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

# Form 10-Q

(Mark One)

☑ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

**For the quarterly period ended September 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 October 31, 2006: 705,389,577

# 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 | NGL | = natural gas liquids |
| MBbls | = thousand barrels | TBtu | = trillion British thermal units |
| Mcf | = thousand cubic feet | | |

When we refer to natural gas and oil in "equivalents," we are doing so to compare quantities of oil with quantities of natural gas or to express these different commodities in a common unit. In calculating equivalents, we use a generally recognized standard in which one Bbl of oil is equal to six Mcf of natural gas. 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 September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2006 | 2005 | 2006 | 2005 |
| Operating revenues | $1,061 | $ 752 | $3,806 | $ 3,009 |
| Operating expenses | | | | |
| Cost of products and services | 73 | 111 | 219 | 259 |
| Operation and maintenance | 366 | 454 | 1,085 | 1,250 |
| Depreciation, depletion and amortization | 282 | 270 | 832 | 823 |
| Loss on long-lived assets | 15 | 3 | 15 | 10 |
| Taxes, other than income taxes | 69 | 69 | 203 | 190 |
| | 805 | 907 | 2,354 | 2,532 |
| Operating income (loss) | 256 | (155) | 1,452 | 477 |
| Earnings from unconsolidated affiliates | 69 | 13 | 166 | 184 |
| Other income, net | 34 | 50 | 116 | 148 |
| Interest and debt expense | (310) | (337) | (990) | (1,013) |
| Preferred interests of consolidated subsidiaries | — | — | — | (9) |
| Income (loss) before income taxes | 49 | (429) | 744 | (213) |
| Income taxes | (86) | (136) | 81 | (100) |
| Income (loss) from continuing operations | 135 | (293) | 663 | (113) |
| Discontinued operations, net of income taxes | — | (19) | (22) | (331) |
| Net income (loss) | 135 | (312) | 641 | (444) |
| Preferred stock dividends | 9 | 9 | 28 | 17 |
| Net income (loss) available to common stockholders | $ 126 | $ (321) | $ 613 | $ (461) |
| Earnings (losses) per common share | | | | |
| Basic | | | | |
| Income (loss) from continuing operations | $ 0.18 | $(0.47) | $ 0.94 | $ (0.20) |
| Discontinued operations, net of income taxes | — | (0.03) | (0.03) | (0.52) |
| Net income (loss) | $ 0.18 | $(0.50) | $ 0.91 | $ (0.72) |
| Diluted | | | | |
| Income (loss) from continuing operations | $ 0.18 | $(0.47) | $ 0.90 | $ (0.20) |
| Discontinued operations, net of income taxes | — | (0.03) | (0.03) | (0.52) |
| Net income (loss) | $ 0.18 | $(0.50) | $ 0.87 | $ (0.72) |
| Dividends declared per common share | $ 0.04 | $ 0.04 | $ 0.12 | $ 0.12 |

See accompanying notes.

## EL PASO CORPORATION

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

| | September 30, 2006 | December 31, 2005 |
|---|---|---|
| ASSETS | | |
| Current assets | | |
| Cash and cash equivalents | $ 759 | $ 2,132 |
| Accounts and notes receivable | | |
| Customers, net of allowance of $33 in 2006 and $67 in 2005 | 590 | 1,115 |
| Affiliates | 163 | 58 |
| Other | 454 | 141 |
| Assets from price risk management activities | 302 | 641 |
| Margin and other deposits held by others | 25 | 1,124 |
| Assets related to discontinued operations and held for sale | 62 | 230 |
| Deferred income taxes | 206 | 396 |
| Other | 258 | 348 |
| Total current assets | 2,819 | 6,185 |
| Property, plant and equipment, at cost | | |
| Pipelines | 20,693 | 19,965 |
| Natural gas and oil properties, at full cost | 16,439 | 15,738 |
| Other | 577 | 651 |
| | 37,709 | 36,354 |
| Less accumulated depreciation, depletion and amortization | 18,085 | 17,567 |
| Total property, plant and equipment, net | 19,624 | 18,787 |
| Other assets | | |
| Investments in unconsolidated affiliates | 2,081 | 2,473 |
| Assets from price risk management activities | 551 | 1,368 |
| Other | 2,324 | 3,025 |
| | 4,956 | 6,866 |
| Total assets | $27,399 | $31,838 |

See accompanying notes.

## EL PASO CORPORATION

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

| | September 30, 2006 | December 31, 2005 |
|---|---|---|
| LIABILITIES AND STOCKHOLDERS' EQUITY | | |
| Current liabilities | | |
| Accounts payable | | |
| Trade | $ 457 | $ 864 |
| Affiliates | 3 | 10 |
| Other | 496 | 540 |
| Short-term financing obligations, including current maturities | 885 | 986 |
| Liabilities from price risk management activities | 380 | 1,418 |
| Liabilities related to discontinued operations | 33 | 420 |
| Margin deposits held by us | 294 | 497 |
| Accrued interest | 297 | 290 |
| Other | 1,067 | 687 |
| Total current liabilities | 3,912 | 5,712 |
| Long-term financing obligations, less current maturities | 14,294 | 17,023 |
| Other | | |
| Liabilities from price risk management activities | 1,058 | 2,005 |
| Deferred income taxes | 1,557 | 1,405 |
| Other | 1,807 | 2,273 |
| | 4,422 | 5,683 |
| Commitments and contingencies | | |
| Securities of subsidiaries | 29 | 31 |
| Stockholders' equity | | |
| Preferred stock, par value $0.01 per share; authorized 50,000,000 shares; issued 750,000 shares of 4.99% convertible perpetual stock; stated at liquidation value | 750 | 750 |
| Common stock, par value $3 per share; authorized 1,500,000,000 shares; issued 704,564,119 shares in 2006 and 667,082,043 shares in 2005 | 2,114 | 2,001 |
| Additional paid-in capital | 4,833 | 4,592 |
| Accumulated deficit | (2,774) | (3,415) |
| Accumulated other comprehensive income (loss) | 20 | (332) |
| Treasury stock (at cost); 8,576,078 shares in 2006 and 7,620,272 shares in 2005 | (201) | (190) |
| Unamortized compensation | — | (17) |
| Total stockholders' equity | 4,742 | 3,389 |
| Total liabilities and stockholders' equity | $27,399 | $31,838 |

See accompanying notes.

## EL PASO CORPORATION

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

| | Nine Months September 30, | |
|---|---|---|
| | **2006** | **2005** |
| Cash flows from operating activities | | |
| Net income (loss) | $ 641 | $ (444) |
| Loss from discontinued operations, net of income taxes | (22) | (331) |
| Net income (loss) from continuing operations | 663 | (113) |
| Adjustments to reconcile net income (loss) to net cash from operating activities | | |
| Depreciation, depletion and amortization | 832 | 823 |
| Loss on long-lived assets | 15 | 10 |
| Earnings from unconsolidated affiliates, adjusted for cash distributions | 22 | 13 |
| Deferred income taxes | 47 | 23 |
| Other non-cash items | 67 | 34 |
| Change in margin and other deposits | 896 | (692) |
| Other asset and liability changes | (540) | (485) |
| Cash provided by (used in) continuing operations | 2,002 | (387) |
| Cash provided by (used in) discontinued operations | 10 | (11) |
| Net cash provided by (used in) operating activities | 2,012 | (398) |
| Cash flows from investing activities | | |
| Capital expenditures | (1,639) | (1,260) |
| Net proceeds from the sale of assets and investments | 501 | 1,113 |
| Cash paid for acquisitions, net of cash acquired | — | (1,023) |
| Net change in restricted cash | 102 | 16 |
| Other | 25 | 207 |
| Cash used in continuing operations | (1,011) | (947) |
| Cash provided by discontinued operations | 356 | 178 |
| Net cash used in investing activities | (655) | (769) |
| Cash flows from financing activities | | |
| Payments to retire long-term debt and other financing obligations | (2,992) | (1,525) |
| Net proceeds from the issuance of long-term debt and other financing obligations | 125 | 1,225 |
| Dividends paid | (108) | (85) |
| 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 | 136 | 70 |
| Other | (25) | (4) |
| Cash provided by (used in) continuing operations | (2,364) | 104 |
| Cash used in discontinued operations | (366) | (167) |
| Net cash used in financing activities | (2,730) | (63) |
| Change in cash and cash equivalents | (1,373) | (1,230) |
| Cash and cash equivalents | | |
| Beginning of period | 2,132 | 2,117 |
| End of period | $ 759 | $ 887 |

See accompanying notes.

## EL PASO CORPORATION

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

| | Quarters Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2006 | 2005 | 2006 | 2005 |
| Net income (loss) | $135 | $(312) | $641 | $(444) |
| Foreign currency translation adjustments (net of income taxes of less than $1 in 2006 and $20 and $13 in 2005) | 3 | (5) | 5 | 2 |
| Unrealized net gains (losses) from cash flow hedging activity | | | | |
| Unrealized mark-to-market gains (losses) arising during period (net of income taxes of $51 and $174 in 2006 and $180 and $269 in 2005) | 92 | (325) | 311 | (497) |
| Reclassification adjustments for changes in initial value to the settlement date (net of income taxes of $3 and $18 in 2006 and $15 and $3 in 2005) | 4 | 42 | 29 | 23 |
| Change in unrealized gains on available for sale securities, net of reclassification adjustments (net of income tax of $1 and $4 in 2006) | (2) | — | 7 | — |
| Other comprehensive income (loss) | 97 | (288) | 352 | (472) |
| Comprehensive income (loss) | $232 | $(600) | $993 | $(916) |

See accompanying notes.

## 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 (SEC). 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 September 30, 2006, and for the quarters and nine months ended September 30, 2006 and 2005, are unaudited. We derived the condensed consolidated 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 result in a significant cumulative effect to our financial statements. For additional information on our stock-based compensation awards, see Note 13.

*Accounting for Pipeline Integrity Costs.* As of January 1, 2006, we adopted an accounting release issued by the Federal Energy Regulatory Commission (FERC) that requires us to expense 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 nine months ended September 30, 2006, we expensed approximately $7 million and $14 million as a result of the adoption of this accounting release, which was approximately $0.01 per basic and fully diluted share for both the quarter and nine month periods ended September 30, 2006. We anticipate we will expense additional costs of approximately $7 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 a tax position being sustained under examination) prior to recording a benefit for their 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 that this interpretation will have on our financial statements.

*Accounting for Pension and Other Postretirement Benefits.* In September 2006, the FASB issued SFAS No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans* — an Amendment of FASB Statements No. 87, 88, 106 and 132(R). SFAS No. 158 requires companies to record an asset or liability for their pension and other postretirement benefit plans based on their funded or unfunded status. The standard also requires any deferred amounts related to unrealized gains and losses or changes in actuarial assumptions be recorded in accumulated other comprehensive income (loss), a component of stockholders' equity, until those gains and losses are realized. These deferred amounts were previously included in our pension and other postretirement assets in our balance sheets, and their reclassification to stockholders' equity will not impact our pension expense included in our income statements. Finally, the standard requires companies to measure their pension and postretirement obligations as of their year end balance sheet date beginning in 2008.

We will adopt the recognition and disclosure provisions of this standard effective December 31, 2006 and currently anticipate the adoption will result in a reduction of our pension and other postretirement assets included in other non-current assets of approximately $600 million, a reduction of our non-current deferred tax and other liabilities of approximately $200 million, and a decrease in our stockholders' equity (in accumulated other comprehensive income(loss)) of approximately $400 million. SFAS No. 158 will also require us to change the measurement date for our pension and other postretirement benefit plans from September 30, the date we currently use, to December 31 beginning in 2008.

*Fair Value Measurements.* In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements*, which provides guidance on measuring the fair value of assets and liabilities in the financial statements. We will be required to adopt the provisions of this standard no later than 2008, and are currently evaluating the impact, if any, that it will have on our financial statements.

