity prices negatively impacted our EBIT during 2005.

During the second quarter of 2006, we entered into contracts to effectively eliminate the price risk on certain option contracts entered into in 2004 and 2005 related to our 2007 natural gas production. Our Exploration and Production segment also entered into new option contracts in conjunction with these terminations. Additionally, in February 2006 we entered into basis swaps related to 6 TBtu of anticipated 2006 natural gas production of which 4 TBtu remain as of June 30, 2006. These basis swaps provide price protection on changes in locational price differences in south Texas.

*Contracts Related to Legacy Trading Operations*

*Natural gas transportation-related contracts.* During 2006 and 2005, declining price differentials between the receipt and delivery points under our transportation-related contracts limited our ability to use the contracted capacity under these contracts. The following table is a summary of our demand charges (in millions) and our percentage of recovery of these charges for the periods ended June 30:

| | Quarters Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2006 | 2005 | 2006 | 2005 |
| *Alliance:* | | | | |
| Demand charges | $16 | $16 | $32 | $32 |
| Recovery | 66% | 67% | 43% | 66% |
| *Enterprise Texas:* | | | | |
| Demand charges | $ 4 | $ 7 | $ 9 | $14 |
| Recovery | 40% | 41% | 43% | 47% |
| *Other:* | | | | |
| Demand charges | $14 | $17 | $28 | $33 |
| Recovery | 36% | 58% | 70% | 68% |

*Other natural gas derivative contracts.* Our exposure to the volatility of natural gas prices as it relates to our other natural gas derivative contracts varies from period to period based on whether we purchase more or less natural gas than we sell under these contracts. Because we had the right to purchase more natural gas at fixed prices than we had the obligation to sell under these contracts during the quarter and six months ended June 30, 2006, and because natural gas prices decreased, the fair value of these contracts decreased by $18 million and $20 million. For the same periods in 2005, the fair value of these contracts increased as natural gas prices increased. Also, our EBIT for the six months ended June 30, 2006 was favorably impacted by a $49 million gain associated with the assignment of our contracts to supply natural gas to certain municipalities in Florida.

Under certain of these contracts, we supply gas to power plants that we partially own, including our MCV power project. Due to their affiliated nature, we do not recognize gains or losses on these gas supply contracts to the extent of our ownership interest. In August 2006, our Power segment sold its interest in the MCV plant, which will result in a third quarter gain of approximately $13 million. In addition, we will record a loss during the third quarter on these natural gas supply agreements. Based on our estimated value of these contracts as of June 30, 2006, this loss would be approximately $135 million. This loss represents the cumulative unrecognized mark-to-market losses on these contracts.

*Power Contracts.* Through 2005, we divested or entered into transactions to divest of a substantial portion of our power contracts, including our (i) Cordova tolling agreement, (ii) substantially all contracts in our power portfolio and (iii) certain other contracts related to our Power segment's historical power contract restructuring business. Through these actions, we have substantially eliminated our cash and earnings exposure to power price movements. Our remaining exposure in our power portfolio is primarily related to locational differences in power prices between the Pennsylvania-New Jersey-Maryland (PJM) eastern region with those in the west PJM hub. The discussion that follows provides analysis of the impact of these contracts on our results during the quarters and six months ended June 30, 2006 and 2005.

We currently have derivative contracts with Constellation that swap the locational differences in power prices at several power plants in eastern PJM and the west PJM hub through 2013. The fair value of these contracts increased by $14 million and $28 million during the quarter and six months ended June 30, 2006 and decreased by $6 million and $13 million during the quarter and six months ended June 30, 2005 due to changes in regional power prices.

Additionally, our financial results continue to be impacted by certain basis and installed capacity positions with Morgan Stanley in the PJM power pool that we retained in conjunction with the agreement in December 2005 to assign the majority of our remaining power portfolio to Morgan Stanley. During the quarter and six months ended June 30, 2006, these retained PJM basis and installed capacity positions increased in value by $12 million and $9 million due to changes in regional power prices.

Prior to entering into the agreement in 2005 with Morgan Stanley that substantially reduced our exposure to price risk on our power contracts, our results were negatively impacted by certain power supply contracts with Morgan Stanley and by power purchase contracts which were used to manage our risk on the power supply obligation to Morgan Stanley. During the six months ended June 30, 2005, our power supply contract decreased in fair value by $90 million as a result of increasing power prices and changes in locational price differences within PJM. The fair value of the related power purchase contracts decreased by $16 million and increased by $31 million during the quarter and six months ended June 30, 2005.