*Evaluation of Prior Period Misstatements in Current Financial Statements.* In September 2006, the staff of the SEC released Staff Accounting Bulletin (SAB) No. 108, *Considering the Effects of Prior Year Misstatements When Quantifying Misstatements in Current Year Financial Statements.* SAB No. 108 provides guidance on how to evaluate the impact of financial statement misstatements from prior periods that have been identified in the current year. We will adopt the provisions of SAB No. 108 in the fourth quarter of 2006, and do not anticipate that it will have a material impact 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 nine months ended September 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 on January 1, 2005 and are not necessarily indicative of the operating results that would have occurred had the acquisition been consummated at that date, nor are they necessarily indicative of future operating results.

| | Quarter Ended September 30, 2005 | Nine Months Ended September 30, 2005 |
|---|---|---|
| | (In millions, except per share amounts) | |
| Revenues | $ 763 | $3,048 |
| Net loss available to common stockholders | (321) | (451) |
| Basic and diluted net loss per share | (0.50) | (0.70) |

## 3. Divestitures

*Sales of Assets and Investments*

During the nine months ended September 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 | $ 3 | $ 49 |
| Exploration and Production | 86 | — |
| Power | 438 | 468 |
| Field Services | — | 501 |
| Corporate | 2 | 121 |
| Total continuing operations[1] | 529 | 1,139 |
| Discontinued operations | 364 | 87 |
| Total proceeds | $893 | $1,226 |

[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 increased our sales proceeds by $28 million and $26 million for the nine months ended September 30, 2006 and 2005.

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

| | 2006 | 2005 |
|---|---|---|
| Pipelines | • Miscellaneous transmission lines and related measurement equipment | • Facilities located in the southeastern U.S.<br>• Interest in a gathering system in the western 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<br>• Interest in Midland Cogeneration Venture (MCV) | • Cedar Brakes I and II<br>• Interests in power plants in India, Korea, England and the U.S.<br>• Power turbines |
| 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 |

| | 2006 | 2005 |
|---|---|---|
| Discontinued | • Macae power facility in Brazil<br>• Power plant in the Philippines | • Interest in Paraxylene facility<br>• Methyl tertiary-butyl ether processing facility<br>• International natural gas and oil production properties |

In October 2006, we also sold our interests in a power facility in Indonesia, two domestic power facilities and a cost basis investment for total proceeds of approximately $90 million. In addition, we also have agreements to sell additional assets for total proceeds of approximately $100 million, including a pipeline lateral located in the northeastern United States, certain Brazilian natural gas and oil properties and interests in our remaining 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 our continuing operations 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 nine months ended September 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. The sale was completed in April 2006 and 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 for approximately $6 million. As of September 30, 2006, our only remaining power asset in discontinued operations is our Nejapa power plant which we expect to sell within the next six months. For a further discussion of our international power operations, see Note 15.

*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 our Canadian and certain other international natural gas and oil production operations.

*Petroleum Markets.* We completed the sale of these historical operations in 2005.

| | 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 September 30, 2006** | | | | | |
| Revenues | $ 28 | $ — | $— | $ — | $ 28 |
| Costs and expenses | (28) | — | — | — | (28) |
| Loss on long-lived assets | (5) | — | — | — | (5) |
| Other income | 2 | — | — | — | 2 |
| Interest and debt expense | (1) | — | — | — | (1) |
| Loss before income taxes | $ (4) | $ — | $— | $ — | (4) |
| Income taxes | | | | | (4) |
| Income from discontinued operations, net of income taxes | | | | | $ — |
| **Quarter Ended September 30, 2005** | | | | | |
| Revenues | $ 58 | $ 99 | $— | $ 26 | $ 183 |
| Costs and expenses | (54) | (89) | — | (30) | (173) |
| Gain on long-lived assets | — | — | — | 1 | 1 |
| Other income | 1 | — | — | 1 | 2 |
| Interest and debt expense | (7) | — | — | — | (7) |
| Income (loss) before income taxes | $ (2) | $ 10 | $— | $ (2) | 6 |
| Income taxes | | | | | 25 |
| Loss from discontinued operations, net of income taxes | | | | | $ (19) |
| **Nine Months Ended September 30, 2006** | | | | | |
| Revenues | $ 131 | $ — | $— | $ — | $ 131 |
| Costs and expenses | (139) | — | — | — | (139) |
| Gain (loss) on long-lived assets | (10) | 5 | — | — | (5) |
| Other income | 4 | — | — | — | 4 |
| Interest and debt expense | (14) | — | — | — | (14) |
| Income (loss) before income taxes | $ (28) | $ 5 | $— | $ — | (23) |
| Income taxes | | | | | (1) |
| Loss from discontinued operations, net of income taxes | | | | | $ (22) |
| **Nine Months Ended September 30, 2005** | | | | | |
| Revenues | $ 167 | $ 276 | $ 2 | $ 100 | $ 545 |
| Costs and expenses | (185) | (246) | (2) | (116) | (549) |
| Gain (loss) on long-lived assets | (374) | — | (5) | 4 | (375) |
| Other income | 7 | — | — | 12 | 19 |
| Interest and debt expense | (21) | — | — | — | (21) |
| Income (loss) before income taxes | $(406) | $ 30 | $ (5) | $ — | (381) |
| Income taxes | | | | | (50) |
| Loss from discontinued operations, net of income taxes | | | | | $(331) |

Assets and liabilities of discontinued operations relate to our international power operations. As of September 30, 2006 and December 31, 2005, we had total assets of approximately $34 million and $583 million classified as discontinued operations. As of September 30, 2006 and December 31, 2005, total liabilities classified as discontinued operations were approximately $33 million and $422 million.

## 4. Full Cost Ceiling Test

Under the full cost method of accounting for natural gas and oil properties, we perform quarterly ceiling tests, on an after-tax basis, to evaluate whether the carrying value of these properties exceeds the present value of future net revenues, discounted at 10 percent, plus the lower of cost or fair market value of unproved properties. Our ceiling test assessments utilize period-end natural gas and oil prices adjusted for oilfield or gas gathering hub and wellhead price differences as appropriate. Additionally, we include the impact of financial instruments designated as hedges on our natural gas and oil production in our ceiling test calculation to determine whether or not we would recognize a ceiling test charge.

Our net capitalized natural gas and oil property costs did not exceed the capitalization ceiling based on a subsequent recovery of prices from those levels that existed at September 30, 2006. Based on SEC guidelines, we considered the recovery of commodity prices subsequent to the balance sheet date to determine whether we were required to record a ceiling test charge as of September 30, 2006. As of October 26, 2006, natural gas prices had recovered to approximately $7.92/MMbtu from $4.18/MMbtu at September 30 and crude oil prices, which have less impact on us, decreased slightly from $62.91/Bbl at September 30. Using the October 26, 2006 prices, the present value of future net revenues exceeded the carrying value of our properties and we were not required to record a ceiling test charge for our domestic full cost pool. Had we utilized prices as of September 30, 2006, capitalized costs in our domestic full cost pool would have exceeded the present value of future net revenues, on an after-tax basis, by approximately $221 million. For purposes of this calculation, hedges of natural gas production as of September 30, 2006, increased the net present value of future net revenues on an after-tax basis by approximately $318 million.

## 5. 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 nine months ended September 30, 2006, our loss on long-lived assets of $15 million was due primarily to our decision to discontinue the development of several pipeline expansion projects due to changing market conditions. During the nine months ended September 30, 2005, our net loss on long-lived assets of $10 million was primarily due to a $15 million impairment recorded by our Power segment on several 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.

## 6. Income Taxes

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

| | Quarters Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2006 | 2005 | 2006 | 2005 |
| | (In millions, except rates) | | | |
| Income taxes | $ (86) | $(136) | $81 | $(100) |
| Effective tax rate | (176)% | 32% | 11% | 47% |

We compute our quarterly income taxes using a method based on applying an anticipated annual effective tax rate to our year-to-date income or loss, except for significant unusual or infrequently occurring items. Significant tax items, which may include the conclusion of income tax audits, are recorded in the period that the specific item occurs.

In 2006, the IRS audits of The Coastal Corporation's 1998-2000 tax years and El Paso's 2001 and 2002 tax years were concluded. 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 audits which resulted in the reduction of tax contingencies and the reinstatement of certain tax credits. Also, the rate was impacted by net tax amounts recognized on certain foreign investments. The totals of these amounts were $105 million and $163 million for the quarter and nine months ended September 30, 2006.

During the nine months ended September 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 is currently auditing El Paso's 2003 and 2004 tax years. We have recorded liabilities for tax contingencies associated with these audits, as well as for proceedings and examinations with other taxing authorities, which we believe are adequate. As these matters are finalized, we may be required to adjust our liability which could significantly increase or decrease our income tax expense and effective income tax rates in future periods.

### 7. 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 September 30,** | | | | |
| Income (loss) from continuing operations | $ 135 | $ 135 | $ (293) | $ (293) |
| Convertible preferred stock dividends | (9) | — | (9) | (9) |
| Income (loss) from continuing operations available to common stockholders | 126 | 135 | (302) | (302) |
| Discontinued operations | — | — | (19) | (19) |
| Net income (loss) available to common stockholders | $ 126 | $ 135 | $ (321) | $ (321) |
| Weighted average common shares outstanding | 693 | 693 | 648 | 648 |
| Effect of dilutive securities: | | | | |
| Options and restricted stock | — | 4 | — | — |
| Convertible preferred stock | — | 57 | — | — |
| Weighted average common shares outstanding and dilutive potential common shares | 693 | 754 | 648 | 648 |
| Earnings per common share: | | | | |
| Income (loss) from continuing operations | $0.18 | $0.18 | $(0.47) | $(0.47) |
| Discontinued operations, net of income taxes | — | — | (0.03) | (0.03) |
| Net income (loss) | $0.18 | $0.18 | $(0.50) | $(0.50) |

| | 2006 | | 2005 | |
|---|---|---|---|---|
| | Basic | Diluted | Basic | Diluted |
| **Nine Months Ended September 30,** | | | | |
| Income (loss) from continuing operations | $ 663 | $ 663 | $ (113) | $ (113) |
| Convertible preferred stock dividends | (28) | — | (17) | (17) |
| Income (loss) from continuing operations available to common stockholders | 635 | 663 | (130) | (130) |
| Discontinued operations | (22) | (22) | (331) | (331) |
| Net income (loss) available to common stockholders | $ 613 | $ 641 | $ (461) | $ (461) |
| Weighted average common shares outstanding | 673 | 673 | 643 | 643 |
| Effect of dilutive securities: | | | | |
| Options and restricted stock | — | 4 | — | — |
| Convertible preferred stock | — | 57 | — | — |
| Weighted average common shares outstanding and dilutive potential common shares | 673 | 734 | 643 | 643 |
| Earnings per common share: | | | | |
| Income (loss) from continuing operations | $ 0.94 | $ 0.90 | $(0.20) | $(0.20) |
| Discontinued operations, net of income taxes | (0.03) | (0.03) | (0.52) | (0.52) |
| Net income (loss) | $ 0.91 | $ 0.87 | $(0.72) | $(0.72) |

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 potentially dilutive securities consist of our employee stock options, restricted stock, convertible preferred stock, trust preferred securities, and zero coupon convertible debentures (which were paid off in April 2006). During the quarter and nine months ended September 30, 2006, certain employee stock options and our remaining trust preferred securities were antidilutive. Additionally, during the nine month period in 2006 our zero coupon convertible debentures were antidilutive. In 2005, we incurred losses from continuing operations and accordingly excluded all potentially dilutive securities from the determination of diluted earnings per share as their impact on income (loss) per common share was antidilutive. For a discussion of our capital stock activity in 2006, our stock-based compensation arrangements, and other instruments noted above, see Notes 12 and 13 as well as our Current Report on Form 8-K dated May 12, 2006.

## 8. Price Risk Management Activities

The following table summarizes the carrying value of the derivatives used in our price risk management activities as of September 30, 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.

Our derivative contracts are recorded in our financial statements at fair value. The best indication of fair value is quoted market prices. However, when quoted market prices are not available, we estimate the fair value of those derivative contracts utilizing commodity pricing data either obtained or derived from information provided by a third party pricing service. During the third quarter of 2006, we changed this third party pricing source. The impact of this change was not material to our results for the period.

| | September 30, 2006 | December 31, 2005 |
|---|---|---|
| | (In millions) | |
| Net assets (liabilities) | | |
| Derivatives designated as hedges | $ 52 | $ (653) |
| Other commodity-based derivative contracts | (653) | (763) |
| Total commodity-based derivatives[1] | (601) | (1,416) |
| Interest rate and foreign currency derivatives | 16 | 2 |
| Net liabilities from price risk management activities[2] | $(585) | $(1,414) |

[1] The decrease in the net liability during the nine months ended September 30, 2006 is primarily due to a decline in natural gas prices.

[2] Included in both current and non-current assets and liabilities on the balance sheet.

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

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

| | September 30, 2006 | December 31, 2005 |
|---|---|---|
| | (In millions) | |
| Short-term financing obligations, including current maturities[1] | $ 885 | $ 986 |
| Long-term financing obligations | 14,294 | 17,023 |
| Total | $15,179 | $18,009 |

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

As of September 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. Based on September 30, 2006 balances, approximately $9 billion of debt obligations are callable by us in 2006, an additional $300 million is callable by us in 2007, and an additional $1.2 billion is callable by us in 2008 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 September 30, 2006, we had the following changes in our long-term and short-term financing obligations:

| Company | Type | Interest Rate | Book Value Increase (Decrease) | Cash Received/ (Paid) |
|---|---|---|---|---|
| | | | (In millions) | |
| *Issuances* | | | | |
| El Paso Exploration & Production Company | Revolving credit facility due 2010 | LIBOR + 1.25% | $ 125 | $ 125 |
| | *Increases through September 30, 2006* | | $ 125 | $ 125 |
| *Repayments, repurchases, retirements and other* | | | | |
| Coastal Finance I | Trust originated preferred securities | 8.375% | $ (300) | $ (300) |
| El Paso | Zero coupon convertible debentures | — | (615) | (615) |
| El Paso | Euro notes | 5.75% | (26) | (26) |
| El Paso Exploration & Production Company | Revolving credit facility | LIBOR + 1.875% | (500) | (500) |
| El Paso | Notes | 6.50% | (110) | (110) |
| Macae[1] | Non-recourse notes | Variable | (229) | (229) |
| El Paso | Term Loan | LIBOR + 2.75% | (1,225) | (1,225) |
| El Paso | Senior Notes | 7.50% | (183) | (183) |
| El Paso | Notes | 7.50% | (22) | (22) |
| Other | Long-term debt | Various | 26 | (11) |
| | *Decreases through September 30, 2006* | | $(3,184) | $(3,221) |

(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 debentures, which increased the principal balance of long-term debt each period. During the nine months ended September 30, 2006 and 2005, the accretion recorded in interest expense was $4 million and $19 million. During the nine months ended September 30, 2006 and 2005, we redeemed $615 million and $236 million of our zero coupon convertible 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 September 30, 2006, we had available capacity under our credit agreements of approximately $1 billion. Of this amount, $375 million is related to the $500 million revolving credit agreement of our subsidiary, El Paso Exploration & Production Company (EPEP), and the remainder is available under our $1.75 billion credit agreement and our unsecured revolving credit facility. In May 2006, our $400 million credit facility matured unutilized.

*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. In conjunction with the restructuring, we recorded a third quarter charge 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 the new 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 which mature in July 2011. We pay LIBOR plus 2.00% on any amounts borrowed under the deposit 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 and;

(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, we remain 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 July 2009.

*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 LIBOR or a base rate.

*Letters of Credit.* As of September 30, 2006, we had total outstanding letters of credit of approximately $1.6 billion. Approximately $1.1 billion of letters of credit were issued under the $1.75 billion credit agreement, and substantially all of the remaining letters of credit were issued under the $500 million unsecured revolving credit facility.

## 10. 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 November 2006, the parties executed a definitive settlement agreement in which the parties agreed to settle these class action lawsuits, subject to final court approval. Under the terms of the settlement, 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 settlement.

*Derivative Litigation.* Three shareholder derivative actions were filed, including two in federal court in Houston and one in state court in Houston. These cases generally alleged the same claims pled in the consolidated shareholder litigation. All of these cases have now been either settled or dismissed. In the settlement of the state court action, the settlement 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.

*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 similar to those pled in the consolidated shareholder litigation 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). Formal discovery in this lawsuit is currently stayed.

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 believe 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 have filed for the review of these decisions 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. 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. We have reached a tentative settlement with the plaintiffs subject to execution of definitive agreements and court approval.

The second set of cases, involving similar allegations on behalf of commercial and residential customers, were 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*, dismissed and have been appealed. The third set of cases also involve similar allegations on behalf of certain purchasers of natural gas. These include purported class action lawsuits styled *Leggett et al. v. Duke Energy Corporation et al.* (filed in Chancery Court of Tennessee in January 2005); *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); *Learjet, Inc. v. Oneok Inc.* (filed in state court in Wyandotte County, Kansas in September 2005); *Breckenridge, et al v. Oneok Inc., et al.* (filed in state court in Denver County, Colorado in May 2006) and *Missouri Public Service Commission v. El Paso Corporation et al* (filed in the circuit court of Jackson County, Missouri at Kansas City in October 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 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. In October 2006, the U.S. District Judge issued an order dismissing all mismeasurement claims against all defendants.

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. The plaintiffs currently seek certification of a class of royalty owners in wells on non-federal and non-Native American lands 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. The 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 this lawsuit and claim are not currently determinable.

*Hurricane Litigation.* We have been named in three class action petitions for damages filed in the United States 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., Charles Villa Jr., et al. v. Columbia Gulf Transmission Company, et al.* (filed in 2005) and *Henry and Hattie Bands et al. v. Columbia Gulf Transmission Company et al.* (filed in August 2006) 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 Barasich and Bands lawsuits allege damages associated with Hurricane Katrina. The Villa lawsuit alleges damages associated with Hurricanes Katrina and Rita. The court consolidated the Villa and Barasich cases and issued an order dismissing the cases for failure to state a claim on which relief could be granted. The Bands case was not consolidated at the time the Barasich and Villa dismissal order was issued and the defendants are seeking to have it dismissed on the same grounds. Our costs and legal exposure related to this lawsuit and claim 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. 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 also been settled subject to court approval, after a fairness hearing scheduled for March 2007. 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 are not currently determinable.

*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 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 and have commenced discussions with the DOJ and SEC in an attempt to resolve these investigations.

*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 has made significant progress towards a tentative settlement with its customers. The outcome of this or any additional rate case cannot be predicted with certainty at this time.

*CIG Rate Case.* In August 2006, the FERC approved a settlement reached with CIG's customers to be effective October 1, 2006. The settlement establishes system-wide base rates through at least September 2010, but no later than September 2011, and establishes a sharing mechanism to encourage additional fuel savings.

*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 which is being prepared by the Department of Energy and the Department of Interior. We currently expect that the report will be submitted to Congress by the end of this year. 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, including those 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 September 30, 2006, we had approximately $540 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 September 30, 2006, we have accrued approximately $362 million, which has not been reduced by $30 million for amounts to be paid directly under government sponsored programs. Our accrual includes approximately $351 million for expected remediation costs and associated onsite, offsite and groundwater technical studies and approximately $11 million for related environmental legal costs. Of the $362 million accrual, $66 million was reserved for facilities we currently operate and $296 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 $362 million to approximately $582 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 ($60 million). Second, where the most likely outcome cannot be estimated, a range of costs is established ($302 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 | September 30, 2006 Expected | High |
|---|---|---|
| | (In millions) | |
| Operating | $ 66 | $ 72 |
| Non-operating | 259 | 446 |
| Superfund | 37 | 64 |
| Total | $362 | $582 |

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

| | |
|---|---|
| Balance as of January 1, 2006 | $379 |
| Additions/adjustments for remediation activities | 33 |
| Payments for remediation activities | (50) |
| Balance as of September 30, 2006 | $362 |

For the remainder of 2006, we estimate that our total remediation expenditures will be approximately $20 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 $77 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 remediation activities at certain of its compressor stations associated with the presence of PCB and 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 September 30, 2006, TGP had pre-collected PCB costs of approximately $138 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 $127 million as of September 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 54 active sites under the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) or state equivalents. We have sought to resolve our liability as a PRP at these sites through indemnification by third-parties and settlements, which provide for payment of our allocable share of remediation costs. As of September 30, 2006, we have estimated our share of the remediation costs at these sites to be between $37 million and $64 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 in the form 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 September 30, 2006, we had recorded obligations of $69 million related to our guarantees and indemnification arrangements. These arrangements had a total stated value of approximately $330 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 9. Included in the above stated value of $330 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 $378 million associated with our estimated exposure under this matter as of September 30, 2006. For a further discussion of this matter, see *Retiree Medical Benefits Matters* above.

### 11. Retirement Benefits

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

| | Quarters Ended September 30, | | | | Nine Months Ended September 30, | | | |
|---|---|---|---|---|---|---|---|---|
| | Pension Benefits | | Other Postretirement Benefits | | Pension Benefits | | Other Postretirement Benefits | |
| | 2006 | 2005 | 2006 | 2005 | 2006 | 2005 | 2006 | 2005 |
| | (In millions) | | | | | | | |
| Service cost | $ 4 | $ 5 | $— | $— | $ 12 | $ 17 | $ — | $— |
| Interest cost | 29 | 29 | 7 | 7 | 87 | 87 | 21 | 22 |
| Expected return on plan assets | (44) | (42) | (4) | (3) | (132) | (126) | (12) | (9) |
| Amortization of net actuarial loss | 14 | 16 | — | — | 42 | 48 | — | — |
| Amortization of transition obligation | — | — | — | 2 | — | — | — | 6 |
| Amortization of prior service cost[(1)] | — | — | — | — | — | (2) | — | — |
| Net benefit cost | $ 3 | $ 8 | $ 3 | $ 6 | $ 9 | $ 24 | $ 9 | $19 |

(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 $54 million and $63 million of cash contributions to our Supplemental Benefits Plan and other postretirement plans during the nine months ended September 30, 2006 and 2005. We expect to contribute an additional $1 million to the Supplemental Benefits Plan and $11 million to our other postretirement plans for the remainder of 2006. Contributions to our other retirement benefit plans will be approximately $2 million for the remainder of 2006. As further described in Note 1, during the fourth quarter of 2006 we will adopt the recognition and disclosure provisions of SFAS No. 158.

## 12. 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 September 30, 2006 | $80 | $28 |
| Amount paid in October 2006 | $27 | $9 |
| Declared subsequent to September 30, 2006: | | |
| Date of declaration | October 26, 2006 | October 26, 2006 |
| Date payable | January 2, 2007 | January 2, 2007 |
| Payable to shareholders of record | December 1, 2006 | December 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.