**Power Segment**

As of June 30, 2006, our Power segment primarily consisted of assets in Brazil, as well as certain remaining operations in Asia, Central America and three domestic power facilities. We continue to pursue the announced sales of our remaining Asian and Central American investments and our remaining domestic power facilities. A discussion of significant developments in our power operations follows.

*Brazil*

As of June 30, 2006, our remaining exposure (including guarantees) in Brazil was approximately $578 million. Of this amount, approximately $321 million relates to our Porto Velho project and the remainder relates primarily to our Manaus and Rio Negro power plants, and our Bolivia-to-Brazil and Argentina to Chile pipelines (see further discussion in Note 14). In the first quarter of 2006, Porto Velho's steam turbine returned to service which had reduced the plant's capacity since 2004. In June 2006, we completed the sale of our investment in Araucaria to COPEL for $190 million and recognized a gain of approximately $2 million.

*Other International Power*

During the first six months of 2006 and 2005, we recorded impairments, net of gains on sales, of $9 million and $141 million based on the value expected to be received upon closing the sales of our Asian and Central American power assets. Additionally, we did not recognize earnings on certain of these assets of approximately $4 million and $8 million for the quarters ended June 30, 2006 and 2005, and $12 million and $19 million for the six months ended June 30, 2006 and 2005, as we did not believe we would be able to realize earnings from these assets based on the expected selling price of these investments.

The sale of certain of our power facilities in Hungary, Peru, Bangladesh, Panama, the Dominican Republic, Nicaragua, China, Pakistan, the Philippines and Korea has contributed to a reduction in earnings from our international power investments in 2006 as compared with the same period in 2005. We expect to complete the sale of substantially all of our remaining Asian and Central American investments during the second half of 2006. As we continue to sell these assets, changes in regional political and economic conditions could negatively impact the anticipated proceeds from the sale of these assets, which could result in additional impairments. As of June 30, 2006, we had a net exposure of approximately $192 million, including guarantees and letters of credit with an exposure of $49 million. See Item 1, Financial Statements, Note 3 for further information on our divestitures.

*Domestic Power and Other*

Subsequent to June 30, 2006, we sold our interests in the MCV power facility and a portion of a cost basis investment. We also entered into agreements to sell our interests in the Capitol District Energy Center Cogeneration Associates and Berkshire power facilities. In conjunction with these transactions, we expect to record a net gain of approximately $22 million in the third quarter of 2006. For a further discussion of this matter, see Management's Discussion, Marketing and Trading Segment.

Listed below is a further analysis of our results for the periods ended June 30:

| | Quarters Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2006 | 2005 | 2006 | 2005 |
| | (In millions) | | | |
| EBIT by Area | | | | |
| *Brazil* | | | | |
| EBIT from operations | $20 | $ 23 | $32 | $ 35 |
| *Other International Power* | | | | |
| Asia | | | | |
| Impairment related to anticipated sales | (7) | (11) | (7) | (93) |
| Gain on sale of PPN power plant | — | — | — | 22 |
| EBIT from operations | — | 5 | 1 | 15 |
| Central and Other South America | | | | |
| Impairments related to anticipated sales, net[1] | — | (70) | (2) | (70) |
| EBIT from operations | 1 | 3 | — | 10 |
| EBIT from other international plants and investments[2] | 2 | 13 | 2 | 14 |
| *Domestic Power* | | | | |
| Favorable resolution of bankruptcy claim | — | 53 | — | 53 |
| Other | (3) | (9) | (9) | 3 |
| *Other*[3] | (3) | (9) | (4) | (30) |
| EBIT | $10 | $ (2) | $13 | $(41) |

(1) Includes impairment charges and gains (losses) on the sales of investments.

(2) EBIT from other international plants and investments includes a $16 million dividend on investment fund recorded in the second quarter of 2005.

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

**Field Services Segment**

As of January 1, 2006, we had divested of substantially all of the assets and operations in this segment. For the six months ended June 30, 2005, our EBIT was primarily related to a gain of $183 million on the sale of our interest in Enterprise in January 2005.