## 13. 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 September 30, 2006, approximately 36 million shares remain available for grant under our current plans. In addition, we have approximately 23 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 forfeitures. 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 September 30, 2006, and approximately $0.01 per basic and diluted share for the nine months ended September 30, 2006. During the quarter and nine months ended September 30, 2006, we recognized $2 million and $8 million of additional pre-tax compensation expense, capitalized approximately $1 million of this expense as part of fixed assets and recorded $1 million and $3 million of income tax benefits. We expect to record incremental compensation expense of approximately $3 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 September 30, 2005 | Nine Months Ended September 30, 2005 |
|---|---|---|
| Net loss available to common stockholders, as reported | $ (321) | $ (461) |
| Add: Stock-based employee compensation expense included in reported net loss, net of taxes | 3 | 8 |
| Deduct: Total stock-based compensation expense, determined under fair-value based method for all awards, net of taxes | 4 | 14 |
| Net loss available to common stockholders, pro forma | $ (322) | $ (467) |
| Basic and Diluted loss per share: | | |
| As reported | $(0.50) | $(0.72) |
| Pro forma | $(0.50) | $(0.73) |

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 nine months ended September 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 | 2,311,708 | $12.30 | | |
| Exercised | (413,507) | $ 7.57 | | |
| Forfeited or canceled | (900,193) | $11.11 | | |
| Expired | (3,319,033) | $40.56 | | |
| Outstanding at September 30, 2006 | 25,762,460 | $35.83 | 4.96 | $41 |
| Vested at September 30, 2006 or expected to vest in the future | 25,426,715 | $36.17 | 4.91 | $40 |
| Exercisable at September 30, 2006 | 19,047,555 | $44.87 | 3.71 | $18 |

Total compensation cost related to non-vested option awards not yet recognized at September 30, 2006 was approximately $13 million, which is expected to be recognized over a weighted average period of 12 months. Options exercised during the nine months ended September 30, 2006 had a total intrinsic value of approximately $3 million, generated $3 million of cash proceeds and did not generate any significant associated income tax benefit. The total intrinsic value, cash received and income tax benefit generated from option exercises was not material during the nine months ended September 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 nine months ended September 30, 2006 and 2005, the weighted average grant date fair value per share of options granted was $4.98 and $3.87. Listed below is the weighted average of each assumption based on grants in each of the quarters and nine months ended September 30:

| | Quarters Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2006 | 2005 | 2006 | 2005 |
| Expected Term in Years | 6.0 | 4.8 | 6.0 | 4.8 |
| Expected Volatility | 37% | 39% | 38% | 42% |
| Expected Dividends | 1.2% | 1.4% | 1.3% | 1.5% |
| Risk-Free Interest Rate | 4.9% | 4.2% | 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 time-based restricted stock and performance-based restricted share awards. 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 nine months ended September 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 | 1,283,533 | $12.61 |
| Vested | (1,847,952) | $12.29 |
| Forfeited | (351,553) | $10.13 |
| Nonvested at September 30, 2006 | 3,000,058 | $10.77 |

The weighted average grant date fair value per share for restricted stock granted during the first nine months of 2006 and 2005 was $12.61 and $10.74. The total fair value of shares vested during the nine months ended September 30, 2006 and 2005 was $23 million and $13 million.

During the quarter and nine months ended September 30, 2006, we recognized approximately $2 million and $12 million of pre-tax compensation expense, capitalized approximately $1 million as part of fixed assets and recorded $1 million and $4 million of income tax benefits related to restricted stock arrangements. During the quarter and nine months ended September 30, 2005 we recognized approximately $4 million and $13 million of pretax compensation expense, capitalized approximately $1 million of this expense as part of fixed assets and recorded $2 million and $5 million of income tax benefits related to restricted stock arrangements. The total unrecognized compensation cost related to these arrangements at September 30, 2006 was approximately $16 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 SFAS No. 123(R).

*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).

## 14. Business Segment Information

As of September 30, 2006, our business consists of Pipelines, Exploration and Production, 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 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 September 30:

| | Quarters Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2006 | 2005 | 2006 | 2005 |
| | (In millions) | | | |
| Total EBIT | $ 359 | $ (92) | $1,734 | $ 809 |
| Interest and debt expense | (310) | (337) | (990) | (1,013) |
| Preferred interests of consolidated subsidiaries | — | — | — | (9) |
| Income taxes | 86 | 136 | (81) | 100 |
| Income (loss) from continuing operations | $ 135 | $(293) | $ 663 | $ (113) |

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

| Quarter Ended September 30, | Segments: Pipelines | Segments: Exploration and Production | Segments: Marketing and Trading | Segments: Power | Corporate[1] | Total |
|---|---|---|---|---|---|---|
| | | | (In millions) | | | |
| 2006 | | | | | | |
| Revenues from external customers | $686 | $186[2] | $ 162 | $ 1 | $ 26 | $1,061 |
| Intersegment revenues | 15 | 270[2] | (267) | 2 | (20) | — |
| Operation and maintenance | 230 | 109 | 6 | 14 | 7 | 366 |
| Depreciation, depletion and amortization | 114 | 163 | 1 | — | 4 | 282 |
| Loss on long-lived assets | 15 | — | — | — | — | 15 |
| Earnings from unconsolidated affiliates | 39 | 2 | — | 28 | — | 69 |
| EBIT | 305 | 141 | (108) | 38 | (17) | 359 |

| | 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 | $630 | $155[2] | $ (95) | $(12) | $ 38 | $ 15 | $731 |
| Intersegment revenues | 16 | 294[2] | (294) | 14 | 7 | (16) | 21[3] |
| Operation and maintenance | 218 | 94 | 14 | 19 | 29 | 80 | 454 |
| Depreciation, depletion and amortization | 108 | 153 | 1 | 1 | 1 | 6 | 270 |
| Loss on long-lived assets | — | — | — | — | 3 | — | 3 |
| Earnings (losses) from unconsolidated affiliates | 51 | — | — | (42) | 4 | — | 13 |
| EBIT | 272 | 169 | (398) | (46) | (22) | (67) | (92) |

(1) Includes eliminations of intercompany transactions. Our intersegment revenues, along with our intersegment operating expenses, were incurred in the normal course of business between our operating segments. For the quarters ended September 30, 2006 and 2005, we recorded an intersegment revenue elimination of $18 million and $13 million and operation and maintenance expense eliminations of $12 million and $1 million, which are 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.

| Nine Months Ended September 30, | Segments: Pipelines | Segments: Exploration and Production | Segments: Marketing and Trading | Segments: Power | Corporate[(1)] | Total |
|---|---|---|---|---|---|---|
| | | | (In millions) | | | |
| 2006 | | | | | | |
| Revenues from external customers | $2,197 | $501[(2)] | $1,015 | $ 4 | $ 89 | $3,806 |
| Intersegment revenues | 46 | 883[(2)] | (897) | 2 | (34) | — |
| Operation and maintenance | 668 | 295 | 18 | 44 | 60 | 1,085 |
| Depreciation, depletion and amortization | 344 | 465 | 3 | 1 | 19 | 832 |
| Loss on long-lived assets | 15 | — | — | — | — | 15 |
| Earnings (losses) from unconsolidated affiliates | 114 | 10 | — | 43 | (1) | 166 |
| EBIT | 1,118 | 503 | 113 | 51 | (51) | 1,734 |

| | 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 | $2,012 | $457[(2)] | $ 238 | $ 70 | $103 | $ 66 | $2,946 |
| Intersegment revenues | 55 | 883[(2)] | (823) | 9 | 18 | (79) | 63[(3)] |
| Operation and maintenance | 635 | 277 | 33 | 64 | 32 | 209 | 1,250 |
| Depreciation, depletion and amortization | 327 | 456 | 3 | 2 | 3 | 32 | 823 |
| (Gain) loss on long-lived assets | (10) | — | — | 14 | 10 | (4) | 10 |
| Earnings (losses) from unconsolidated affiliates | 127 | — | — | (129) | 186 | — | 184 |
| EBIT | 993 | 528 | (613) | (87) | 157 | (169) | 809 |

(1) Includes eliminations of intercompany transactions. Our intersegment revenues, along with our intersegment operating expenses, were incurred in the normal course of business between our operating segments. For the nine months ended September 30, 2006 and 2005, we recorded an intersegment revenue elimination of $32 million and $76 million and operation and maintenance expense eliminations of $13 million and $1 million, which are 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:

| | September 30, 2006 | December 31, 2005 |
|---|---|---|
| | (In millions) | |
| Pipelines | $16,899 | $16,447 |
| Exploration and Production | 6,188 | 5,570 |
| Marketing and Trading | 1,027 | 3,819 |
| Power | 745 | 1,176 |
| Field Services | — | 99 |
| Total segment assets | 24,859 | 27,111 |
| Corporate | 2,506 | 4,144 |
| Discontinued operations | 34 | 583 |
| Total consolidated assets | $27,399 | $31,838 |

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

*Investments in Unconsolidated Affiliates*

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 | | | |
|---|---|---|---|---|---|
| | | Quarters Ended September 30, | | Nine Months Ended September 30, | |
| | September 30, 2006 | 2006 | 2005 | 2006 | 2005 |
| | (Percent) | (In millions) | | | |
| Domestic: | | | | | |
| Citrus Corporation | 50 | $19 | $ 19 | $ 48 | $ 52 |
| Great Lakes Gas Transmission Company | 50 | 14 | 15 | 44 | 46 |
| Four Star Oil & Gas Company[(1)] | 43 | 2 | — | 10 | — |
| Midland Cogeneration Venture | — | 13 | (159) | 13 | (162) |
| Enterprise Products Partners, L.P.[(2)] | — | — | — | — | 183 |
| Other Domestic Investments | various | (2) | 16 | 3 | 22 |
| Total domestic | | 46 | (109) | 118 | 141 |
| Foreign: | | | | | |
| Asia Investments[(3)] | various | 2 | 110 | (2) | 64 |
| Central American Investments[(4)] | various | — | — | (1) | (49) |
| Other Foreign Investments | various | 21 | 12 | 51 | 28 |
| Total foreign | | 23 | 122 | 48 | 43 |
| Total earnings from unconsolidated affiliates | | $69 | $ 13 | $166 | $ 184 |

(1) We acquired our interest in Four Star in connection with our acquisition of Medicine Bow in the third quarter of 2005. Amortization of our purchase cost in excess of the underlying net assets of Four Star was $13 million and $40 million during the quarter and nine months ended September 30, 2006 and $5 million during each of the same periods in 2005.

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

(3) As of September 30, 2006, consists of our investments in four power plants, one of which was sold in October 2006.

(4) As of September 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 from unconsolidated affiliates. During the periods ended September 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 realized gains (losses) and impairment charges consisted of the following for the periods ended September 30:

| | Quarters Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| Investment or Group | 2006 | 2005 | 2006 | 2005 |
| | (In millions) | | | |
| Asian power investments | $ 1 | $ — | $ (6) | $ (71) |
| Central American power investments | — | — | (2) | (57) |
| Enterprise | — | — | — | 183 |
| Midland Cogeneration Venture | 13 | (159) | 13 | (162) |
| KIECO | — | 109 | — | 109 |
| Other foreign investments | — | — | 2 | (17) |
| Other | — | 11 | — | 8 |
| | $14 | $ (39) | $ 7 | $ (7) |

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

| | Quarters Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2006 | 2005 | 2006 | 2005 |
| | (In millions) | | | |
| Operating results data | | | | |
| Revenues | $308 | $ 453 | $993 | $1,205 |
| Operating expenses | 153 | 738 | 662 | 1,156 |
| Income from continuing operations | 101 | (352) | 152 | (143) |
| Net income[1] | 101 | (352) | 152 | (143) |

[1] Includes net income of $2 million and $8 million for the quarters ended September 30, 2006 and 2005, and $11 million and $22 million for the nine months ended September 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 $76 million and $50 million for the quarters ended September 30, 2006 and 2005 and $188 million and $197 million for the nine months ended September 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 September 30:

| | Quarters Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2006 | 2005 | 2006 | 2005 |
| | (In millions) | | | |
| Operating revenue | $ 2 | $26 | $63 | $118 |
| Cost of sales | 3 | 4 | 7 | 10 |
| Reimbursement for operating expenses | — | 1 | 2 | 2 |
| Other income | 13 | 13 | 39 | 42 |

*Accounts Receivable Sales Program.* During the third quarter of 2006, we entered into agreements to sell certain accounts receivable to qualifying special purpose entities (QSPEs) under SFAS No. 140, *Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities*. As of September 30, 2006, we sold approximately $98 million of receivables, received cash of approximately $58 million, received subordinated beneficial interests of approximately $39 million, and recognized a loss of approximately $1 million. In conjunction with the sale, the QSPEs also issued senior beneficial interests on the receivables sold to a third party financial institution, which totaled $59 million on the closing date. Prior to its redemption, we reflect the subordinated beneficial interest in receivables sold as accounts receivable from affiliates in our balance sheet. We reflect accounts receivable sold under this program and the related redemption of the subordinated beneficial interests as operating cash flows in our statement of cash flows. Under the agreements, we earn a fee for servicing the accounts receivable and performing all administrative duties for the QSPEs which is reflected as a reduction of operation and maintenance expense in our income statement. The fair value of these servicing and administrative agreements as well as the fees earned were not material to our financial statements for the period ended September 30, 2006.

*Matters that Could Impact Our Investments*

*Domestic Power.* In August 2006, we sold our interest in the MCV power plant. We continue to supply gas to MCV under natural gas supply contracts and in the third quarter of 2006 recorded a loss of approximately $133 million on these contracts as they were no longer with an affiliate. Prior to the sale, we had not recognized the cumulative mark-to-market losses on these contracts to the extent of our ownership interest due to their affiliated nature. To secure our remaining obligations under these contracts, we have also issued letters of credit to MCV for approximately $256 million as of September 30, 2006.

During the fourth quarter of 2006, we transferred our ownership interest in our Berkshire power facility to our partner in the facility and terminated the fuel management agreement and all other obligations related to the project. These transactions did not result in a significant gain or loss.

*Investments in Asia and Central America.* As of September 30, 2006, we have net exposure (including guarantees and letters of credit) of approximately $170 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. In October 2006, we sold our investment in the Sengkang project in Indonesia, which reduced our exposure in this area by approximately $60 million.

*Investment in Brazil.* We own an investment in the Porto Velho power plant in Brazil in which our exposure (including guarantees and letters of credit) was approximately $330 million at September 30, 2006. The state-owned facility that purchases power generated by the facility has approached us with the opportunity to potentially sell them our interest in this power plant. Although we currently have no indications of an impairment of our investment, as we evaluate this potential opportunity, we could be required to record a loss based on the potential value we may receive.

*Investment in Bolivia.* We own an 8 percent interest in the Bolivia to Brazil pipeline. As of September 30, 2006, our total exposure, including guarantees, in this pipeline project was approximately $115 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 September 30, 2006, our total exposure in this pipeline project was approximately $25 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 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. The trial related to this lawsuit is scheduled to commence later this year. 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

*Financial Update.* During 2006, our financial performance has been relatively stable. Our pipeline business has experienced solid growth and continues to provide a strong base of earnings and cash flow. Our exploration and production business has experienced continued success in its drilling programs, has brought new production on line and has recovered much of the volumes lost in the 2005 hurricanes, all resulting in higher production levels during each quarter of this year. Additionally, recent declines in commodity prices have negatively impacted our exploration and production segment's results, although this was somewhat mitigated through price risk management activities in this segment and in our marketing and trading segment. Our segment discussions that follow provide further analysis of our results for the quarter and nine months ended September 30, 2006.

*Credit Metrics Update.* In 2006, our credit metrics have strengthened as we continue to resolve our legacy issues. To date in 2006, we have paid down approximately $3 billion of debt. Additionally, we have generated proceeds of approximately $0.9 billion from asset sales, issued approximately $0.5 billion of common stock, restructured our revolving credit facilities with improved terms, and sold or entered into contracts to eliminate the price risk on a substantial portion of our legacy natural gas book. During 2006, both Moody's Investor's Service and Standard and Poor's have upgraded our senior unsecured credit rating to B2 and B and we are on positive outlook by these agencies. Our liquidity and capital resources discussions that follow provide further discussion of these events.

*What to Expect Going Forward.* For the fourth quarter of 2006 and into 2007, we expect the current operating trends to continue. In our pipeline business, we continue to lay the foundation for further future growth by building an inventory of expansion projects and developing significant infrastructure opportunities while at the same time maintaining our existing asset base. We anticipate that our pipeline operations will continue to provide strong operating results based on the current levels of contracted capacity, continued success in recontracting, expansion plans in market and supply areas and the status of rate and regulatory actions.

In our exploration and production business, we will continue to create value through a disciplined and balanced capital investment program, actively manage the increasing cost of production services, and seek efficiency improvements. In our drilling programs, we will focus on delivering reserves and volumes at reasonable finding and operating costs. Our future financial results will be dependent on the continued successful execution of these drilling programs as well as commodity prices. However, for 2006, lower than planned volumes due to delays in bringing production online, delays in recovering lost hurricane volumes and higher than planned maintenance in certain onshore fields will impact our ability to attain the operational and financial targets we previously established for this business.

Finally, we continue to work to achieve our net debt target (debt, less cash) of approximately $14 billion by the end of 2006. Our ability to achieve this target will be based on continuing to generate strong cash flow from our businesses, completing the sale of our remaining power assets and may be influenced by the resolution of legacy issues.

### Segment Results

Below are our results of operations (as measured by EBIT) by segment. Our business segments consist of our Pipelines, Exploration and Production, 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 September 30:

| | Quarters Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2006 | 2005 | 2006 | 2005 |
| | (In millions) | | | |
| Pipelines | $ 305 | $ 272 | $1,118 | $ 993 |
| Exploration and Production | 141 | 169 | 503 | 528 |
| Marketing and Trading | (108) | (398) | 113 | (613) |
| Power | 38 | (46) | 51 | (87) |
| Field Services | — | (22) | — | 157 |
| Segment EBIT | 376 | (25) | 1,785 | 978 |
| Corporate | (17) | (67) | (51) | (169) |
| Consolidated EBIT from continuing operations | 359 | (92) | 1,734 | 809 |
| Interest and debt expense | (310) | (337) | (990) | (1,013) |
| Preferred interests of consolidated subsidiaries | — | — | — | (9) |
| Income taxes | 86 | 136 | (81) | 100 |
| Income from continuing operations | 135 | (293) | 663 | (113) |
| Discontinued operations, net of income taxes | — | (19) | (22) | (331) |
| Net income (loss) | $ 135 | $(312) | $ 641 | $ (444) |

## 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 September 30:

| | Quarters Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2006 | 2005 | 2006 | 2005 |
| | (In millions) | | | |
| Operating revenues | $ 701 | $ 646 | $ 2,243 | $ 2,067 |
| Operating expenses | (442) | (439) | (1,262) | (1,236) |
| Operating income | 259 | 207 | 981 | 831 |
| Other income | 46 | 65 | 137 | 162 |
| EBIT | $ 305 | $ 272 | $ 1,118 | $ 993 |
| Throughput volumes (BBtu/d) | 22,375 | 20,900 | 21,907 | 21,260 |

| | Quarter Ended September 30, | | | | Nine Months Ended September 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 | $ 37 | $ — | $ — | $ 37 | $140 | $ — | $ — | $140 |
| Gas not used in operations, revaluations, processing revenues and other natural gas sales | (15) | 27 | — | 12 | 13 | 36 | — | 49 |
| Pipeline expansions | 19 | (1) | (5) | 13 | 57 | (6) | (8) | 43 |
| Contract restructurings/settlements | — | (2) | — | (2) | (43) | (2) | (1) | (46) |
| Impact of hurricanes Katrina and Rita | — | (9) | — | (9) | — | (28) | — | (28) |
| Impairment of pipeline development projects | — | (16) | — | (16) | — | (18) | — | (18) |
| Higher depreciation expense | — | (5) | — | (5) | — | (12) | — | (12) |
| Higher pipeline integrity expense | — | (7) | — | (7) | — | (14) | — | (14) |
| Enron bankruptcy settlement | 14 | 4 | — | 18 | 14 | 4 | — | 18 |
| Sale of interest in gathering system | — | — | (11) | (11) | — | — | (11) | (11) |
| Other[(1)] | — | 6 | (3) | 3 | (5) | 14 | (5) | 4 |
| Total impact on EBIT | $ 55 | $ (3) | $(19) | $ 33 | $176 | $(26) | $(25) | $125 |

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

*Higher Reservation and Other Services Revenues.* During the quarter and nine months ended September 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, sales of additional firm capacity and higher realized rates 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 as a result of favorable market conditions.

*Gas Not Used in Operations, Revaluations, Processing Revenues and Other Natural Gas Sales.* During the nine months ended September 30, 2006, higher realized prices on sales of gas not used in operations resulted in favorable impacts to our operating revenues, partially offset by lower sales volumes of natural gas during the quarter and nine months ended September 30, 2006 compared to the same periods in 2005. We also experienced favorable impacts to our operating expenses due to decreases in the index prices used to value the net imbalance position on several of our pipeline systems. 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.* Below is a discussion of our FERC approved expansion projects placed in service and their impact on our results as well as other expansion projects not yet completed.

- *Expansion Projects in Service.* 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 $6 million and $21 million and overall EBIT increased by $5 million and $20 million during the quarter and nine months ended September 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 $7 million for the remainder of 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, $11 million in 2007 and approximately $20 million annually thereafter.

- *Expansion Projects Not Yet Completed.* 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, which is currently under construction, will consist of three phases with a total capital cost of approximately $321 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.

  In July 2006, the FERC granted certificate authorization for TGP's proposed Essex Middlesex Project. This project will add 80 MMcf/d of natural gas capacity to the New England area and serve various points on TGP's New England system. Estimated costs to complete the project are approximately $38 million and the anticipated in service date is September 2007. The expansion is estimated to increase our revenues by $1 million in 2007 and $7 million annually thereafter.

*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.

*Hurricanes Katrina and Rita.* During the quarter and nine months ended September 30, 2006 we recorded higher operation and maintenance expenses as a result of unreimbursed amounts expended to repair damage caused by Hurricanes Katrina and Rita. We 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.

*Impairment of Pipeline Development Projects.* During the third quarter of 2006, we discontinued our Continental Connector Pipeline project and our Seafarer Project due to changing market conditions.

*Higher Depreciation Expense.* Depreciation expense was higher for the quarter and nine months ended September 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 adopted an accounting release issued by the FERC that requires us to expense 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. We anticipate we will expense additional costs of approximately $7 million for the remainder of the year.

*Enron Bankruptcy Settlement.* During the third quarter of 2006, we recorded income of approximately $18 million, net of amounts potentially owed to certain customers, associated with the receipt of settlement proceeds related to the Enron bankruptcy. We may receive additional amounts in the future as settlement proceeds are released by the bankruptcy court.

*Other Regulatory Matter.* In August 2006, the FERC approved a settlement reached with CIG's customers to be effective October 1, 2006. The settlement establishes system-wide base rates through at least September 2010, but no later than September 2011, and establishes a sharing mechanism to encourage additional fuel savings. We anticipate an increase in revenues of approximately $6 million annually as a result of the settlement.

**Exploration and Production Segment**

*Overview*

Our Exploration and Production segment conducts our natural gas and oil exploration and production activities. We manage this business with the goal of creating 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 competitive investment returns.

Our operating results in this segment are driven by the ability to locate and develop economic natural gas and oil reserves and extract those reserves with the lowest possible production and administrative costs. Changes in commodity prices can substantially impact our results; however, we have entered into derivative contracts on a portion of our natural gas and oil production to reduce the financial impact of downward commodity price movements. In addition, industry-wide increases in drilling and oilfield service costs, although actively managed by us, will continue to impact our results.

*Significant Developments Since December 31, 2005*

- *Realized commodity prices.* During the first half of 2006, we benefited from a strong commodity pricing environment. However, during the third quarter natural gas prices decreased from those experienced during the first half of the year.