### Corporate

Our corporate operations include our general and administrative functions as well as a telecommunications business and various other contracts and assets, all of which are immaterial to our results. The following items contributed to the increase in our EBIT loss for the quarter ended June 30, 2006 and the decrease in our EBIT loss for the six months ended June 30, 2006 as compared to the same periods in 2005:

| | Favorable (Unfavorable) Quarter Impact | Favorable (Unfavorable) Six Months Impact |
|---|---|---|
| | (In millions) | |
| Western Energy Settlement charge in 2005 | $ 2 | $ 72 |
| Lease termination in 2005 | 27 | 27 |
| Foreign currency fluctuations on Euro-denominated debt | (23) | (46) |
| Change in litigation, environmental and other liabilities | (32) | (36) |
| (Higher) lower losses on early extinguishment of debt | (3) | 20 |
| Other | 7 | 31 |
| Total impact on EBIT | $(22) | $ 68 |

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

In July 2006, we entered into a new credit agreement to restructure our $3 billion credit agreement prior to its original maturity date. As a result, in the third quarter of 2006, we anticipate recording a charge of approximately $17 million related to restructuring the credit agreement.

### Interest and Debt Expense

Below is an analysis of our interest expense for the periods ended June 30:

| | Quarters Ended June | | Six Months Ended June | |
|---|---|---|---|---|
| | 2006 | 2005 | 2006 | 2005 |
| | (In millions) | | | |
| Long-term debt, including current maturities | $326 | $324 | $662 | $660 |
| Other | 6 | 9 | 18 | 16 |
| | $332 | $333 | $680 | $676 |

Interest and debt expense for the quarter and six months ended June 30, 2006 was relatively consistent with the same periods in 2005 despite a reduction in debt of approximately $2.0 billion during the six months ended June 30, 2006. While interest decreased with the net reduction of debt, we experienced higher interest rates on variable rate debt, higher fees on our letters of credit facility and higher amortization of deferred financing costs. In July 2006, we repaid an additional $965 million under our term loan in conjunction with restructuring our $3 billion credit agreement. Assuming June 30, 2006 utilization rates, as well as the July 2006 repayment of the term loan, the new facilities and reduced borrowings would provide approximately $40 million in annualized cost savings.

### Income Taxes

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

| | Quarters Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2006 | 2005 | 2006 | 2005 |
| | (In millions, except for rates) | | | |
| Income taxes | $ 2 | $35 | $167 | $36 |
| Effective tax rate | 1% | 34% | 24% | 17% |

For a discussion of our effective tax rates and other matters impacting our income taxes, see Item 1, Financial Statements, Note 5.

### Discontinued Operations

Our loss from discontinued operations for the quarter and six months ended June 30, 2005, consisted primarily of the impairment of our interest in the Macae power facility in Brazil.

## Commitments and Contingencies

See Item 1, Financial Statements, Note 9, which is incorporated herein by reference.

## Capital Resources and Liquidity

*Debt Obligations.* During 2006, we continued to reduce our overall debt obligations using cash on hand, cash generated from operations, proceeds from asset sales and proceeds from the issuance of common stock. In July 2006 we also restructured our $3 billion credit agreement. These actions have allowed us to reduce our debt obligations by over $3 billion (including $229 million related to Macae) through July 31, 2006 from $18 billion at the end of 2005. We believe that our actions to date, current operating trends, and continued success in closing asset sales for the remainder of 2006 will allow us to meet our net debt target (debt, less cash) of $14 billion by the end of the year.

*Available Liquidity.* As of June 30, 2006, we had available liquidity as follows (in millions):

| | |
|---|---|
| Available cash | $1,585 |
| Available capacity under our credit agreements[1] | 772 |
| Net available liquidity at June 30, 2006 | $2,357 |

[1] As of June 30, 2006, we had remaining capacity of $272 million under our $3 billion credit agreement. Additionally, we have $500 million of remaining capacity under a revolving credit agreement of our subsidiary, EPEP. In May 2006, our $400 million credit facility matured unutilized.

As noted above, in July 2006, we restructured our $3 billion credit agreement. We also entered into an unsecured $500 million letter of credit facility. The impact of these transactions on our available liquidity is as follows (in millions):

| | |
|---|---|
| Term loan prepayment under existing credit agreement | $ (965) |
| Reduction of capacity under letter of credit facility | $ (250) |
| Increased revolver capacity | $ 250 |
| New unsecured revolving credit facility | $ 500 |
| Net impact on available liquidity | $ (465) |

*Expected 2006 Cash Flows.* For the remainder of 2006, we expect to continue to generate positive operating cash flows which, when supplemented with expected proceeds from asset sales will be used, in part, to fund capital expenditures for the remainder of 2006. We currently anticipate approximately $0.7 billion of capital investments in our pipeline business and $0.5 billion in our exploration and production business, intended to both maintain and grow these businesses.