- *Drilling Results / Average Daily Production.* Our average daily production through September 30, 2006, was approximately 719 MMcfe/d (excluding 67 MMcfe/d from our equity investment in Four Star). Our production levels have grown in each of the first three quarters of this year, as well as from the third quarter of 2005. However, our average daily production was lower than originally expected primarily due to events in our Gulf of Mexico and Onshore regions as further discussed below. Our drilling and production results by region were as follows during the first nine months of 2006:

  *Onshore.* Our drilling program in this region has provided production growth and achieved a 100 percent success rate on 328 gross wells drilled. While our drilling program has been successful, the impact of higher maintenance activity and delivery delays for two rigs contracted in East Texas have reduced our expected year-to-date production.

  *Gulf of Mexico and south Louisiana.* Since the end of 2005, production in this region has increased as we continued to recover from the 2005 hurricanes and tie-in new producing wells. In our drilling program we have experienced a 92 percent success rate on 13 gross wells drilled. We have placed nine new wells in production, including five wells in south Louisiana, and four wells in the Gulf of Mexico. We expect an additional four wells to come on production in 2007, one of which was drilled in October 2006. While our overall drilling program has been successful, slower than expected recovery of production shut-in by hurricane damage and construction delays on certain new wells have negatively impacted our 2006 production. As of September 30, 2006, approximately 6 MMcfe/d of hurricane related production remains shut-in.

*Texas Gulf Coast.* Our capital program in this region has stabilized production volumes over the last twelve months and we have experienced a 94 percent success rate on 33 gross wells drilled. Detailed geoscience and engineering efforts continue to pay off on our Jeffress (Vicksburg) properties where we have grown gross-operated production by 50 percent since the beginning of 2006, and have added to the low-risk drilling inventory in this mature field. Even though we expect to spend a higher portion of our capital on exploration in the fourth quarter, continued focus on execution of the development programs keep us on track to achieve our 2006 production targets for this region.

*International.* In Brazil, since the end of 2005, average daily production volumes have averaged 26 MMcfe/d which reflects a contractual reduction in 2006 of our ownership interest in the Pescada-Arabaiana Field from 79 percent to 35 percent. In the Pinauana Field, we filed a plan of development, signed a rig contract and are preparing to drill the first exploratory well in the fourth quarter of 2006 upon receipt of licensing approvals. Additionally, in the ES-5 Block in the Espirito Santo Basin, we continue to discuss a possible fourth quarter 2006 exploration well with Petrobras.

In Egypt, we were the winning bidder of the South Mariut Block for $3 million in the second quarter of 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. We expect to receive formal governmental approvals and sign the concession agreement during the first quarter of 2007.

- *Cash Operating Costs.* In the third quarter of 2006, cash operating costs increased to $1.95/MMcfe from $1.86/MMcfe in the second quarter of 2006. Our operating cost increases were primarily a result of inflation in the cost of fuel, power, and other services, increases in subsurface maintenance in certain Onshore fields and unrecoverable hurricane repair costs, among other items. We do not expect a significant amount of unrecoverable costs related to the hurricanes in the fourth quarter.

*Outlook for 2006*

For 2006, we anticipate the following:

- Average daily production volumes for the year of approximately 725 MMcfe/d to 735 MMcfe/d, which excludes approximately 65 MMcfe/d from our equity interest in Four Star. Average daily production volumes for the year are lower than originally anticipated due to slower than expected recovery of lost hurricane volumes, production delays in the Gulf of Mexico and tightness in the supply of rigs and other services onshore;

- Capital expenditures for the year between $1.1 billion and $1.2 billion including accrued capital expenditures;

- Average cash operating costs which include production costs, general and administrative expenses and other expenses of approximately $1.82/Mcfe to $1.87/Mcfe for the year; and

- A unit of production depletion rate of between $2.40/Mcfe and $2.50/Mcfe in the fourth quarter of 2006 compared with $2.27/Mcfe in the third quarter of 2006 due to higher finding and development costs and the effects of low quarter end prices on reserves.

*Price Risk Management Activities*

We enter into derivative contracts on our natural gas and oil production to stabilize cash flows, reduce the risk and financial impact of downward commodity price movements on commodity sales and to protect the economic assumptions associated with our capital investment programs. During 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

September 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 hedged production:

| | Fixed Price Swaps(1) | | Floors(1) | | Ceilings(1) | | Basis Swaps(1)(3) |
|---|---|---|---|---|---|---|---|
| | Volumes | Price | Volumes | Price | Volumes | Price | Volumes |
| *Natural Gas(2)* | | | | | | | |
| 2006 | 21 | $ 6.28 | — | — | — | — | 23 |
| 2007 | 5 | $ 3.56 | 130 | $8.00 | 130 | $16.02 | 110 |
| 2008 | 5 | $ 3.42 | — | — | — | — | — |
| 2009-2012 | 16 | $ 3.74 | — | — | — | — | — |
| *Oil* | | | | | | | |
| 2006 | 96 | $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 into, or the price on the day it was designated as a hedge. In 2006, the average cash price under our fixed price natural gas swaps 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. 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 September 30:

| | Quarters Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2006 | 2005 | 2006 | 2005 |
| | (In millions) | | | |
| Operating Revenues: | | | | |
| Natural gas | $ 357 | $ 354 | $1,049 | $1,061 |
| Oil, condensate and NGL | 119 | 105 | 327 | 286 |
| Other | (20) | (10) | 8 | (7) |
| Total other operating revenues | 456 | 449 | 1,384 | 1,340 |
| Operating Expenses: | | | | |
| Depreciation, depletion and amortization | (163) | (153) | (465) | (456) |
| Production costs(1) | (92) | (72) | (235) | (186) |
| Cost of products and services(2) | (23) | (11) | (67) | (36) |
| General and administrative expenses | (38) | (45) | (121) | (129) |
| Other | (2) | (1) | (6) | (11) |
| Total operating expenses | (318) | (282) | (894) | (818) |
| Operating income | 138 | 167 | 490 | 522 |
| Other income(3) | 3 | 2 | 13 | 6 |
| EBIT | $ 141 | $ 169 | $ 503 | $ 528 |

| | Quarters Ended September 30, | | | Nine Months Ended September 30, | | |
|---|---|---|---|---|---|---|
| | 2006 | 2005 | Percent Variance | 2006 | 2005 | Percent Variance |
| *Consolidated volumes, prices and costs per unit:* | | | | | | |
| Natural gas | | | | | | |
| Volumes (MMcf) | 56,736 | 55,280 | 3% | 162,403 | 169,228 | (4)% |
| Average realized prices including hedges ($/Mcf)[4] | $ 6.30 | $ 6.40 | (2)% | $ 6.46 | $ 6.27 | 3% |
| Average realized prices excluding hedges ($/Mcf)[4] | $ 6.31 | $ 7.74 | (18)% | $ 6.79 | $ 6.59 | 3% |
| Average transportation costs ($/Mcf) | $ 0.23 | $ 0.18 | 28% | $ 0.23 | $ 0.18 | 28% |
| Oil, condensate and NGL | | | | | | |
| Volumes (MBbls) | 1,959 | 2,068 | (5)% | 5,662 | 6,464 | (12)% |
| Average realized prices including hedges ($/Bbl)[4] | $ 60.81 | $ 50.77 | 20% | $ 57.81 | $ 44.23 | 31% |
| Average realized prices excluding hedges ($/Bbl)[4] | $ 60.81 | $ 51.88 | 17% | $ 58.22 | $ 44.94 | 30% |
| Average transportation costs ($/Bbl) | $ 0.71 | $ 0.60 | 18% | $ 0.91 | $ 0.64 | 42% |
| Total equivalent volumes | | | | | | |
| MMcfe | 68,490 | 67,684 | 1% | 196,376 | 208,011 | (6)% |
| MMcfe/d | 744 | 736 | 1% | 719 | 762 | (6)% |
| Production Costs ($/Mcfe) | | | | | | |
| Average lease operating cost | $ 1.03 | $ 0.74 | 39% | $ 0.89 | $ 0.71 | 25% |
| Average production taxes | 0.32 | 0.32 | —% | 0.31 | 0.19 | 63% |
| Total production cost[1] | $ 1.35 | $ 1.06 | 27% | $ 1.20 | $ 0.90 | 33% |
| Average general and administrative cost ($/Mcfe) | $ 0.57 | $ 0.65 | (12)% | $ 0.62 | $ 0.62 | —% |
| Unit of production depletion cost ($/Mcfe) | $ 2.27 | $ 2.11 | 8% | $ 2.24 | $ 2.05 | 9% |
| *Unconsolidated affiliate volumes (Four Star)* | | | | | | |
| Natural gas (MMcf) | 4,379 | 1,605 | | 13,342 | 1,605 | |
| Oil, condensate and NGL (MBbls) | 278 | 92 | | 847 | 92 | |
| Total equivalent volumes | | | | | | |
| MMcfe | 6,049 | 2,156 | | 18,424 | 2,156 | |
| MMcfe/d | 66 | 23 | | 67 | 8 | |

(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 for our investment in Four Star acquired in connection with our acquisition of Medicine Bow in the third quarter 2005.

(4) Prices are stated before transportation costs.

*Operating Results and Variance Analysis (cont'd)*

| | Quarter Ended September 30, 2006 | | | | Nine Months Ended September 30, 2006 | | | |
|---|---|---|---|---|---|---|---|---|
| | Variance | | | | Variance | | | |
| | Operating Revenue | Operating Expense | Other | EBIT | Operating Revenue | Operating Expense | Other | EBIT |
| | Favorable/(Unfavorable) (In millions) | | | | | | | |
| *Natural Gas Revenue* | | | | | | | | |
| (Lower) higher realized prices in 2006 | $(81) | $ — | $— | $(81) | $ 32 | $ — | $— | $ 32 |
| Impact of hedges | 73 | — | — | 73 | 1 | — | — | 1 |
| Higher (lower) volumes in 2006 | 11 | — | — | 11 | (45) | — | — | (45) |
| *Oil, Condensate and NGL Revenue* | | | | | | | | |
| Higher realized prices in 2006 | 19 | — | — | 19 | 75 | — | — | 75 |
| Impact of hedges | 2 | — | — | 2 | 2 | — | — | 2 |
| Lower volumes in 2006 | (7) | — | — | (7) | (36) | — | — | (36) |
| *Depreciation, Depletion and Amortization Expense* | | | | | | | | |
| Higher depletion rate in 2006 | — | (13) | — | (13) | — | (37) | — | (37) |
| Lower production volumes in 2006 | — | — | — | — | — | 25 | — | 25 |
| *Production Costs* | | | | | | | | |
| Higher lease operating costs in 2006 | — | (21) | — | (21) | — | (28) | — | (28) |
| Lower (higher) production taxes in 2006 | — | 1 | — | 1 | — | (21) | — | (21) |
| *General and Administrative Expenses* | — | 7 | — | 7 | — | 8 | — | 8 |
| *Other* | | | | | | | | |
| Change in fair value of oil and basis swaps | (32) | — | — | (32) | (30) | — | — | (30) |
| Earnings from investment in Four Star | — | — | 2 | 2 | — | — | 10 | 10 |
| Processing plants | 11 | (8) | — | 3 | 34 | (24) | — | 10 |
| Other | 11 | (2) | (1) | 8 | 11 | 1 | (3) | 9 |
| *Total Variances* | $ 7 | $(36) | $ 1 | $(28) | $ 44 | $(76) | $ 7 | $(25) |

*Operating revenues.* During the first half of 2006, we benefited from a strong commodity price environment for natural gas and oil, condensate and NGL; however, realized natural gas prices, excluding the impact of hedges, experienced a decline in the third quarter of 2006. Offsetting the impact of the natural gas price declines were lower hedging program losses for the quarter and nine months ended September 30, 2006. We recorded hedge losses of $1 million and $56 million during the quarter and nine months ended September 30, 2006, compared to losses of $76 million and $59 million for the same periods in 2005. Realized oil, condensate, and NGL prices increased in 2006 when compared with the same periods in 2005.