As of June 30, 2006, we had debt maturities for the remainder of 2006 and for 2007 of approximately $0.2 billion and approximately $0.8 billion. In the first half of 2007, we also have approximately $0.6 billion of debt that the holders can require us to redeem which, when combined with our maturities for that year, could require us to retire up to $1.4 billion of debt.

*Significant Factors That Could Impact Our Liquidity.*

- *Cash Margining Requirements on Derivative Contracts.* A substantial portion of our natural gas fixed price swap contracts are at prices significantly below current market prices, which has resulted in us posting substantial cash margin deposits with the counterparties for the value of these instruments. During the first six months of 2006, approximately $0.7 billion of posted cash margins were returned to us, with $0.3 billion resulting from decreases in commodity prices and settlement of certain of these contracts and an additional $0.4 billion related to the assignment of our power portfolio. For the remainder of 2006, based on current prices, we expect approximately $0.3 billion in collateral to be returned to us in the form of both cash margin deposits and letters of credit.

If commodity prices increase, we could be required to post additional margin. If prices decrease, we will be entitled to recover some of this amount earlier than anticipated. Based on our derivative positions at June 30, 2006, a $0.10/MMBtu increase in the price of natural gas would result in an increase in our margin requirements by $7 million for transactions that settle for the remainder of 2006, $6 million for transactions that settle in 2007, $4 million for transactions that settle in 2008 and $5 million for transactions that settle in 2009 and thereafter.

- *Hurricanes.* We continue to assess and repair the damage caused by Hurricanes Katrina and Rita. We are part of a mutual insurance company, and are subject to certain individual and aggregate loss limits by event. The mutual insurance company has indicated that the aggregate losses for both Hurricanes Katrina and Rita will exceed the per event limits allowed under the program, and that we will not receive insurance recoveries on some of the costs we incur, which will impact our liquidity and financial results. In addition, the timing of our replacements of the damaged property and equipment may differ from the related insurance reimbursement, which could impact our liquidity from period to period. Currently, we estimate that the total repair costs related to these hurricanes will be approximately $575 million, of which we estimate approximately $325 million will be unrecoverable from insurance. Of the unrecoverable amount, we estimate that approximately $245 million will be capital related expenditures, approximately $145 million of which we expect to incur in 2006.

  Our mutual insurance company has also indicated that effective June 1, 2006, the aggregate loss limits on future events has been reduced to $500 million from $1 billion, which could further limit our recoveries on future hurricanes or other insurable events.

- *Price Risk Management Activities.* Our Exploration and Production and Marketing and Trading segments enter into derivative contracts to provide price protection on a portion of our anticipated natural gas and oil production. During the second quarter of 2006, we entered into additional derivative contracts related to our 2006 and 2007 natural gas production. The following table shows as of June 30, 2006, the contracted volumes and the minimum, maximum and average cash prices that we will receive under these contracts when combined with the sale of the underlying production. These cash prices may differ from the income impacts of our derivative contracts, depending on whether the contracts are designated as hedges for accounting purposes or not. For additional information on the income impacts of our derivative contracts, see the individual segment discussions.

| | Fixed Price Swaps(1) | | Floors(1) | | Ceilings(1) | | Basis Swaps(1)(2) |
|---|---|---|---|---|---|---|---|
| | Volumes | Average Price | Volumes | Average Price | Volumes | Average Price | Volumes |
| *Natural Gas* | | | | | | | |
| 2006 | 55 | $ 4.89 | 60 | $ 7.00 | 30 | $ 9.50 | 53 |
| 2007 | 5 | $ 3.56 | 130 | $ 8.00 | 130 | $16.02 | 110 |
| 2008 | 5 | $ 3.42 | 18 | $ 6.00 | 18 | $10.00 | — |
| 2009-2012 | 16 | $ 3.74 | 17 | $ 6.00 | 17 | $ 8.75 | — |
| *Oil* | | | | | | | |
| 2006 | 714 | $52.45 | — | — | — | — | — |
| 2007 | 192 | $35.15 | 1,009 | $55.00 | 1,009 | $60.38 | — |
| 2008 | — | — | 930 | $55.00 | 930 | $57.03 | — |

(1) Volumes presented are TBtu for natural gas and MBbl for oil. Prices presented are per MMBtu of natural gas and per Bbl of oil.

(2) These contracts effectively "lock-in" locational price differences on a portion of our natural gas production in Texas and Oklahoma.

*Overview of Cash Flow Activities for 2006 Compared to 2005*

For the six months ended June 30, 2006 and 2005, our cash flows are summarized as follows:

| | 2006 | 2005 |
|---|---|---|
| | (In billions) | |
| **Cash Flow from Operations** | | |
| *Continuing operating activities* | | |
| Net income before discontinued operations | $ 0.5 | $ 0.2 |
| Non-cash income adjustments | 0.7 | 0.6 |
| Change in broker margin and other deposits(1) | 0.7 | — |
| Change in other assets and liabilities | (0.5) | (0.8) |
| Total cash flow from operations | $ 1.4 | $ — |
| **Other Cash Inflows** | | |
| *Continuing investing activities* | | |
| Net proceeds from the sale of assets and investments | $ 0.5 | $ 0.8 |
| Other | — | 0.2 |
| | 0.5 | 1.0 |
| *Continuing financing activities* | | |
| Net proceeds from the issuance of long-term debt | — | 0.5 |
| Proceeds from issuance of common and preferred stock | 0.5 | 0.7 |
| Contribution from discontinued operations | 0.1 | 0.1 |
| | 0.6 | 1.3 |
| Total cash inflows | $ 2.5 | $ 2.3 |
| **Cash Outflows** | | |
| *Continuing investing activities* | | |
| Capital expenditures(2) | $ 1.0 | $ 0.8 |
| Net cash paid for acquisition | — | 0.2 |
| | 1.0 | 1.0 |
| *Continuing financing activities* | | |
| Payments to retire long-term debt and redeem preferred interests | 1.8 | 1.5 |
| Redemption of preferred stock of a subsidiary | — | 0.3 |
| Dividends and other | 0.1 | 0.1 |
| | 1.9 | 1.9 |
| Total cash outflows | $ 2.9 | $ 2.9 |
| Net change in cash | $(0.4) | $(0.6) |

(1) Primarily due to the return of margin in 2006. This amount includes $0.4 billion collected in conjunction with the sale of certain of our power derivatives and $0.3 billion collected as commodity prices decreased and contracts were settled.

(2) Includes $0.5 billion related to production activities and $0.5 billion related to pipeline expansion and maintenance projects for 2006.

**Commodity-based Derivative Contracts**

We use derivative financial instruments in our Exploration and Production and Marketing and Trading segments to manage the price risk of commodities. In the tables below, derivatives designated as hedges consist of instruments used primarily to hedge our natural gas and oil production. Other commodity-based derivative contracts relate to derivative contracts not designated as hedges, such as options, swaps and other natural gas and power purchase and supply contracts as well as contracts related to our historical energy trading activities. The table below details the maturity of these contracts as of June 30, 2006 and changes in these derivatives from January 1, 2006 to June 30, 2006.

| | 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 | $ 35 | $ 45 | $ — | $ — | $— | $ 80 |
| Liabilities | (151) | (44) | (31) | (11) | — | (237) |
| Total derivatives designated as hedges | (116) | 1 | (31) | (11) | — | (157) |
| Other commodity-based derivatives | | | | | | |
| Exchange-traded positions[1] | | | | | | |
| Assets | 109 | 274 | 105 | — | — | 488 |
| Liabilities | — | (11) | — | — | — | (11) |
| Non-exchange-traded positions | | | | | | |
| Assets | 128 | 133 | 57 | 53 | 13 | 384 |
| Liabilities | (324) | (533) | (274) | (256) | (7) | (1,394) |
| Total other commodity-based derivatives | (87) | (137) | (112) | (203) | 6 | (533) |
| Total commodity-based derivatives | $(203) | $(136) | $(143) | $(214) | $ 6 | $ (690) |

[1] Exchange-traded positions are those traded on active exchanges such as the New York Mercantile Exchange, the International Petroleum Exchange and the London Clearinghouse.