Our production volumes have benefited from our acquisitions in 2005. However, overall production volumes have 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 volumes in Brazil decreased due to the contractual reduction of our ownership interest in the Pescada-Arabaiana Field in 2006.

*Depreciation, depletion and amortization expense.* During 2006, we experienced higher depletion rates as compared to 2005 as a result of higher finding and development costs and the cost of acquired reserves. However, lower production volumes in 2006 partially offset the impact of these higher depletion rates.

*Production costs.* In 2006, our lease operating costs increased as compared to 2005 in our Onshore region primarily due to our acquisition of Medicine Bow and in the Gulf of Mexico region due to hurricane repairs not recoverable through insurance. Additionally, production taxes increased as a result of lower tax credits in Texas taken in 2006 compared to 2005, and higher ad valorem taxes in 2006 due to the Medicine Bow acquisition.

*General and administrative expenses.* Our general and administrative expenses decreased during 2006 as compared to the same periods in 2005 as lower labor related costs and corporate overhead allocations were partially offset by higher environmental costs at our processing facilities and higher legal costs.

*Other.* During the quarter and nine months ended September 30, 2006, the fair value of our basis swaps decreased by approximately $45 million and $40 million, due primarily to changes in basis differentials in south Texas and the Texas Panhandle. In 2006, our EBIT was also impacted by earnings from Four Star, which was acquired in August 2005, operations at our processing plants and insurance recoveries resulting from Hurricane Ivan, among other items.

**Marketing and Trading Segment**

*Overview.* 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. For a further discussion of our contracts in this segment, see our Current Report on Form 8-K dated May 12, 2006. During 2006 we have entered into transactions to either sell or eliminate the price risk associated with a number of our legacy contracts including:

- *Legacy natural gas derivative contracts.* In September 2006, we sold or entered into offsetting derivative transactions to eliminate the price risk associated with a substantial portion of our remaining legacy natural gas derivatives. These transactions are expected to substantially reduce our future earnings exposure to changes in natural gas prices on our legacy natural gas contracts. We continue to evaluate potential opportunities to assign or otherwise divest of the remainder of our legacy natural gas positions, which could impact our future cash flows and financial results.

- *Natural gas transportation related contracts.* In the third quarter of 2006 we entered into agreements to release a portion of the capacity from August 2006 through April 2009 that we hold on a pipeline serving California. In addition, in October 2006, we assigned three transportation contracts with our affiliate, TGP to a third party. We continue to evaluate potential opportunities to assign or otherwise divest of other transportation-related contracts, which could impact our future cash flows and financial results.

- *Option contracts and basis swaps.* In the second quarter of 2006, we entered into contracts to effectively eliminate the price risk on certain existing option contracts entered into related to our 2007 natural gas production. These transactions substantially reduced any significant future earnings volatility related to these derivative contracts. In conjunction with these transactions, our Exploration and Production segment entered into new option contracts.

*Operating Results.* Our operating results for the quarter and nine month periods ended September 30, 2006 were primarily impacted by mark-to-market income on our production related natural gas and oil derivative contracts as commodity prices declined during 2006. Additionally, our results were impacted by a loss of approximately $133 million on our MCV natural gas supply agreements upon the Power segment's sale of its interest in that facility in August 2006. 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 September 30:

| | Quarters Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2006 | 2005 | 2006 | 2005 |
| | (In millions) | | | |
| *Overall EBIT:* | | | | |
| Gross margin[1] | $(105) | $(389) | $ 118 | $(585) |
| Operating expenses | (8) | (15) | (23) | (37) |
| Operating income (loss) | (113) | (404) | 95 | (622) |
| Other income, net[2] | 5 | 6 | 18 | 9 |
| EBIT | $(108) | $(398) | $ 113 | $(613) |
| *Gross Margin by Significant Contract Type:* | | | | |
| *Production-Related Natural Gas and Oil Derivative Contracts:* | | | | |
| Changes in fair value of swaps and options | $ 67 | $(390) | $ 256 | $(508) |
| *Contracts Related to Legacy Trading Operations:* | | | | |
| *Natural gas contracts:* | | | | |
| Transportation-related contracts: | | | | |
| Demand charges | (28) | (39) | (97) | (118) |
| Settlements | 15 | 36 | 52 | 84 |
| Changes in fair value of other natural gas derivative contracts[3] | (186) | (67) | (157) | 52 |
| *Power contracts:* | | | | |
| Change in fair value of power derivatives, excluding Cordova | 27 | 20 | 64 | (52) |
| Changes in fair value of Cordova tolling agreement[4] | — | 45 | — | (66) |
| Other[5] | — | 6 | — | 23 |
| Total gross margin | $(105) | $(389) | $ 118 | $(585) |

(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) Amounts for 2006 include a loss on natural gas supply agreements with MCV.

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

(5) 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 and are in addition to contracts entered into by 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. In 2006, we entered into positions to offset certain historical options which reduced the impact of commodity price changes on our production related natural gas and oil derivative contracts. Decreases in commodity prices favorably impacted the value of our contracts and our EBIT during 2006, whereas increases in commodity prices negatively impacted the value of our contracts and our EBIT during 2005. For the nine months ended September 30, 2006, we received approximately $22 million related to contracts that settled during the period.

*Contracts Related to Legacy Trading Operations*

*Natural gas transportation-related contracts.* Our ability to use the contracted capacity under our transportation-related contracts is impacted by price differentials between the receipt and delivery points 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 September 30:

| | Quarters Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2006 | 2005 | 2006 | 2005 |
| *Alliance:* | | | | |
| Demand charges | $16 | $ 16 | $48 | $48 |
| Recovery | 72% | 100% | 53% | 78% |
| *Enterprise Texas:* | | | | |
| Demand charges | $ 2 | $ 7 | $11 | $21 |
| Recovery | — | 33% | 34% | 42% |
| *Other:* | | | | |
| Demand charges | $10 | $ 16 | $38 | $49 |
| Recovery | 34% | 100% | 60% | 82% |

*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 and because natural gas prices decreased, the fair value of these contracts decreased during the quarters ended September 30, 2006 and 2005 and the nine months ended September 30, 2006. However, natural gas prices increased during the nine months ended September 30, 2005, resulting in an increase in the fair value of these contracts. Our EBIT for the nine months ended September 30, 2006 was also favorably impacted by a $49 million gain associated with the assignment of contracts to supply natural gas to certain municipalities in Florida.

In August 2006, our Power segment sold its interest in the MCV power plant. We continue to supply gas to MCV under natural gas supply contracts and in the third quarter of 2006 recorded a mark-to-market loss of approximately $133 million on these contracts. Prior to the sale, we had not recognized the cumulative mark-to-market losses on these contracts to the extent of our ownership interest due to their affiliated nature.

*Power Contracts.* Through 2005, we divested or entered into transactions to divest of a substantial portion of our power contracts, including our Cordova tolling agreement and substantially all of the contracts in our power portfolio, including those 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 on these contracts. Our remaining exposure in our power portfolio is primarily related to various contracts in the Pennsylvania-New Jersey-Maryland (PJM) region that swap locational differences in power prices between several power plants in the PJM eastern region with the PJM west hub as well as certain basis and installed capacity positions with Morgan Stanley in the PJM power pool that we entered into in December 2005. Prior to entering into those transactions in 2005, our results were also impacted by certain power supply contracts and related power purchase contracts used to manage the risk on those power supply obligations. The fair value of our power contracts, excluding Cordova, increased during the quarters ended September 30, 2006 and 2005 and the nine months ended September 30, 2006 and decreased during the nine months ended September 30, 2005 due to changes in regional power prices.

**Power Segment**

Our Power segment consists of assets in Brazil, Asia and Central America. We continue to pursue the sales of our remaining Asian and Central American investments and are evaluating opportunities to dispose of our interests in Brazil, including our Porto Velho facility. As of September 30, 2006, our remaining exposure is approximately $745 million consisting of $680 million in equity investments and notes receivable and approximately $65 million in financial guarantees and letters of credit in these areas. A further discussion of our power operations follows.

*Brazil*

As of September 30, 2006, our remaining exposure (including letters of credit and guarantees) in Brazil was approximately $575 million. Of this amount, approximately $330 million relates to our Porto Velho project. The state owned facility that purchases power generated by the facility has approached us with the opportunity to potentially sell them our interest in this power plant. As we evaluate this potential opportunity, we could be required to record a loss based on the potential value we may receive if we sell the facility. The remainder of our exposure in Brazil relates primarily to our Manaus and Rio Negro power plants, and our Bolivia-to-Brazil and Argentina to Chile pipelines (see further discussion in Item 1. Financial Statements, Note 15).

*Other International Power*

As of September 30, 2006, we had a net remaining exposure (including letters of credit and guarantees) of approximately $170 million in Asia and Central America. In October 2006, we closed the sale of our investment in the Sengkang project. The disposal of this investment reduced our exposure in this area by approximately $60 million. We expect to sell substantially all of the remaining assets during the fourth quarter of 2006 and early 2007. See Item 1, Financial Statements, Note 3 for further information on our divestitures.

During 2006 and 2005, we recorded impairments and gains on sales based on the value received or expected to be received upon closing the sales of our Asian and Central American assets. Our results were also negatively impacted by the reduction in earnings as each facility was sold and by our decision to not realize earnings from certain of our Asian and Central American assets based on our inability to realize those earnings through their expected selling price. We did not recognize earnings of approximately $2 million and $9 million for the quarters ended September 30, 2006 and 2005, and $14 million and $28 million for the nine months ended September 30, 2006 and 2005. As we complete the sale of our Asian and Central American assets, changes in regional political and economic conditions could negatively impact the anticipated proceeds, which could result in additional impairments.

*Domestic Power*

As a result of the sales of our interests in the MCV power facility in August 2006, and our interests in the Capitol District Energy Center Cogeneration Associates (CDECCA) and Berkshire power facilities in October 2006, we have completed the disposition of our domestic power facilities. We recorded a gain in the third quarter of 2006 of approximately $13 million upon the sale of MCV. The sale of our CDECCA and Berkshire facilities did not result in a significant net gain or loss. The disposition of these power facilities impacted certain contracts in our Marketing & Trading segment, which are further discussed in our Marketing and Trading segment.

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

| | Quarters Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2006 | 2005 | 2006 | 2005 |
| | (In millions) | | | |
| EBIT by Area | | | | |
| *Brazil* | | | | |
| EBIT from operations | $20 | $ 15 | $ 52 | $ 50 |
| *Other International Power* | | | | |
| Asia | | | | |
| Impairment related to anticipated sales | — | — | (7) | (93) |
| Gain on sale of KEICO and PPN power plants | — | 109 | 1 | 131 |
| EBIT from operations | 1 | (1) | 1 | 14 |
| Central and Other South America | | | | |
| Impairments related to anticipated sales, net[1] | — | — | (2) | (70) |
| EBIT from operations | (1) | (2) | (1) | 8 |
| EBIT from other international plants and investments[2] | — | 1 | 2 | 15 |
| *Domestic Power* | | | | |
| Gain on sale of MCV and impairment of investment | 13 | (159) | 13 | (162) |
| Favorable resolution of bankruptcy claim | — | — | — | 53 |
| Other | (2) | (2) | (11) | 4 |
| Gain on sale of cost basis investment[3] | 12 | — | 13 | — |
| *Other*[4] | (5) | (7) | (10) | (37) |
| EBIT | $38 | $ (46) | $ 51 | $ (87) |

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

(2) EBIT from other international plants and investments includes a $17 million dividend on investment fund recorded in the second and third quarters of 2005.

(3) In October 2006, we sold our remaining shares in this investment and will record a gain of approximately $34 million in the fourth quarter of 2006.