| | Derivatives Designated as Hedges | Other Commodity-Based Derivatives | Total Commodity-Based Derivatives |
|---|---|---|---|
| | | (In millions) | |
| Fair value of contracts outstanding at January 1, 2006 | $(653) | $(763) | $(1,416) |
| Fair value of contract settlements during the period | 159 | (30) | 129 |
| Change in fair value of contracts | 325 | 256[1] | 581 |
| Reclassification of derivatives that no longer qualify as hedges[2] | 6 | (6) | — |
| Option premiums paid | 6 | 10 | 16 |
| Net change in contracts outstanding during the period | 496 | 230 | 726 |
| Fair value of contracts outstanding at June 30, 2006 | $(157) | $(533) | $ (690) |

[1] Includes a $49 million gain associated with the assignment of our contracts to supply natural gas to certain municipalities in Florida.

[2] The loss of hedge accounting was a result of a reduction of anticipated production volumes in Brazil.

*Fair Value of Contract Settlements.* 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.

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

## Item 3. Quantitative and Qualitative Disclosures About Market Risk

This information updates, and you should read it in conjunction with, information disclosed in our Current Report on Form 8-K dated May 12, 2006, 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 Current Report on Form 8-K dated May 12, 2006 except as presented below:

### Commodity Price Risk

*Production-Related Derivatives*

Our Exploration and Production and Marketing and Trading segments attempt to mitigate commodity price risk and stabilize cash flows associated with El Paso's forecasted sales of natural gas and oil production through the use of derivative natural gas and oil swaps, basis swaps and option contracts. The table below presents the hypothetical sensitivity to changes in fair values arising from immediate selected potential changes in the quoted market prices of the derivative commodity instruments used to mitigate these market risks. We have designated certain of these derivatives as accounting hedges. Those contracts that are designated as hedges will impact our earnings when the related hedged production sales occur, and, as a result, any gain or loss on these hedging derivatives would be substantially offset by a corresponding gain or loss on the underlying hedged commodity sale, which is not included in the table. Those contracts that are not designated as hedges will impact our earnings as the fair value of these derivatives changes. Our production-related derivatives do not mitigate all of the commodity price risk related to our forecasted sales of natural gas and oil production and, as a result, we are subject to commodity price risks on our remaining forecasted natural gas and oil production.

| | | 10 Percent Increase | | 10 Percent Decrease | |
|---|---|---|---|---|---|
| | Fair Value | Fair Value | (Decrease) | Fair Value | Increase |
| Impact of changes in commodity prices on derivative commodity instruments | | | | | |
| June 30, 2006 | $(195) | $ (347) | $(152) | $ (38) | $157 |
| December 31, 2005 | $(942) | $(1,175) | $(233) | $(713) | $229 |

*Other Commodity-Based Derivatives*

Our Marketing and Trading segment also has various other financial instruments that are not utilized to mitigate the commodity price risk associated with our natural gas and oil production. Many of these contracts, which include forwards, swaps, options and futures, are long-term "legacy" derivatives that we either intend to assign to third parties or to manage until the expiration of the contracts. We measure risks from these contracts on a daily basis using a Value-at-Risk simulation. This simulation allows us to determine the maximum expected one-day unfavorable impact on the fair values of those contracts due to adverse market movements over a defined period of time within a specified confidence level and allows us to monitor our risk in comparison to established thresholds. We use what is known as the historical simulation technique for measuring Value-at-Risk. This technique simulates potential outcomes in the value of our portfolio based on market-based price changes. Our exposure to changes in fundamental prices over the long-term can vary from the exposure using the one-day assumption in our Value-at-Risk simulations. We supplement our Value-at-Risk simulations with additional fundamental and market-based price analyses, including scenario analysis and stress testing to determine our portfolio's sensitivity to underlying risks. These analyses and our Value-at-Risk simulations do not include commodity exposures related to our production-related derivatives (described above), our Marketing and Trading segment's natural gas transportation related contracts that are accounted for under the accrual basis of accounting, or our Exploration and Production segment's sales of natural gas and oil production.

Our maximum expected one-day unfavorable impact on the fair values of our other commodity-based derivatives as measured by Value-at-Risk based on a confidence level of 95 percent and a one-day holding period was $8 million and $29 million as of June 30, 2006 and December 31, 2005. Our Value-at-Risk decreased significantly during 2006 primarily due to the assignment of certain of our power and natural gas derivatives to third parties and due to decreasing volatility in natural gas and power prices during 2006. We may experience significant changes in our Value-at-Risk in the future if commodity prices continue to be volatile.

## Item 4. Controls and Procedures

### Evaluation of Disclosure Controls and Procedures

As of June 30, 2006, we carried out an evaluation under the supervision and with the participation of our management, including our Chief Executive Officer (CEO) and our Chief Financial Officer (CFO), as to the effectiveness, design and operation of our disclosure controls and procedures, as defined by the Securities Exchange Act of 1934, as amended. This evaluation considered the various processes carried out under the direction of our disclosure committee in an effort to ensure that information required to be disclosed in the SEC reports we file or submit under the Exchange Act is accurate, complete and timely.

Based on the results of this evaluation, our CEO and CFO concluded that our disclosure controls and procedures were effective as of June 30, 2006.

### Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting that have materially affected or are reasonably likely to materially affect our internal control over financial reporting during the second quarter of 2006.

## PART II — OTHER INFORMATION

### Item 1. Legal Proceedings

See Part I, Item 1, Note 9, which is incorporated herein by reference. Additional information about our legal proceedings can be found below, in Part I, Item 3 of our 2005 Annual Report on Form 10-K filed with the SEC.

*Environmental Proceedings*

*Air Permit Violation.* In March 2003, the Louisiana Department of Environmental Quality (LDEQ) issued a Consolidated Compliance Order and Notice of Potential Penalty to our subsidiary, El Paso Production Company, alleging that it failed to timely obtain air permits for specified oil and natural gas facilities. El Paso Production Company requested an adjudicatory hearing on the matter. Pursuant to discussions with LDEQ, we reached an agreement to resolve the allegations and paid $77,287 on March 17, 2006.

*Arizona Pipe-Coating.* In September 2005, the ADEQ issued a Notice of Violation (NOV) for alleged regulatory violations related to EPNG's handling of asbestos-containing coal tar enamel coating. This matter was referred to the Office of the Attorney General for the State of Arizona and we have settled this matter for $225,000.

*Natural Buttes.* In May 2003, we met with the United States EPA to discuss potential prevention of significant deterioration violations due to a de-bottlenecking modification at our facility in Utah. The EPA issued an Administrative Compliance Order and we are in negotiations with the EPA as to the appropriate penalty. In September 2005, we were informed that the EPA referred this matter to the U.S. Department of Justice. We have since entered into a tolling agreement with the United States in order to facilitate continuing settlement discussions. In May 2006, the EPA indicated that it would seek a penalty of $1.1 million largely related to an alleged excess emission from an improperly installed flare. We have reserved our anticipated settlement amount and are formulating a proposal for a supplemental environmental project, which would be conducted in lieu of any eventual penalty. We believe the resolution of this matter will not have a material adverse effect on our financial condition.

*Tucson Waste Management.* In September 2004, EPNG received a NOV from the ADEQ for an alleged failure to comply with waste management regulations at our Tucson compressor station. This matter was referred to the Office of the Attorney General for the State of Arizona and we have settled this matter for $115,000.

*Shoup Natural Gas Processing Plant.* In December 2003, El Paso Field Services, L.P. received a Notice of Enforcement (NOE) from the Texas Commission on Environmental Quality (TCEQ) concerning alleged Clean Air Act violations at its Shoup, Texas plant. The alleged violations pertained to emission limit, testing, reporting and recordkeeping issues in 2001. In December 2004, TCEQ issued an Executive Director's Preliminary Report and Petition revising the allegations and seeking a penalty of $419,650. We answered the petition disputing the allegations and the penalty. We have finalized an agreement to resolve this matter by agreeing to pay a penalty of $106,439 and to pay for a supplemental environmental project costing $95,961. We paid the penalty to TCEQ on September 2, 2005 and paid for the supplemental environmental project on May 22, 2006, resolving our liability for this matter.

### Item 1A. Risk Factors

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

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

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

Forward-looking statements are subject to risks and uncertainties. While we believe the assumptions or bases underlying the forward-looking statements are reasonable and are made in good faith, we caution that assumed facts or bases almost always vary from actual results, and these variances can be material, depending upon the circumstances. We cannot assure you that the statements of expectation or belief contained in the forward-looking statements will result or be achieved or accomplished. Important factors that could cause actual results to differ materially from estimates or projections contained in forward-looking statements are described in our 2005 Annual Report on Form 10-K. There have been no material changes in our risk factors since that report.