(4) Other consists of the indirect expenses and general and administrative costs associated with our domestic and international operations. Also included is 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 substantially all of the assets and operations in this segment. For the nine months ended September 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 decrease in our EBIT loss for the quarter and nine months ended September 30, 2006 as compared to the same periods in 2005:

| | Favorable (Unfavorable) Quarter Impact | Favorable (Unfavorable) Nine Months Impact |
|---|---|---|
| | (In millions) | |
| Western Energy Settlement charge in 2005 | $ — | $ 72 |
| Lease termination in 2005 | — | 27 |
| Foreign currency fluctuations on Euro-denominated debt | — | (46) |
| Decrease in litigation, environmental and other charges | 45 | 9 |
| (Higher) lower losses on extinguishment or restructuring of debt facilities | (17) | 3 |
| Other | 22 | 53 |
| Total impact on EBIT | $ 50 | $118 |

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.

### Interest and Debt Expense

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

| | Quarters Ended September | | Nine Months Ended September | |
|---|---|---|---|---|
| | 2006 | 2005 | 2006 | 2005 |
| | (In millions) | | | |
| Long-term debt, including current maturities | $303 | $325 | $965 | $ 986 |
| Other | 7 | 12 | 25 | 27 |
| | $310 | $337 | $990 | $1,013 |

Interest and debt expense for the quarter and nine months ended September 30, 2006 was lower than the same periods in 2005. While interest decreased with an approximate $3 billion net reduction of debt, we experienced higher fees on our letters of credit facility.

### Income Taxes

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

| | Quarters Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2006 | 2005 | 2006 | 2005 |
| | (In millions, except for rates) | | | |
| Income taxes | $ (86) | $(136) | $81 | $(100) |
| Effective tax rate | (176)% | 32% | 11% | 47% |

For a discussion of our effective tax rates and other matters impacting our income taxes, see Item 1, Financial Statements, Note 6.

### Discontinued Operations

Our loss from discontinued operations for the quarter and nine months ended September 30, 2005, consisted primarily of the impairment of our interest in the Macae power facility in Brazil. We continue to have potential exposures related to our Macae and Nejapa international power operations, which totaled $133 million as of September 30, 2006. This exposure primarily relates to a guarantee arising out of the sale of our Macae power facility.

## Commitments and Contingencies

See Item 1, Financial Statements, Note 10, 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 September 30, 2006 from $18 billion at the end of 2005. Through our actions to date, current operating trends, and remaining asset sales scheduled for the remainder of 2006, we will work towards achieving our net debt target (debt, less cash) of approximately $14 billion by the end of the year.

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

| | |
|---|---|
| Available cash | $0.6 |
| Available capacity under our credit agreements | 1.0 |
| Net available liquidity at September 30, 2006 | $1.6 |

*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 and meet working capital requirements. We currently anticipate approximately $0.4 billion of capital investments in our pipeline business and between $0.3 billion and $0.4 billion in our exploration and production business, intended to both maintain and grow these businesses.

We have no significant debt maturities in the fourth quarter of 2006. Our 2007 debt maturities are 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. We expect to fund these debt maturities and potential redemptions through a combination of cash on hand, cash flow generated from our operations, borrowings under our revolvers or new financing transactions.

*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 below current market prices, which resulted in us posting significant cash margin deposits and letters of credit with the counterparties for the value of these instruments. During the first nine months of 2006, approximately $0.9 billion of posted cash margins were returned to us, with $0.5 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. As a result, a substantial portion of our remaining margin consists of letters of credit. In the fourth quarter of 2006, based on current prices, we expect approximately $0.2 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, and if prices decrease, we will be entitled to recover some of this amount earlier than anticipated. Based on our derivative positions at September 30, 2006, a $0.10/MMBtu increase in the price of natural gas would result in an increase in our margin requirements of $15 million, which consists of $3 million for transactions that settle for the remainder of 2006, $3 million for transactions that settle in 2007, $3 million for transactions that settle in 2008 and $6 million for transactions that settle in 2009 and thereafter.

- *Hurricanes.* We continue to 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 $600 million, of which we estimate approximately $340 million will be unrecoverable from insurance. Of the unrecoverable amount, we estimate that approximately $260 million will be capital related expenditures. We have incurred capital costs of approximately $180 million through September 30, 2006 that are not recoverable through insurance.

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 2006, we entered into additional derivative contracts related to our 2006 and 2007 natural gas production. The following table shows as of September 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 | 28 | $ 4.89 | 30 | $ 7.00 | 15 | $ 9.50 | 25 |
| 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 | 357 | $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 nine months ended September 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 | $ 0.7 | $(0.1) |
| Non-cash income adjustments | 0.9 | 0.9 |
| Change in broker margin and other deposits[1] | 0.9 | (0.7) |
| Change in other assets and liabilities | (0.5) | (0.5) |
| Total cash flow from operations | $ 2.0 | $(0.4) |
| **Other Cash Inflows** | | |
| *Continuing investing activities* | | |
| Net proceeds from the sale of assets and investments | $ 0.5 | $ 1.1 |
| Other | 0.1 | 0.3 |
| | 0.6 | 1.4 |

| | 2006 | 2005 |
|---|---|---|
| | (In billions) | |
| *Continuing financing activities* | | |
| Net proceeds from the issuance of long-term debt | 0.1 | 1.2 |
| Proceeds from issuance of common and preferred stock | 0.5 | 0.7 |
| Contribution from discontinued operations[2] | 0.1 | 0.1 |
| | 0.7 | 2.0 |
| Total other cash inflows | $ 1.3 | $ 3.4 |
| **Cash Outflows** | | |
| *Continuing investing activities* | | |
| Capital expenditures[3] | $ 1.6 | $ 1.3 |
| Net cash paid for acquisition | — | 1.0 |
| | 1.6 | 2.3 |
| *Continuing financing activities* | | |
| Payments to retire long-term debt and redeem preferred interests | 3.0 | 1.5 |
| Redemption of preferred stock of a subsidiary | — | 0.3 |
| Dividends and other | 0.1 | 0.1 |
| | 3.1 | 1.9 |
| Total other cash outflows | $ 4.7 | $ 4.2 |
| Net change in cash | $(1.4) | $(1.2) |

(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 $0.5 billion collected as commodity prices decreased and contracts were settled.

(2) Amounts contributed from discontinued operations above are net of approximately $0.2 billion of debt repayments associated with the Macae power facility.

(3) Includes $0.8 billion related to production activities and $0.8 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, oil 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 September 30, 2006 and changes in these derivatives from January 1, 2006 to September 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 | $ 139 | $ 38 | $ — | $ — | $— | $ 177 |
| Liabilities | (53) | (36) | (28) | (8) | — | (125) |
| Total derivatives designated as hedges | 86 | 2 | (28) | (8) | — | 52 |
| Other commodity-based derivatives | | | | | | |
| Exchange-traded positions[1] | | | | | | |
| Assets | 55 | 220 | 66 | — | — | 341 |
| Liabilities | (8) | (10) | — | — | — | (18) |
| Non-exchange-traded positions | | | | | | |
| Assets | 106 | 95 | 60 | 47 | 10 | 318 |
| Liabilities | (319) | (459) | (275) | (234) | (7) | (1,294) |
| Total other commodity-based derivatives | (166) | (154) | (149) | (187) | 3 | (653) |
| Total commodity-based derivatives | $ (80) | $(152) | $(177) | $(195) | $ 3 | $ (601) |

(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 | 212 | (33) | 179 |
| Change in fair value of contracts | 481 | 129[1] | 610 |
| Reclassification of derivatives that no longer qualify as hedges[2] | 6 | (6) | — |
| Option premiums paid (received) | 6 | (11) | (5) |
| Assignment of certain natural gas contracts | — | 31 | 31 |
| Net change in contracts outstanding during the period | 705 | 110 | 815 |
| Fair value of contracts outstanding at September 30, 2006 | $ 52 | $(653) | $ (601) |

(1) Includes a $49 million gain associated with the assignment of our contracts to supply natural gas to certain municipalities in Florida. Also includes a loss on natural gas supply agreements related to our MCV plant upon the sale of this facility in August 2006.
(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.

*Assignment of Certain Natural Gas Contracts.* In September 2006, we sold or entered into offsetting derivative transactions to eliminate the price risk associated with a substantial portion of our remaining legacy natural gas derivatives. We paid proceeds of approximately $31 million related to this transaction.

### 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 | | | | | |
| September 30, 2006 | $ 32 | $ (81) | $(113) | $ 151 | $119 |
| 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 $7 million and $29 million as of September 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. We may experience changes in our Value-at-Risk in the future if commodity prices are volatile.

## Item 4. Controls and Procedures

### Evaluation of Disclosure Controls and Procedures

As of September 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 September 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 third quarter of 2006.

## PART II — OTHER INFORMATION

### Item 1. Legal Proceedings

See Part I, Item 1, Note 10, which is incorporated herein by reference. Additional information about our legal proceedings can be found, in Part I, Item 3 of our 2005 Annual Report on Form 10-K filed with the SEC and in Part II, Item 1 of our Quarterly Report on Form 10-Q for the quarters ended March 31 and June 30, 2006.

*Natural Buttes.* In May 2003, we met with the United States Environmental Protection Agency (EPA) to discuss potential prevention of significant deterioration violations due to a possible de-bottlenecking modification at our facility in Utah. The EPA issued an Administrative Compliance Order as to this and other matters and we entered into settlement negotiations with the EPA. In September 2005, we were informed that the EPA referred this matter to the U.S. Department of Justice. We have since entered into tolling agreements to facilitate continuing settlement discussions. In October 2006, the EPA indicated that it would settle this matter for a penalty of $420,000, largely related to alleged excess emissions 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 a substantial portion of any eventual penalty. We believe the resolution of this matter will not have a material adverse effect on our financial condition.

### 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 and operating 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

None.

### Item 5. Other Information

None.

### Item 6. Exhibits

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

| Exhibit Number | Description |
|---|---|
| 3.B | By-laws effective as of October 26, 2006 (Exhibit 3.B to our Current Report on form 8-K filed October 26, 2006). |
| *4.A | Eleventh Supplemental Indenture dated as of August 31, 2006, between El Paso Corporation and HSBC Bank USA, National Association, as trustee. |
| 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). |
| 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). |
| *10.F | Form of Indemnification Agreement executed by El Paso for the benefit of each officer and effective the date listed in Schedule A thereto. |
| *10.G | Amendment No. 1 to the El Paso Corporation Employee Stock Purchase Plan effective as of October 26, 2006. |
| *10.H | Amendment to the Executive Award Plan of Sonat Inc. effective as of October 26, 2006. |
| *10.I | Amendment No. 5 to the El Paso Corporation Omnibus Plan for Management Employees effective as of October 26, 2006. |

| Exhibit Number | Description |
|---|---|
| *10.J | Amendment No. 5 to the El Paso Corporation Strategic Stock Plan effective as of October 26, 2006. |
| *10.K | Amendment No. 3 to the El Paso Corporation 1999 Omnibus Incentive Compensation Plan effective as of October 26, 2006. |
| *10.L | Amendment No. 3 to the El Paso Corporation 1995 Omnibus Compensation Plan effective as of October 26, 2006. |
| *10.M | Amendment No. 6 to the El Paso Corporation 2001 Omnibus Incentive Compensation Plan effective as of October 26, 2006. |
| *10.N | Amendment No. 3 to the El Paso Corporation Stock Option Plan for Non-Employee Directors effective as of October 26, 2006. |
| *10.O | Amendment No. 3 to the 2001 Stock Option Plan for Non-Employee Directors effective as of October 26, 2006. |
| *10.P | Amendment No. 1 to the El Paso Corporation 2005 Compensation Plan for Non-Employee Directors effective as of October 26, 2006. |
| *10.Q | Amendment No. 2 to the El Paso Corporation 2005 Omnibus Incentive Compensation Plan effective as of October 26, 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: November 6, 2006

/s/ D. Mark Leland

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

Date: November 6, 2006

/s/ John R. Sult

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