**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**

Proposals presented for a stockholders' vote at our Annual Meeting of Stockholders held on May 25, 2006, included the election of thirteen directors, a stockholder proposal to approve the adoption of cumulative voting as a By-law or long-term policy and a stockholder proposal to approve the amendment to the By-laws for the disclosure of executive compensation.

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

| Nominee | FOR | WITHHELD |
|---|---|---|
| Juan Carlos Braniff | 503,918,399 | 81,064,555 |
| James L. Dunlap | 571,446,582 | 13,536,371 |
| Douglas L. Foshee | 572,646,503 | 12,336,450 |
| Robert W. Goldman | 502,117,372 | 82,865,581 |
| Anthony W. Hall Jr. | 572,501,110 | 12,481,843 |
| Thomas R. Hix | 571,152,981 | 13,829,972 |
| William H. Joyce | 570,500,197 | 14,482,756 |
| Ronald L. Kuehn, Jr. | 569,560,902 | 15,422,052 |
| Ferrell P. McClean | 573,021,941 | 11,961,013 |
| J. Michael Talbert | 571,560,617 | 13,422,336 |
| Robert F. Vagt | 573,062,522 | 11,920,431 |
| John L. Whitmire | 504,895,889 | 80,087,065 |
| Joe B. Wyatt | 570,891,095 | 14,091,858 |

The stockholder proposal to approve the adoption of cumulative voting as a By-law or long-term policy and the stockholder proposal to approve the amendment to the By-laws for the disclosure of executive compensation were not approved by the stockholders with the following voting results:.

| | FOR | AGAINST | ABSTAIN |
|---|---|---|---|
| Stockholder Proposal: Approval of the Adoption of Cumulative Voting as a By-law or Long-Term Policy | 185,709,593 | 257,979,247 | 20,150,548 |
| Stockholder Proposal: Approval of the Amendment to the By-laws for the Disclosure of Executive Compensation | 221,176,737 | 231,504,680 | 11,157,972 |

## Item 5. Other Information

None.

## Item 6. Exhibits

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

| Exhibit Number | Description |
|---|---|
| 10.A | Amended and Restated Credit Agreement dated as of July 31, 2006, among El Paso Corporation Colorado Interstate Gas Company, El Paso Natural Gas Company, Tennessee Gas Pipeline Company, several banks and other financial institutions from time to time parties thereto and JPMorgan Chase Bank, N.A., as administrative agent and as collateral agent. (Exhibit 10.A to our Current Report on Form 8-K, filed with the SEC on August 2, 2006). |
| 10.B | Amended and Restated Security Agreement dated as of July 31, 2006, made by El Paso Corporation Colorado Interstate Gas Company, El Paso Natural Gas Company, Tennessee Gas Pipeline Company, the Subsidiary Grantors and certain other credit parties thereto and JPMorgan Chase Bank, N.A., not in its individual capacity, but solely as collateral agent for the Secured Parties and as the depository bank. (Exhibit 10.B to our Current Report on Form 8-K, filed with the SEC on August 2, 2006). |

| Exhibit Number | Description |
|---|---|
| 10.C | Amended and Restated Parent Guarantee Agreement dated as of July 31, 2006, made by El Paso Corporation, in favor of JPMorgan Chase Bank, N.A., as Collateral Agent. (Exhibit 10.C to our Current Report on Form 8-K, filed with the SEC on August 2, 2006). |
| 10.D | Amended and Restated Subsidiary Guarantee Agreement dated as of July 31, 2006, made by each of the Subsidiary Guarantors in favor of JPMorgan Chase Bank, N.A., as Collateral Agent. (Exhibit 10.D to our Current Report on Form 8-K, filed with the SEC on August 2, 2006). |
| 10.E | Credit Agreement dated as of July 19, 2006 among El Paso Corporation, as Borrower, Deutsche Bank AG New York Branch, as Initial Lender, Issuing Bank, Administrative Agent and Collateral Agent (Exhibit 10.A to our Current Report on Form 8-K, filed with the SEC on July 20, 2006). |
| *12 | Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividends |
| *31.A | Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 |
| *31.B | Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 |
| *32.A | Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 |
| *32.B | Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 |

Undertaking

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

## SIGNATURES

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

EL PASO CORPORATION

Date: August 7, 2006

/s/ D. Mark Leland

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

Date: August 7, 2006

/s/ John R. Sult

John R. Sult
*Senior Vice President and Controller*
*(Principal Accounting Officer)*